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COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the City of Holyoke Gas and Electric Light Department for Approval of the 1985 Supplement to the Second Long-Range Forecast of Gas Requirements and Resources	Docket No. 85-23

FINAL DECISION

Susan F. Tierney
Hearing Officer

Calvin Young
Analyst
August 13, 1986

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The Energy Facilities Siting Council ("Siting Council") APPROVES the 1985 Supplement to the Second Long-Range Forecast of Gas Requirements and Resources ("1985 Supplement") of the City of Holyoke Gas and Electric Light Department ("Holyoke" or "Department"), subject to the Conditions imposed herein.[1]

I. Introduction

A. History of Proceedings

Holyoke filed its 1985 Supplement on December 16, 1985. A Notice of Adjudication of the 1985 Supplement was issued and duly published in accordance with the Hearing Officer's instructions. As no petitions to intervene or motions to participate as an interested person were filed by the deadline specified in the Notice of Adjudication, this proceeding was left in an uncontested posture.

While consideration of the 1985 Supplement was pending, the Siting Council Staff ("Staff") issued a Notice of Inquiry into an Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Massachusetts Natural Gas Utilities ("the Notice of Inquiry") in Siting Council Docket No. 85-64. The purpose of the Notice of Inquiry was to solicit comments from all Massachusetts natural gas companies subject to the Siting Council's jurisdiction as to how the Siting Council's review process for gas company forecasts and supply plans could be made more efficient and effective, and its decisions on these forecasts and supply plans more meaningful.

The Notice of Inquiry set forth a large number of specific suggestions for changes in the standards and procedures followed by the Siting Council in gas company forecast and supply plan proceedings. After requesting and receiving written comments on these suggestions from all of the regulated gas companies, the Staff held 10 days of hearings on the Notice of Inquiry in November of 1985. Holyoke appeared at the hearings on November 15, 1985, and answered numerous questions from the Staff regarding not only the issues raised in the Notice of Inquiry but also the contents of the Supplement itself. While Holyoke's witnesses did not testify under oath, their comments cast considerable light on certain aspects of the 1985 Forecast. These comments are referred to in this Decision as ("Tr., 11/15/85 at __"), and will be made a part of the record of this proceeding.

As stated in the Procedural Order of October 22, 1985 in Docket No. 85-64, the present Decision is made on the basis of the Siting Council standards and procedures which prevailed at the time the 1985 Forecast was filed. However, certain applicable changes to those standards and procedures resulting from the Notice of Inquiry and the resultant Order

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[1] The Energy Facilities Siting Council approved the Third Annual Supplement to the Second Long Range Forecast in July, 1985. City of Holyoke Gas and Electric Light Department, 13 DOMSC 47 (1985).

in Docket No. 85-64 are discussed infra, along with suggestions and instructions for their implementation in the 1986 filing.

B. Record

This Decision is made on a record consisting of: the 1985 Supplement; the transcript of the Notice of Inquiry in Siting Council Docket No. 85-64; and a letter from Mr. Charles Haller, Assistant Manager of the City of Holyoke Gas and Electric Light Department, to Mr. Calvin Young, Staff, dated July 8, 1986.

C. Background

Holyoke is a municipal utility and is the ninth largest distributor of natural gas in the Commonwealth in terms of annual gas sendout.[2] Table 1 reflects Holyoke's total annual gas sendout and the average number of customers for split year 1984/85 by customer class.

Table 1 Total Annual Firm Sendout and Average Number of Customers for 1984/85

Class of Customer	Annual Sendout (MMcf)	Average Number of Customers
Residential Heat	586	6,329
Residential Non-Heat	75	3,342
Industrial	101	4
Commercial & Industrial	748	919
Company & Unaccounted	704	---
Total	2,204	10,594

Of the 10,594 customers, 91 percent were residential customers. Of the approximately 2,200 MMcf of firm sendout, 26.6 percent went to residential gas heat customers, 33.9 to commercial/industrial customers, and 31.9 to and company use and unaccounted-for sendout.

D. Prior Condition

In its last decision involving Holyoke, the Siting Council imposed one condition:

1. That Holyoke provide cost studies determining the levels at which its MDQ and AVL for Tennessee gas should be set and the quantity of Bay State and propane gas supplies it will need, or provide other justification for such quantities.

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[2] G. Aronson, Report of the Energy Facilities Siting Council, "The Gas Industry in Massachusetts," (March, 1983).

Pursuant to Condition 1, Holyoke has submitted a study comparing the incremental costs of seven options of MDQ for Tennessee gas and underground storage with the cost of supplementals. The Department's cost is discussed infra. at 15-19.

II. Scope and Standard of Review

The Commonwealth of Massachusetts mandates that the Siting Council review sendout forecasts of each gas utility to ensure the accurate projection of gas sendout requirements of a utility's market area. The Siting Council's Rules 62.9(2) (a), (b) and (c), require the use of accurate and complete historical data and a reasonable statistical projection method. In its review of a forecast, the Siting Council determines whether a projection method is reasonable according to whether the methodology is: (a) appropriate, or technically suitable for the size and nature of the particular gas utility's system; (b) reviewable, or presented in a way such that the results can be evaluated and duplicated by another person given the same information; and (c) reliable, that is, provides a measure of confidence that the gas utility's assumptions, judgements and data will forecast what is likely to occur. The Siting Council applies these criteria on a case-by-case basis.

In order to ensure that the required gas is supplied to a utility's customers with a minimum impact on the environment at lowest cost, the Siting Council focuses its supply review on the adequacy, cost and reliability of gas supplies needed to meet projected sendout requirements. The adequacy of supply is measured by the company's ability to meet projected peak day, cold-snap, and total annual firm sendout requirements with sufficient reserves under both normal and design weather conditions. The review of cost of supply addresses minimization of cost in concert with notions of adequacy and reliability of natural gas supply. The reliability of supply reviews the likelihood that the resources of natural gas will be available to meet or contribute to meeting sendout requirements under normal year, design year, peak day, cold-snap conditions.

III. Analysis of Sendout Requirements

A. Overview of Forecast Methodology

Holyoke utilizes the same forecast method as it has in prior filings.[3] The Department employs historical data on base and heating use per customer and the number of customers to forecast sendout for residential with heating, residential without heating, commercial/industrial and industrial customer classes. Total firm sendout is the sum of the sendout for each class and estimates of company use and unaccounted-for gas.

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[3] In Re: City of Holyoke Gas and Electric Department, 13 DOMSC 47, 50 (1985). The Source of this approach is cited therein.

Sendout for each customer class is the sum of the sendout for the heating and non-heating seasons, where the heating season is from November through March. In a year with normal weather, the heating season for each class is calculated in the following manner:

[5 x (class monthly base use per customer) x (the number of customers)] + [(the class heating load factor) x (heating season normal year's degree days) x (the number of customers)].

For each class, non-heating season sendout in a normal year is:

[7 x (class monthly base use per customer) x (the number of customers)] + [(the class heating load factors) x (non-heating season normal year's degree days) x (the number of customers)].

The design year heating season and non-heating season sendout requirements are calculated in a similar fashion.

Holyoke uses actual 1983-84 sales data to derive base use per customer and heating load factors for each customer class. These are adjusted downward, judgementally, by approximately 1.5 percent each year of the forecast period in order to account for conservation. The method employed to project the number of customers for each forecast year is unclear.[4]

Holyoke uses a split-year's total of 6505 degree days to forecast sendout requirements in a normal weather year, a split-year's total of 6985 degree days to forecast sendout requirements in a design weather year, and 68 degree days to forecast sendout requirements for a peak day.

For each customer class, peak day sendout is equal to:

[(daily base use per customer) x (the average of customers)] + [(heating use per degree day) x (peak degree days)].

Summing across customer classes gives peak day sendout. Daily base per customer is obtained by dividing heating period base use per customer by 151 days. Heating use per degree day is obtained by dividing heating use per customer by a normal year's degree-days.

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[4] Holyoke has stated that it projects the number of customers based upon historical data. However, the methodology for forecasting the average number of customers is not stated. This issue is addressed <u>infra</u> at 13.

B. Impact of Weather and Conservation

1. Weather Data

Holyoke uses a 65° Fahrenheit standard as the temperature above which heating load is zero. Holyoke employed this standard to derive degree days -- which is a measure of coldness used in determing normal and design year criteria -- and to forecast heating load increments. The normal year standard of 6505 degree days is the average of 30 split years' degree-day data. The design year standard of 6985 degree days is the coldest split year in 30 years. The peak day of 68 is the coldest 24 hour period in 30 years.

Holyoke prefers a design year criterion based upon recurrence expectancy, that is, based upon a worst weather year within a specified time period, rather than a criterion in which a specified percentage of a normal year's sendout requirement is added to the normal year's sendout requirement.[5]

Table 2 Degree Day Data

Split Year	Non-Heating Season	Heating Season	Total Split-Yr.	Peak Day
1980/81	1235	5396	6631	68
1981/82	1411	5175	6586	65
1982/83	1221	4633	5854	60
1983/84	1238	4842	6080	60
1984/85	1017	4889	5906	57
Normal	1321	5184	6505	--
Design	1373	5612	6985	68

As indicated in Table 2, split-year 1984/85 had a warmer than normal heating and non-heating seasons. The actual peak day of 57 degree days is considerably lower than the design peak day of 68 degree days.

2. Peak Day Requirement

In split year 1984/85, the sendout was 11.6 MMcf for the actual peak day of 57 degree days. The design forecast is expected to decline from 12.3 MMcf in 1985/86 to 12.0 MMcf in 1989/90. The forecast projects this decrease because of adjustments in total use per customer for conservation.

3. Cold Snap Requirements

The coldest two-to-three week period for Holyoke occurred in January 1982, from the 10th day of the month to the 27th day. Degree days ranged from a low of 42 to a high of 67. The total number of

[5] See Tr. 11/15/86, at 113.

degree days for the 18-day period was 982, averaging approximately 55 degree days per day.

4. Conservation[6]

Holyoke continues to adjust total use per customer in each class by approximately - 1.5 percent for each forecast year. The Department expects more efficient appliances and increased insulation to reduce average use per customer.

In the last decision, the Siting Council expressed its concern that projecting a decrease in base and heating use factors of 1.5 percent would lead to underestimation of sendout requirements.[7] As shown in Table 3, total use per customer for the heating season and non-heating season has not demonstrated any pattern of decline except in the commercial/industrial and industrial classes. Indeed, residential with gas heating and residential without gas heating show a pattern of increase for both heating and non-heating season. In addition, the commercial/industrial class total use per customer has been increasing in the non-heating season.

Table 3 Total Use Per Customer by Class
(MMcf)

	Residential with heat	Residential without heat	Commercial/ Industrial	Industrial
		Non·Heating Season		
1980/81	25.08	11.34	-----	--------
1981/82	26.02	11.62	312.0	13,531.7
1982/83	26.49	12.20	318.1	13,808.0
1983/84	24.36	12.62	299.7	15,238.6
1984/85	29.45	13.2	327.0	10,818.0
		Heating Season		
1980/81	62.01	8.10	-----	--------
1981/82	64.81	8.30	588.4	19,452.7
1982/83	63.30	8.61	555.0	18,209.0
1983/84	68.77	8.90	570.2	16,327.1
1984/85	70.40	9.30	534.0	15,818.0

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[6] For a discussion of Department-sponsored conservation efforts and Department's evidence concerning conservation, See: In Re: Holyoke Gas and Electric Light Department, 13 DOMSC 47, 56 (1985), and Tr. 11/15/85, at 134-5.

[7] In Re: Holyoke Gas and Electric Light Department, 13 DOMSC 47, 57 (1985).

Therefore, it is difficult to justify the Department's continuing and indiscriminate decrease in total use per customer due to conservation. The Department appears to be mechanically determining its use factors. Holyoke simply trends the previous year's use factors for conservation instead of adjusting use factors judgementally for the underlying dynamics of its retail market.

C. Forecast of Total Firm Sendout

In the last decision involving Holyoke, the Siting Council expressed its concern that Holyoke was underestimating normal and design year sendout.[8] The Siting Council recommended that Holyoke reassess its method of adjusting total usage per customer. Holyoke has not indicated that it evaluated or changed its estimating approach. Again, the Siting Council remains concerned that Holyoke is underestimating normal and design sendout for the forecast period in the 1985 Supplement.

1. Normal year

The actual sendout for 1984/85, including interruptibles, was 2,570 MMcf. Total sendout would have been 2,664 MMcf, had a normal year occurred. The 1984 Supplement forecasted a normal year's sendout at 2,273 MMcf. This represents a difference of 371 MMcf, or 16.5 percent, between the normalized sendout for 1984/85 last and the last forecast of sendout requirements for a normal year.

Furthermore, Holyoke overestimated the number of customers in three out of four customer classes in the 1984 Supplement. Only, the industrial class which has 4 customers was not overestimated. Had the projected customers for the residential with gas heat, residential without gas heat and commercial/industrial classes materialized, the underestimation of normalized sendout in the 1984 Supplement for split year 1984/85 would have been greater.

Although the Department regards a difference between forecasted and actual normalized sendout of less than 15 to 20 percent to be an acceptable level of accuracy, the Siting Council notes that the difference between Holyoke's normal year's sendout requirement and its design year's is less than 4 percent[9].

The Department expects total sendout to decline each year of the forecast period from 2,342 MMcf in 1985/86 to 2,060 MMcf in 1989/90, or at a 3.2 percent per annum.

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[8] Ibid.

[9] See Tr. 11/15/85 at 128.

Table 4 Sendout Requirements for a Normal Year (MMcf)

	Non-Heating Season	Heating Season	Total
1985/1986	1,054	1,288	2,342
1986/1987	1,054	1,288	2,342
1987/1988	1,048	1,278	2,326
1988/1989	804	1,268	2,072
1989/1990	800	1,260	2,060

2. Design Year

Holyoke expects total firm sendout for a design year to decline from 2,415 MMcf in 1985/86 to 2,129 MMcf in 1989/90. The significant drop in sendout between 1987/88 and 1988/89 is due to the Holyoke's planned energy resource recovery plant discussed infra. at 11 and 12.

Table 5 Sendout Requirements for a Design Year and Peak Day (MMcf)

	Non-Heating Season	Heating Season	Total	Peak Day
1985/1986	1,063	1,352	2,415	12.36
1986/1987	1,063	1,351	2,414	12.33
1987/1988	1,057	1,341	2,398	12.23
1988/1989	813	1,331	2,144	12.13
1989/1990	808	1,321	2,129	12.02

D. Forecast of Number of Average Customers

1. Residential Customers with Gas Heating

The total number of residential customers with gas heating has declined from 7,089 in 1980/81 to 6,329 in 1984/85. However, the number of customers increased by 13 customers in split-year 1984/85.

As indicated in Table 6, Holyoke is forecasting an increase of 50 customers in 1985/86 and 1986/87 and of 30 customers per year thereafter.

2. Residential Customers without Gas Heating

The number of residential customers without gas heating has increased from 2917 in 1980/81 to 5342 in 1984/85. However, the number of customers peaked in 1982/83 and has declined in each of the last two years.

As indicated in Table 6, Holyoke is projecting that the number of residential customers without heating will increase by 10 customers per annum.

3. Commercial/Industrial

After peaking in 1981/82, the number of commercial/industrial customers has declined by about 28 customers per year from 1,003 in 1981/82 to 919 in 1984/85.

As indicated in Table 6, Holyoke is projecting an increase of 20 customers in 1985/86 and 1986/87 and of 10 customers, annually, thereafter.

Table 6
Forecast of Customers from 1985/86 through 1989/90

Year	Residential Heating	Residential w/o Heating	Commercial/ Industrial
1985/86	6379	3352	939
1986/87	6429	3362	959
1987/88	6454	3372	969
1988/89	6479	3382	979
1989/90	6504	3392	989

Again, Holyoke provides no documentation or explanation of how it projects the number of customers for its customer classes.

E. Company Use & Unaccounted for Gas, Interruptible and Resale Gas Customers

1. Company & Unaccounted for Gas

Company and unaccounted for sendout in heating and non-heating seasons during the forecast period are calculated as being equal to 4 percent of sendout for the 4 firm customer classes in each year of the forecast period. Internal use of gas is comparatively large because Holyoke uses gas to power its district steam system. As shown in Table 7, a significant drop in sendout is projected to begin in 1988/89, when the construction of an energy resource recovery plant will replace Holyoke's steam plant in the district steam system. The steam produced by the energy resource recovery plant will be purchased by the Department.

Since the 1984 Supplement projected the energy resource recovery plant to be operational in 1987/88, the Department should monitor and report on the construction progress of this facility in the narrative of its next filing.[10]

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[10] See In Re: Holyoke Gas and Electric Department, 13 DOMSC 47, 54 (1985).

Table 7 Company and Unaccounted for Sendout

Split Year	Non-Heating Season	Heating Season
1985/86	481	259
1986/87	482	260
1987/88	481	259
1988/89	244	259
1989/90	244	259

2. Resale and Interruptible

In the past, Holyoke has resold gas to Bay State Gas Company ("Bay State"), most recently, in November of 1982.[11] Holyoke anticipates no resale to Bay State in the future. Holyoke forecasts a significant increase in interruptible sendout. For the five years preceding the forecast period, interruptible sendout was 168 MMcf in 1980/81; 158 MMcf in 1981/82; 181 MMcf in 1982/83; 240 MMcf in 1983/84; and 356 MMcf in 1984/85. In contrast, interruptible sendout is expected to be 439 MMcf throughout the forecast period. The significant increase in expected sales volume was due to the addition of a large volume interruptible customer in November, 1984.[12] In its next filing, Holyoke should report on the impact of current and forecasted oil prices on its expected interruptible sales.

F. Summary

The Siting Council finds Holyoke's methodology to be sound and appropriate for a gas utility of its size and resources. The Siting Council appreciates the backup work papers provided in the 1985 Supplement, which improved the reviewability of the filing.

However, the Siting Council notes that the Department's methodology for forecasting sendout is only as reliable as the underlying data and the intimate knowledge of community activity used in making judgemental adjustments to the data. The Department judgementally decreases use per customer by 1.5 percent for conservation while ignoring other factors such as gas prices, oil prices, employment and income.

The evidence before the Siting Council does not support the Department's judgemental adjustment of customer usage for conservation. The Siting Council does not dispute the impact of conservation upon usage per customer. Rather, the concern of the Siting Council is that customer usage levels depend upon other variables in addition to conservation for which use per customer might be adjusted. Condition

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[11] Response to Information and Documents Request No. 10 in Docket No. 84-23.

[12] In Re: Holyoke Gas and Electric Department, 13 DOMSC 47, 54 (1985).

One of this Decision addresses the matter of the possible underestimation of firm sendout.

On the basis of the record, the Siting Council has concerns regarding the reliability of Holyoke's methodology. In particular, the record suggests that Holyoke's methodology may underestimate sendout requirements due to the Department's adjusting sendout only for conservation while other variables impacting upon base and heating use factors are ignored. Thus, the Department is required in its response to Order No. 6 in Docket No. 85-64 to determine the impact of its adjustments for conservation upon forecast accuracy. Discussed <u>infra.</u> at 25.

The Siting Council has concerns about the ability of Holyoke to meet sendout requirements in the future. In its next filing, the Department <u>must</u> address how it will meet requirements in the latter years of the forecast period should some of its projected supply sources not be available as expected.

Furthermore, the Siting Council in its preceding decision requested that Holyoke provide an explanation of how it forecasts the number of customers for the residential heating, residential general and commercial/industrial classes. As Holyoke has not done this, Condition Two of this Decisions orders the Department to provide such in its next filing.

Overall, the forecast is <u>appropriate</u> for a gas utility of Holyoke's size and resources, and is basically <u>reviewable</u>. The Siting Council does have reservations about the reliability of the forecast. However, the problems in this forecast are not insoluble. Several of the Conditions in this Decision and the Order in Docket No. 85-64 focus on steps Holyoke <u>must</u> take to raise the Siting Council's confidence in its forecast.

IV. <u>Resources and Facilities</u>

Holyoke relies on pipeline gas purchased from Tennessee Gas Pipeline Company ("Tennessee") to meet Holyoke's base load requirements. As peak shaving supplies, Holyoke also sends out LNG and propane air.

Holyoke purchases gas under Tennessee's G-6 Rate Schedule pursuant to a contract dated June 4, 1981. The initial termination date of the contract is November 1, 2000, with automatic extensions unless cancelled on 12-months' written notice of either party. The maximum daily quantity ("MDQ") is 7.875 MMcf. The Annual Volumetric Limitation ("AVL") is 2,787 MMcf.

In addition, Holyoke's pipeline gas supplies from Tennessee will increase pending completion of a project which has received initial approval from the Federal Energy Regulatory Commission ("FERC"). Tennessee filed in FERC Docket No. 84-441-000 et al. for a Certificate of Public Convenience and Necessity which will raise Holyoke's MDQ and

AVL to 10.0 MMcf and 3,278 MMcf, respectively. Holyoke anticipates receiving these volumes beginning in 1988/89.[13]

Furthermore, Holyoke is considering participating in the Thomas Corners Storage Project ("Thomas Corners") which would provide 330 MMcf of underground storage with a firm delivery of 3.3 MMcf per day, and an anticipated service date of 1987.[14] According to the Department, the determining issue for the project is "getting transportation."[15]

Holyoke purchases gas from Bay State under a contract dated October 25, 1978 as amended, on June 26, 1981 and on August 23, 1982. The contract contains an original termination date of March 31, 1988, but will continue in effect on a contract year basis thereafter unless cancelled on 12-months' written notice of either party.[16] As amended, the agreement provides for 157.5 MMcf firm volumes and 52 MMcf of optional volumes. The firm volumes are purchased on a take-or-pay basis. Holyoke exercises its option to purchase additional volumes by written notice to Bay State 10 days before the beginning of the month in which gas is to be purchased. The elected quantities become a take-or-pay responsibility of Holyoke.

Under the Bay State contract, Holyoke is obliged to use its best efforts to receive gas by displacement through interconnections with Bay State on the Willimansett Bridge in Holyoke and on Balboa Drive in West Springfield. Holyoke must give Bay State an hour's notice when it requests delivery by displacement. The maximum hourly take by displacement at these points are 125 Mcf and 50 Mcf respectively. There was no instance during 1984/85 wherein Bay State was unable to deliver gas through displacement when requested. If gas cannot be taken by displacement, delivery is made by trucking LNG or propane on 24 hour's notice. Bay State has responsibility for providing the trucking service.

Holyoke's four LNG facilities have a storage capacity of 14.7 MMcf and a daily design sendout of 12 MMcf. Holyoke's propane storage and

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[13]Although Tennessee expects the project to be in service beginning in 1987, Holyoke anticipates, for planning purposes, that service will begin in the 1988/89 split year. Tr. 11/15/86, at 123-125, and 1985 Supplement's Table G-23.

[14]See the 1985 Supplement's introduction.

[15]Tr. 11/15/86, at 117.

[16]The decision to terminate the LNG contract with Bay State is contingent upon completion of the Tennessee project or Holyoke's participation in Thomas Corners. Tr. 11/15/85 at 132. The Siting notes that the Department's Table G-23 indicates that Holyoke is not relying upon Bay State LNG in its supply plan to meet sendout requirements after 1987/88.

vaporization facility has a storage capacity of 18.4 MMcf and a design daily sendout of 2.4 MMcf.

Holyoke entered into contracts with 3 propane suppliers.[17] The total firm and optional quantities of propane are 27 MMcf and 54 MMcf, respectively. Holyoke anticipates contracting for propane throughout the forecast period.

V. Cost Study

In the preceding decision, the Siting Council ordered Holyoke to provide a cost study which would compare the costs of various options for AVL and MDQ for Tennessee's G-6 gas with appropriate levels of supplementals. In compliance with this condition, Holyoke submitted a cost study comparing the incremental cost of seven options involving various combinations of MDQ and AVL for Tennessee gas, delivery of gas from underground storage, and supplementals.

A. Methodological Issues

Holyoke evaluated seven options of combinations of MDQ and AVL for Tennessee rate G-6 gas, the underground storage and supplement gas in its cost study. The seven options are:

a) Tennessee rate G-6 MDQ remains at 7.875 MMcf, 330 MMcf of storage with firm transportation, and 6.0 MMcf of propane;
b) The MDQ for Tennessee gas is raised to 8.875 MMcf, with an underground storage contract for 330 MMcf and no peak shavings supplies;
c) The MDQ for Tennessee gas is raised to 8.875, with the peak shaving sendout requirement of 176.25 to be met with 88.125 MMcf of LNG and 88.125 MMcf of propane;
d) The MDQ for Tennessee gas is at 8.875 MMcf with the peak shaving sendout requirement of 176.25 to be met with 176.25 MMcf of propane gas;
e) The MDQ for Tennessee gas is set at 8.875 MMcf and the peak shaving is met with 176.25 of LNG;
f) The MDQ for Tennessee is raised to 10.0 MMcf and the peak shaving sendout requirement of 40.0 MMcf is met by propane; and
g) The MDQ for Tennessee gas is raised to 10.0 MMcf, with underground storage at 330 MMcf, and no supplemental fuels.

In the cost study, the Department compared the incremental cost of each of the seven options with respect to a base case. The base case is the actual cost of Holyoke's supplemental fuels for the 1984/85 split-year. Both Thomas Corners and the Tennessee project's increased

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[17] Holyoke has propane contracts with Burek Oil and Gas Company, Gas Supply, Inc. and Petroleum Gas Service. See the 1985 Supplement's Table G-24.

MDQ and AVL would have displaced supplemental fuels in 1984/85. Thus, Holyoke compared what the incremental cost would have been in 1984/85 for each option with the actual cost of supplemental fuels in 1984/85. The difference between supplemental fuel costs and the incremental fuel cost of an option represents the net savings that the rate payers would have had in 1984/85.

The incremental cost of each option is equal to the cost associated with increase MDQ and AVL, the storage cost with firm transportation, and the amount of LNG and propane. Supplemental fuels are required only when daily sendout exceeds the MDQ for Tennessee's pipeline gas and the daily firm deliverability from underground storage. The load duration curve which indicates the number of days that daily sendout exceeds any specified daily sendout requirement is used to determine the quantity of supplements for each option.

Holyoke is commended for performing such a study and making it available to the Siting Council. The Siting Council has indicated in its Notice of Inquiry that it will begin to scrutinize cost issues in its evaluation of company gas supply plans.

The Siting Council finds the range of supply plan options considered in the study to be appropriate for a gas utility of Holyoke's size and resources. However, the Siting Council also finds the cost study not to be reliable because of three methodological flaws. First, Holyoke used actual sendout requirements and load duration curves for 1984/85, when it should have used normalized sendout requirements and a normal year's load duration curve. Next, the Department should have used a suitable split-year during the forecast period, that is, 1987/88, 1988/89, or 1989/90 instead of the 1984/85 split-year. Finally, the Department did not consider any alternative scenarios in which the various options are evaluated.[18]

The probable impact of the first two flaws is to bias downward the net savings of all options. The greatest underestimate of net saving is likely to be for options B, F and G, since actual sendout (including interruptible sendout) will in all likelihood be greater for a normal year during the forecast period than what actually occurred in 1984/85.[19] Greater sendout requirements might lead to greater reliance upon supplemental fuel. Therefore, more supplemental fuel should be displaced by the various options resulting in greater net savings.

Also, the Department should have examined an alternate scenario involving a design split-year in its cost study. It is probable that the Department's preferred supply plan, option B, would have faired much better under design weather conditions.

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[18] Also, the price assumptions were not dated.

[19] Split-year 1984/85 was warmer than normal.

B. The Results

The results of the study are presented in Table 8. The most cost effective options are: (1) option A, which would increase the MDQ for Tennessee gas to 10.0 MMcf and purchase 40.0 MMcf of propane; and (2) option F, which would maintain the MDQ for Tennessee at 7.875 MMcf and contract for underground storage and 6 MMcf of propane as a supplemental fuel.

However, it appears that Holyoke intends to select supply plan option B.[20] In option B, Holyoke's MDQ would be raised to 8.875 MMcf and the Department would participate in Thomas Corners which would provide 100 days of 3.0 MMcf of firm transportation from underground storage. This option does not reduce the cost to rate payers, in contrast to options A and F, which would reduce costs to rate payers by approximately 500,000 dollars.[21] Thus, the opportunity cost of option B is about 500,000 dollars.

The supply plan options considered in the cost study will displace propane and LNG in Holyoke's dispatch mix. Holyoke used about 288.75 MMcf of supplemental fuels in split-year 1984/85. If Holyoke had the gas supplies from the Tennessee expansion project (option F) available in 1984/85, then its supplemental requirements would have been 40 MMcf. Under option F, total cost of supplementals would have been 1,900,000 dollars, the cost to Holyoke of the expansion project and 40 MMcf of propane gas would have been 1,400,000 dollars yielding a net savings of about 500,000 dollars. If Holyoke had the underground storage project available in 1984/85, then its supplemental requirements would have been 6.0 MMcf. Storage and propane gas costs would have been about 1,400,000 dollars also yielding a net savings of about 500,000 dollars.

Under option B, Holyoke would participate in Thomas Corners and raise its MDQ of pipeline gas from Tennessee to 8.875. Since participation in Thomas Corners (option A) would leave only 6.0 MMcf of propane to be displaced, the incremental cost of raising the pipeline MDQ to 8.875 is about 500,000 dollars while the propane it would displace would cost only 40,000 dollars. Thus, option B would not have been a cost-effective project in 1984/85.

The Department has stated that it plans for the long-run rather than for the immediate future.[22] Thus, the Siting Council may infer that Holyoke believes its preference for option B is justifiable in terms of option B's long-run economics. However, due to the one-year time

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[20] See 1985 Supplement's narrative (unnumbered) and Tr. 11/15/85 at 147.

[21] The net saving of option B is negligible.

[22] See 1985 Supplement's narrative and Tr. 11/15/85 at 147.

horizon used by the Department in its cost study the Siting Council has no evidence before it to help it determine whether option B offers savings over the other options for a longer time frame.

Still it appears to the Siting Council that option B would not be cost justifiable in the long-run unless:

(a) Holyoke's supplemental requirements increased significantly during the forecast period;
(b) pipeline gas and underground storage remained desirable due to availability and reliability; and
(c) there were a serious risk that Holyoke could not increase its pipeline volumes or obtain storage capacity at the time when they were cost effective.

In evaluating whether these conditions are likely to occur, the Siting Council offers the following comments. First, as discussed supra, the methodological flaws in the forecast method might have caused an underestimation of the quantity of the supplemental fuels that Holyoke's system will require during the forecast period for a normal year's weather. Therefore, the net fuel savings of options B and F might have been underestimated in the cost study. However, it has not been demonstrated that the growth in total sendout and supplements would be sufficient to generate an additional net savings of 500,000 dollars to make option B as cost effective as option A. Furthermore, the net savings would have to be more than 500,000 dollars to be as cost effective as option F, since the net savings of option F would also increase.

Second, Holyoke presented no evidence that pipeline gas and underground storage transportation will remain a preferred supply source based upon availability, reliability and cost.

Finally, and most importantly, the Department has not demonstrated that it will be unable to participate in future pipeline expansion projects or storage projects with firm transportation. This is critical because, on the basis of the record before the Siting Council, Holyoke's preference for option B over option F entails a sacrifice of perhaps a half million dollars in savings per year for the forecast period. Should option B become cost effective after the forecast period, then a future benefit of opting for option B now must be balanced against the current opportunity cost of option B. If a project comparable to option B were to be available to Holyoke later on if and when option B were cost effective, then selecting option B as its current supply plan cannot be justified because option A or option F could be selected as the current supply plan and a project comparable to option B could be incorporated in Holyoke's supply plan at a future date. This strategy, selecting option A or option F now and at a future date engaging in a project similar to that of option B, would not entail sacrificing 500 thousand dollars per year during the forecast period.

Therefore, the Siting Council is unable to make a finding upon whether the Department's intended supply plan, option B, is the least

Comparison of Costs of Base Case with Seven Options

Option	Incremental Pipeline Costs	Storage Cost	LNG	Propane	Total	
1. Base Case MDQ = 7.9 LNG = 210 Propane = 79	0	0	1,398	516	1,914	---
2. Option A MDQ = 7.9 Storage = 330.0 Propane = 6.0	0	1,376.8	0	39	1,416	498
3. Option B MDQ = 8.9 Storage = 330	514.4	1,376.8	0	0	1,891.2	23.2
4. Option C MDQ = 8.9 Propane = 176.25	514.5	0	0	1,115.8	1,670.3	244.1
5. Option D MDQ = 8.9 Propane = 88.1 LNG = 88.1	514.5	0	586.6	577.9	1,679.0	235.9
6. Option E MDQ = 8.9 LNG = 176.3	514.5	0	1,173.30		1,687.8	226.6
7. Option F MDQ = 10.0 Propane = 40	1,124.8	0	0	266.7	1,391.5	522.9
8. Option G MDQ = 10.0 Storage = 330	1,124.8	1,376.8	0	0		(587.1)

cost supply plan due to methodological problems in the cost study. In particular, the Department used actual sendout data for 1984/85 instead of normal and design year sendout requirements for one or more years of the forecast period, which would have been more appropriate. The use of actual sendout data could have reduced the Department's estimate of net savings for all of the options, but especially for options B and F. Hence, option B might be rated higher in a more appropriate study. In addition, the Department failed to demonstrate that its intended supply plan would be cost effective over a longer time period. In order to demonstrate that the intended supply plan is beneficial in the long run, it is necessary to have incorporated in the cost study: (a) the expected benefits for a period including years beyond the forecast; and (b) a discussion of the risk of not being able to participate in supply projects with comparable benefits beyond the forecast period. However, as discussed infra. at 24, option B might be a more reliable plan than options A or F in meeting peak day requirements. The Department's future cost studies should incorporate the kind of methodological issues raised herein.

VI. Comparison of Resources and Requirements

A. Normal Year

Tables 9 and 10 portray Holyoke's plan for meeting sendout requirements in a normal year. Requirements are met with purchases of Tennessee pipeline gas, Bay State pipeline displacement and Bay State LNG, LNG from storage, and propane for split years 1985/86 through 1987/88. For 1988/89 and 1989/90, sendout requirements will be met with Tennessee pipeline gas, firm transportation gas from underground storage and propane. Holyoke's supply plan requires it to dispatch all of its firm Bay State LNG and propane supplies during 1985/86 through 1987/88. Also, Holyoke intends to dispatch all of its firm transportation gas from underground storage and firm propane gas during 1988/89 and 1989/90. Of the 2,878 MMcf of pipeline gas available for 1985/86 through 1987/88, Holyoke intends to dispatch 2,415 MMcf in 1985/86, 2,415 MMcf in 1986/87 and 2,499 MMcf in 1987/88. Of the approximately 3,240 MMcf of pipeline gas available for dispatch in 1988/89 and 1989/90, Holyoke intends to dispatch 2,446 MMcf in 1988/89 and 2,434 MMcf in 1989/90.[23]

The Siting Council is concerned about Holyoke's reliance upon Bay State's LNG to meet its sendout requirements. Holyoke has received assurances from Bay State that it will be able to meet its contractual

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[23]Under supply plan option B, Holyoke's MDQ is 8.875 MMcf, and 365 times 8.875 MMcf is approximately 3,240 MMcf.

Table 9

Comparison of Resources and Requirements
During a Normal Year's Non-Heating Season
(MMcf)

	85/86	86/87	87/88	88/89	89/90
Requirements					
Firm	1,054	1,054	1,048	804	800
Interruptible	212	212	212	212	212
LNG Storage Refill	---	---	---	---	---
Underground Storage Refill	---	---	190	330	330
Total	1,266	1,266	1,450	1,346	1,342
Resources					
Tennessee G-6	1,246	1,246	1,430	1,326	1,322
Bay State	10	10	10	10	10
LNG (storage)	10	10	10	10	10
Propane	---	---	---	---	---
Total	1,266	1,266	1,450	1,346	1,342

Table 10

Comparison of Resources and Requirements
During a Normal Year's Heating Season
(MMcf)

	85/86	86/87	87/88	88/89	89/90
Requirements					
Firm	1,288	1,288	1,278	1,268	1,260
Interruptible	227	227	227	227	227
LNG Storage Refill	---	---	---	---	---
Underground Storage Refill	---	---	---	---	---
Total	1,515	1,515	1,505	1,495	1,487
Resources					
Tennessee G-6	1,169	1,169	1,069	1,120	1,112
Tennessee R-6	100	100	---	---	---
Thomas Corners	---	---	190	330	330
Bay State LNG	187	187	187	---	---
LNG (storage)	14	14	14	---	---
Propane purchases	27	27	27	27	27
Propane (storage)	18	18	18	18	18
Total	1,515	1,515	1,505	1,495	1,487

obligations to supply Holyoke with LNG for split-year 1985/86.[24] However, Holyoke has expressed its concern about the future reliability of LNG because Distrigas Corporation has filed for bankruptcy.[25] Distrigas of Massachusetts Corporation ("DOMAC"), a subsidiary of Distrigas Corporation, supplies Bay State with LNG which enables Bay State to resell LNG to Massachusetts and New Hampshire gas utilities including Holyoke. Thus the future availability of this source of LNG supply is uncertain. Due to this uncertainty, the Siting Council in Condition Three of this Decision will order the Department to address this issue in its next filing.

1. Non-Heating Season

Throughout the forecast period Holyoke must meet its sendout requirements for it's firm customers. Also, it intends to supply interruptible customers as well. In addition, Holyoke will send pipeline gas to underground storage beginning in 1987/88. The total requirements are equal to 1,266 MMcf in 1985/86 and 1,342 MMcf in 1989/90. Requirements reach a maximum of 1,450 MMcf in 1987/88. Interruptible sendout is not expected to increase.

Holyoke intends to dispatch Tennessee rate G-6 gas, Bay State LNG and LNG from storage to meet its non-heating season requirements. The primary source of gas supplies during the non-heating season will be Tennessee G-6 gas.

2. Heating Season

Throughout the forecast period Holyoke must meet its firm sendout requirements. Also, Holyoke expects to sendout gas to interruptible customers. Holyoke expects to require approximately 1,500 MMcf of gas supplies during the forecast period.

Holyoke intends to dispatch firm Tennessee rate G-6 gas, propane purchases and propane from storage for any design split year of the forecast period. For 1985/86 through 1987/88, the Department will also dispatch Bay State LNG and LNG from storage. For 1987/88 through 1989/90, the Department will dispatch gas from underground storage as well. In addition, interruptible Tennessee R-6 gas will be dispatched only in split-years 1985/86 and 1986/87. Supplemental gas supplies will be 246 MMcf from 1985/86 to 1987/88.

B. Design Year

Table 11 and 12 also shows Holyoke's plan for meeting sendout requirements in a design year. Requirements are met with Tennessee G-6 gas, Bay State LNG and displacement, LNG from storage, propane gas, and

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[24] Tr. 11/15/85, at 132.

[25] Tr. 11/15/85, at 127.

Table 11
Comparison of Resources and Requirements
During a Design Year's Non-Heating Season
(MMcf)

	85/86	86/87	87/88	88/89	89/90
Requirements					
Firm	1,063	1,063	1,057	813	808
Interruptible	212	212	212	212	212
LNG Storage Refill	---	---	---	---	---
Underground Storage Refill	---	---	190	330	330
Total	1,275	1,275	1,459	1,355	1,350
Resources					
Tennessee G-6	1,255	1,255	1,439	1,335	1,330
Bay State	10	10	10	10	10
LNG (storage)	10	10	10	10	10
Propane	---	---	---	---	---
Total	1,275	1,275	1,459	1,355	1,350

Table 12

Comparison of Resources and Requirements
During a Design Year's Heating Season
(MMcf)

	85/86	86/87	87/88	88/89	89/90
Requirements					
Firm	1,352	1,351	1,341	1,331	1,321
Interruptible	227	227	227	227	227
LNG Storage Refill	---	---	---	---	---
Underground Storage Refill	---	---	---	---	---
Total	1,579	1,578	1,568	1,558	1,548
Resources					
Tennessee G-6	1,189	1,189	1,189	1,210	1,210
Tennessee R-6	100	100	---	---	---
Thomas Corners	---	---	190	330	330
Bay State	210	210	157	---	---
LNG (storage)	14	14	14	---	---
Propane purchases	48	47	---	---	---
Propane (storage)	18	18	18	18	18
Total	1,579	1,578	1,568	1,558	1,548

gas from underground storage for split-years. The storage service will begin in 1987/88. LNG service is discontinued beginning with the 1988/89 split-year. Also, Holyoke expects interruptible Tennessee R-6 gas to be available to meet sendout requirements. During the forecast period, Holyoke intends to dispatch all of its firm LNG, propane and underground storage gas supplies. During the heating season, the Department will dispatch all of its firm pipeline supplies. For a design year occurring during the forecast period Holyoke would need to dispatch 1,550 MMcf in 1985/86, 1,550 MMcf in 1986/87, 3,027 MMcf in 1987/88, 2,923 MMcf in 1988/89 and 2,908 MMcf in 1989/90.

The Siting Council is concerned about the inclusion of Thomas Corners in Holyoke's supply plan beginning in 1987/88 since the Department does not have a contract for firm transportation of gas from underground storage. It appears that the availability of Thomas Corners is critical for the Department to meet its commitments after split-year 1987/88. Thus, the Department must discuss the status of Thomas Corners in the narrative of its next filing. Condition Four of this Decision addresses this issue.

Also, the Siting Council notes that Holyoke expects to have available 100 MMcf of interruptible pipeline gas during a design year.

Finally, the Siting Council is somewhat confused by Holyoke's supply plan in that for split-years 1988/89 and 1989/90 Holyoke includes more supplemental fuel in a normal year's dispatch than in a design year's dispatch. The Department should address this concern in its next filing.

1. Non-Heating Season

Throughout the forecast period Holyoke must meet its sendout requirements for its firm customers. Also, it intends to supply interruptible customers as well. In addition, Holyoke will send pipeline gas to underground storage beginning in 1987/88. The total requirements are equal to 1,275 MMcf in 1985/86 and 1,350 MMcf in 1989/90. Requirements reach a maximum of 1,459 MMcf in 1987/88. Interruptible sendout is not expected to increase.

Holyoke intends to dispatch Tennessee rate G-6 gas, Bay State LNG and LNG from storage to meet its non-heating season requirements. The primary source of gas supplies during the non-heating season will be Tennessee G-6 gas.

2. Heating Season

Throughout the forecast period Holyoke must meet its firm sendout requirements. Also, Holyoke expects to sendout gas to interruptible customers. Holyoke expects to require approximately 1,565 MMcf of gas supplies during the forecast period.

Holyoke intends to dispatch firm Tennessee rate G-6 gas, propane purchases and propane from storage for any design split year of the forecast period. For 1985/86 through 1987/88, the Department will also dispatch Bay State LNG and LNG from storage. For 1987/88 through 1989/90, the Department will dispatch gas from underground storage as well. In addition, interruptible Tennessee R-6 gas will be dispatched only in split-years 1985/86 and 1986/87. Supplemental gas supplies will be 290 MMcf in 1985/86, 289 MMcf in 1986/87, 189 MMcf in 1987/88, 18 MMcf in 1988/89 and 18 MMcf in 1989/90.

C. Peak Day

In addition to having sufficient gas supplies to meet seasonal and annual requirements of its customers, a gas utility must have sufficient supplies to meet peak day requirements.

Holyoke projects a peak day sendout which declines from 12.3 MMcf to 12.1 MMcf during the forecast period. Holyoke's supply plan would maintain 15.3 MMcf of gas supplies to meet peak-day sendout requirements. For split-years 1985/86 to 1987/88, these supplies include 7.8 MMcf of pipeline gas, 2.0 MMcf of propane gas, 3.5 MMcf of Bay State LNG by displacement, and 2.0 MMcf of LNG from storage. For 1988/89 and 1989/90, these supplies include 10.0 MMcf of pipeline gas, 3.3 MMcf of firm transportation of underground storage gas, 2.0 MMcf of propane.

Should the firm transportation of underground storage gas not be available, Holyoke will not be able to meet its peak day sendout requirements of 12.1 MMcf. Furthermore, this problem is exacerbated by the likelihood that Holyoke's peak day requirements are underestimated in the forecast. In its next filing, the Department should focus on ensuring adequate supplementals to meet peak day requirements in the latter years of the forecast. Condition Five of this Decision addresses this issue.

Also, the Siting Council notes that the supply plan for split-years 1988/89 and 1989/90 is not consistent with option B, but rather with option G, which is the least attractive option considered in the Department's own cost study. Under option B, Holyoke would have available 8.9 MMcf of pipeline gas, 3.3 MMcf of firm transportation of underground storage and 2.0 MMcf of pipeline gas for a total of 14.2 MMcf of gas which would be sufficient to meet sendout requirements. Thus, option B would meet peak day requirements during the 1988/89 and 1989/90 split years. Thus, the cost study should have examined the necessary supplementals needed to meet peak day sendout.

D. Cold Snap

The Siting Council has defined a "cold snap" as a period of peak or near-peak weather conditions, similar to the two-to-three week period experienced during the 1980/81 hearing season. The Department's ability to meet the requirements of its customers during a cold snap depends on it daily pipeline entitlements, its daily supplemental sendout capacity and its storage inventories.

For the split years 1985/86 through 1987/88, the Department is in a comfortable position with regard to its ability to meet sustained periods of extreme sendout. Only at degree days exceeding 62 would Holyoke have to use gas other than Tennessee pipeline and Bay State displacement. Sixty-two degree days was exceeded only twice during the cold snap of 1981/82. On such days, Holyoke would have to produce at most 0.5 MMcf of supplemental sendout during the forecast period. Given the daily supplemental sendout capacity of 12.4 MMcf, Holyoke would be able to meet peak day production of 0.5 Mcf even if storage is well below capacity. Holyoke's estimate of its ability to provide service during a cold snap is based on assumptions that: 1) no LNG or propane would be available by truck; 2) LNG storage is at 70 percent; and 3) propane storage at 50 percent of capacity. In this scenario, 12.4 MMcf is available for sendout in addition to 12.1 MMcf of daily pipeline supply.

Under supply plan option B, Holyoke would be able to meet a cold-snap period. However, the Department needs to reassess its cold-snap requirements for 1988/89 and 1989/90 in the next filing. This is discussed <u>infra.</u> in section VII.

E. <u>Summary and Conclusions</u>

The Siting Council's mandated task is to review gas utilities' plans to meet forecasted sendout requirements to ensure <u>adequacy</u>, <u>reliability</u>, and <u>minimum cost</u>, taking into account the variability of sendout due to weather and other considerations. The Siting Council finds Holyoke's plan to meet forecasted sendout requirements during a design year, a cold-snap and peak day to be <u>adequate</u> and <u>reliable</u> for split years 1985/86 through 1987/88.

Given the uncertainty of Bay State LNG and Thomas Corners, the Siting Council cannot make a finding on the adequacy and reliability of the Department's supply plan in the latter years of the forecast period. The Siting Council has concerns about the ability of Holyoke to meet sendout requirements in the latter years of the forecast period should Bay State LNG and/or Thomas Corners not be available. However, there appears to be several alternatives available to meet sendout requirements under normal year, design year, cold-snap and peak day conditions. In its next filing, the Department <u>must</u> address how it will meet sendout requirements in the latter years of the forecast period should Bay State LNG and/or Thomas Corners not be available. Several of the Conditions in this Decision focus on the steps that Holyoke must take to raise the Siting Council's confidence that the Department will have adequate supplies in all years of the forecast period.

On the basis of the evidence in the record before it, the Siting Council cannot find Holyoke's supply plan option B to be least cost.

VII. <u>Impact of Order in Docket No. 85-64</u>

The Siting Council's Order in Docket No. 85-64, along with new Administrative Bulletin No. 86-1, implementing that order, makes some changes in the filing requirements to be met by Massachusetts gas companies in future forecast filings, beginning in 1986. For the Department's convenience, the changes which are most likely to affect its preparation of its next forecast filing are briefly outlined below.

A. Forecast Accuracy

The Siting Council is instituting a requirement that each gas company report on the accuracy of its past forecasts, vis a vis actual normalized sendout for the same years. Holyoke should specifically examine the accuracy of its forecast to determine whether there have been any consistent biases in the 1983, 1984 and 1985 filings. The Department also should determine what factors have considerable impact upon forecast accuracy and specifically address how much of an impact potential inaccurate estimates of customer numbers has upon sendout estimation.

B. Normalization Method

The Order in Docket No. 85-64 requires gas companies to describe in detail and justify their approach to normalization of sendout for weather.

C. Design Year and Peak Day Selection

Administrative Bulletin 86-1 will require the gas companies to provide a rationale for selection of design criteria.

D. New Split Year

On the recommendation of many gas companies, the Siting Council has determined that the split year used for Siting Council reporting purposes should begin in November along with the heating season rather than in April. This change will affect all gas companies, requiring them to recalculate the sendout for each historical base year in their forecast on a one-time basis, as well as to adjust the seasonal degree-day content of the years forming the basis of their normal and design year criteria. The Siting Council recognizes that will cause some inconvenience in preparation of the 1986 forecast, but expects that over the long run the new split year will improve the accuracy and reliability of gas company forecasts.

E. Analysis of Cold-Snap Preparedness

The Order in Docket 85-64 requires that in their next filing, all large-and medium-sized companies must submit either an analysis of their cold-snap preparedness or an explanation of why such an analysis is unnecessary to demonstrate that they will be able to meet their firm sendout obligations throughout a protracted period of design or near-design weather. These explanations of why such an analysis is unnecessary should discuss a company's supply mix, inventory turnover practices, lead time for attaining supplemental supplies, and historical experience of equipment malfunctions, as well as the company's experience in actual historical cold periods.

F. Cost Studies

In the past, the Siting Council's review of a gas company's supply plan has focused primarily on a company's ability to meet the requirements of its firm customers under normal and design weather conditions. In the past, the Siting Council generally has not compared or evaluated the costs of gas supply alternatives.

With a range of supply alternatives currently available at different prices, deliverability levels, and contract terms, the Siting Council must now ensure a gas company's choice of supplies is consistent with the Siting Council's mandate to ensure "a necessary energy supply with a minimum impact on the environment at the lowest possible cost." Mass. Gen. Laws c. 164m sec 69H (emphasis supplied).

In this context, the Siting Council finds that in every forecast filing that indicates that the addition of a long-term firm gas supply contract is proposed within the forecast period, companies are to perform an internal study comparing the costs of a reasonable range of practical supply alternatives. This requirement is intended to cover instances when the following types of contractual arrangements are proposed: (a) changes in amendments to existing firm pipeline supply contracts or new firm pipeline projects; (b) changes in or amendments to firm gas storage contracts and for firm transportation of storage gas or new firm gas storage and/or transportation projects; (c) firm supplies of gas from a producer under a contract covering a two-year period or longer, along with related transportation arrangements; (d) any arrangement for supplemental gas supplies for which the supply is intended for use for a period longer than a single heating season, except for arrangements in which the company can adjust the LNG volumes for the following heating season.

The Thomas Corners underground storage projects, the Tennessee expansion project and the renegotiation with Bay State are sufficient to require Holyoke to prepare a cost study. Since Holyoke has already conducted a cost study, the Department should update its cost study and address the issues discussed supra. in Section V.

VIII. Order and Conditions

The Siting Council APPROVES the 1985 Supplement to the Second Long-Range Forecast of Gas Requirements and Resources of the City of Holyoke Gas and Electric Light Department. Holyoke shall be required to meet the seven conditions listed below.

1. That Holyoke explain and document its knowledge of the community and its use of judgement to adjust the number of customers and use per customers projections. Also, the basis of the adjustment in the number of customers and use per customer should not be limited to conservation.

2. That Holyoke in its next filing describe the method it uses to project number of customers and provide the marketing plans upon which its estimates of number of customers are based.

3. That Holyoke provide a description of the status of its negotiations with Bay State for LNG and submit a contingency supply plan for meeting firm sendout requirements under normal year, design year and peak day conditions.

4. That Holyoke provide a detailed description of the status of the Tennessee expansion and Thomas Corners projects. In particular, the Department should describe the volumes it expects to receive, the in-service dates and any issues still be resolved before deliveries can begin.

5. That Holyoke submit a contingency plan for meeting peak day sendout requirements should Bay State LNG and Thomas Corners not be available for meeting sendout requirements beginning in split-year 1988/1989.

6. That Holyoke satisfy the requirements outlined in the Siting Council's Order in Docket No. 85-64, Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Massachusetts' Natural Gas Utilities, as described in Section VII.

7. That Holyoke's next Supplement is due on October 1, 1986.

Susan F. Tierney

Susan F. Tierney
Hearing Officer

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of August 7, 1986, by the members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation); Stephen Roop (for Secretary James S. Hoyte, Secretary of Environmental Affairs); Joellen D'Esti (for Secretary Joseph D. Alviani, Secretary of Economic Affairs); Joseph Joyce (Public Member, Labor); Dennis LaCroix (Public Member, Gas); and Madeline Varitimos (Public Member, Environment). Ineligible to vote: Elliot Roseman (Public Member, Oil); Stephen Umans (Public Member, Electricity). Absent: Patricia Deese (Public Member, Engineering).

August 22, 1986
Date

Sharon M. Pollard

Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition for Approval of the Wakefield Municipal Light Department's Fourth Supplement to its Second Long-Range Forecast of Gas Requirements and Resources	Docket No. 85-2

FINAL DECISION

Susan F. Tierney
Hearing Officer

On the Decision:

Calvin Young
Staff Analyst
August 7, 1986

The Massachusetts Energy Facilities Siting Council ("Siting Council") hereby APPROVES the Fourth Supplement to the Second Long-Range Forecast of Gas Requirements and Resources ("Supplement") of the Town of Wakefield Municipal Light Department ("Wakefield" or "the Department").[1]

I. INTRODUCTION

The Town of Wakefield Municipal Light Department is a "gas company" as defined under the enabling legislation and the regulations of the Siting Council. Mass. Gen. Laws Ann., Ch. 164, Sec. 69G, Rule 3.3. Wakefield is a small gas system consisting of 4,700 customers spread over 7.5 square miles. Approximately 96 percent of the Department's customers are residential. The Department receives its total gas supply from the Boston Gas Company ("Boston Gas"). Wakefield has no facilities, and does not plan to build or obtain any such facilities during the forecast period.

II. SUMMARY OF THE PROCEEDINGS

Wakefield filed the current supplement on July 1, 1985. A Notice of Adjudication of the 1985 Supplement was issued and duly published in accordance with the Hearing Officer's instructions. As no petitions to intervene or motions to participate as an interested person were filed by the deadline specified in the Notice of Adjudication, this proceeding was left in an uncontested posture.

While consideration of the 1985 Supplement was pending, the Staff issued a Notice of Inquiry into an Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Massachusetts Natural Gas Utilities ("the Notice of Inquiry") in Siting Council Docket No. 85-64. The purpose of the Notice of Inquiry was to solicit comments from all Massachusetts natural gas companies subject to the Siting Council's jurisdiction as to how the Siting Council's review process for gas company forecasts and supply plans could be made more efficient and effective, and its decisions on those forecasts and supply plans more meaningful.

The Notice of Inquiry set forth a large number of specific suggestions for changes in the standards and procedures followed by the Siting Council in gas company forecast and supply plan proceedings. After requesting and receiving written comments on these suggestions from all of the regulated gas companies, the Staff held 10 days of hearings on the Notice of Inquiry in November of 1985. Wakefield

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[1] The Siting Council approved the Third Annual Supplement to the Second Long Range Forecast in October, 1984. Town of Wakefield Municipal Light Department, 11 DOMSC 321 (1984). The Siting Council imposed no conditions in the last decision.

appeared at the hearings on November 19, 1985, and answered numerous questions from the Staff regarding not only the issues raised in the Notice of Inquiry but also the contents of the 1985 Supplement itself. While Wakefield's witnesses did not testify under oath, their comments cast considerable light on certain aspects of the 1985 Supplement. The transcript of that hearing are referred to in this Decision as ("Tr., 11/19/85 at ____"), and will be made a part of the record of this proceeding.

As stated in the Procedural Order of October 22, 1985 in Docket No. 85-64, the present Decision is made on the basis of the Siting Council standards and procedures which prevailed at the time the 1985 Supplement was filed. However, certain applicable changes to those standards and procedures resulting from the Notice of Inquiry and the resultant Order in Docket No. 85-64 are discussed infra, along with suggestions and instructions for their implementation in the 1986 filing.

III. ANALYSIS OF THE SUPPLEMENT

A. Standard of Review

The Commonwealth of Massachusetts mandates that the Siting Council review sendout forecasts of each gas utility to ensure the accurate projection of gas sendout requirements of a utility's market area. The Council's Rules 62.9(2) (a), (b) and (c) require the use of accurate and complete historical data and a reasonable statistical projection method. In its review of a forecast, the Siting Council determines whether a projection method is reasonable according to whether the methodology is: (a) appropriate, or technically suitable for the size and nature of the particular gas utility's system; (b) reviewable, or presented in a way that results can be evaluated and duplicated by another person given the same information; and (c) reliable, that is, provides a measure of confidence that the gas utility's assumptions, judgements and data will forecast what is likely to occur. The Siting Council applies these criteria on a case-by-case basis. Given Wakefield's size and position as an all-requirements customers of Boston Gas, the Siting Council has previously determined that Wakefield need only file a simple "narrative" forecast supplement which focuses on the sendout forecast. In Re Wakefield Municipal Light Department, 4 DOMSC 198 (1979).

In its current forecast, Wakefield has submitted a "narrative" filing and provided tables projecting sendout requirements for all four customer classes, which are space heating, residential non-heating, municipal and commercial, for each year of the forecast period. Wakefield used the same methodology approved by the Siting Council in its Decision on the Department. In Re Wakefield Municipal Light Department, 10 DOMSC 146 (1984).

B. Forecast Methodology

1. Description of Forecast Methodology

Wakefield forecasts requirements for residential non-heating, commercial, and municipal customer classes by determining the average annual use per customer for the previous year and applying a conservation adjustment. The adjusted customer use factor is multiplied

by the projected number of customers, resulting in an annual use estimate for each customer class. Wakefield employs the same basic methodology for space heating customers, except that the average use per customer is broken down into heating and non heating use per customer, and the heating use is normalized.

2. Analysis of Forecast Methodology

Boston Gas's 1984 Supplement provides a forecast of sendout requirement for a normal year for Wakefield which is useful for evaluating the reliability of Wakefield's forecast methodology. See Boston Gas Company, Docket No. 84-25, Supplement Table G-3(c). Table I compares Boston Gas's figures from its 1984 Supplement to those provided by Wakefield in its Table "Form 7" of its 1985 Supplement.

As indicated in Table I, Wakefield's projection of sendout requirements for a normal year exceeds Boston Gas' forecast of sendout requirement for a normal year for each year of the forecast period. However, Boston Gas projects a normal year's sendout requirement to increase at 3.4 percent per annum for 1985/86 through 1988/89, while Wakefield projects its normal year's sendout requirement will increase at 0.3 percent per annum for 1985/86 through 1988/89. Thus, the magnitude by which Wakefield's forecast exceeds Boston Gas' forecast declines from 35.4 MMcf in 1985/86 to 3.9 MMcf in 1988/89.

Wakefield's sendout for 1984/85 was 352.5 MMcf. Normalized sendout for 1984/85 was 360.1 MMcf. In its 1984 Supplement, Wakefield projected sendout to be 339.7 MMcf, a difference of 20.4 MMcf or 5.7 percent. In its 1984 Supplement, Boston Gas projected Wakefield's sendout for a normal year to be 310.6 MMcf -- a difference of 49.5 MMcf or 13.7 percent.

3. Peak Day

As a Condition of its approval of the Department's 1982 Supplement, the Siting Council required Wakefield to provide a forecast of peak day

use for each year of the forecast period. Table II lists Wakefield's computations.

C. Supply: The Boston Gas Contract

Wakefield purchases its total gas supply from Boston Gas on a firm basis. Under the contract, Wakefield may increase its annual purchases from Boston Gas by five percent, on a normalized basis, over the actual purchases made in the preceding year. If the Department exceeds its annual contract amount, it may be subject to a penalty based on the contract's "unauthorized overrun" clause.[2] For contract year 1983-84, the Department's actual take of 352.2 MMcf fell well within its contract limit of 390.2 MMcf. Forecast at 1. As Table I indicates, this contract limit is not projected to constrain Wakefield's gas purchases from Boston Gas in a design year. And Table II indicates that contract limits will not constrain the Departments ability to meet its peak day requirements.

The number of space heating customers has increased by almost 700 customers in the past five years.[3] Contractual constraints prevented Wakefield from expanding more rapidly. Also, the Department would like increase the number of interruptible customers. Therefore, the Department intends to seek changes in its contract with Boston Gas so that (1) Wakefield is able to increase gas purchases by more than five percent per annum in order to add more space heating customers, and (2) to clarify the interruptible customer provisions in its contract to facilitate the acquisition of additional interruptible customers.

The contract will expire in August 31, 1990. The Department intends to begin negotiating a new contract within the next two or three years.[4] Wakefield intends to seek changes in the contract which will permit gas purchases to increase by ten percent and to ad interruptible customers more readily.

D. Summary and Conclusions

The Siting Council finds the Department's methodology to be appropriate for a gas company of Wakefield's size and situation as a total requirements customer of Boston Gas. The forecast was reviewable.

In order to ensure that the required gas is supplied to a utility's customers with a minimum impact on the environment at lowest cost, the Siting Council focuses its supply review on the adequacy, cost and reliability of gas supplies needed to meet projected sendout requirements. The adequacy of supply is measured by the company's ability to meet projected peak day, cold-snap, and total annual firm sendout requirements with sufficient reserves under both normal and design weather conditions. The review of cost of supply addresses cost minimization in concert with notions of adequacy and reliability of natural gas supply. The reliability of supply reviews the likelihood

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[2] A detailed discussion of the provisions of this total requirements contract is found In Re: Wakefield Municipal Light Department, 10 DOMSC 84, 86 (1984).

[3] Tr. 11/19/86, at 13-17.

[4] Ibid. at 14.

Table I

Projected Gas Sendout (MMcf)

	1985/86	1986/87	1987/88	1988/89	1989/90
Contract Limits	409.7	409.7	451.7	474.3	498.0
Wakefield's Design Year Forecast	375.7	375.7	379.4	381.2	382.9
Wakefield's Normal Year Forecast	357.6	358.6	359.6	360.5	361.2
Boston Gas's Forecast for Wakefield's Normal Year Sendout	322.2	333.6	345.2	356.6	-----

that the resources will be available to meet or contribute to meeting firm sendout requirements under normal year, design year, and peak day conditions.

The Siting Council finds that Wakefield's gas supplies from Boston Gas for the forecast period to meet normal, design and peak day sendout requirements are adequate and reliable.

Wakefield should incorporate in the narrative of its next filing a discussion of the number of space heating and interruptible customers it could expect to be able to add, if the company were able to increase its sendout by ten percent per annum. Also, the narrative should describe the impact the additional customers would have upon design year and peak day sendout.

IV. Impact of Order in Docket No. 85-64

A. New Split Year

On the recommendation of many gas companies, the Siting Council has determined that the split year used for Siting Council reporting purposes should begin in November along with the heating season rather than in April. This change will affect all gas companies, requiring them to recalculate the sendout for each historical base year in their forecast on a one-time basis, as well as to adjust the seasonal degree-day content of the years forming the basis of their normal and design year criteria. The Siting Council recognizes that will cause some inconvenience in preparation of the 1986 forecast, but expects that over the long run the new split year will improve the accuracy and reliability of gas company forecasts.

B. Tables

Small Companies are required to file only four tables in its forecasts or supplements: Table G-5, Total Firm Company Sendout; Table

Table II

DESIGN YEAR PEAK DAY

YEAR	HEATING (MCF)	NON-HEATING (MCF)	TOTAL (MCF)	CONTROL LIMIT
1985/86	2,371.6	467.2	2,838.8	3,829
1986/87	2,388.3	466.5	2,854.79	4,020
1987/88	2,404.3	465.7	2,870.0	4,221
1988/89	2,419.5	464.7	2,884.2	4,433
1989/90	2,433.4	463.8	2,897.2	4,654

G-225, Small Companies' Comparison of Resources and Requirements - Normal and Design Heating Season; Table G-23, Comparison of Resources and Requirements - Peak Day; and Table -24, Agreements for Gas Supply.

V. Decision and Order

The Siting Council hereby APPROVES without conditions the Fourth Supplement to the Second Long-Range Forecast of the Town of Wakefield Municipal Light Department. The Third Long-Range Forecast is due on November 1, 1986.

Energy Facilities Siting Council

by Susan F. Tierney
Susan F. Tierney
Hearing Officer

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of August 7, 1986, by the members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of ENergy Resources); Sarah Wald (for Paul W. Gold, Secretary of Consumer Affairs and Business Regulation); Stephen Roop (for Secretary James S. Hoyte, Secretary of Environmental Affairs); Joellen D'Esti (for Secretary Joseph D. Alviani, Secretary of Economic Affairs); Joseph Joyce (Public Member, Labor); Dennis LaCroix (Public Member, Gas); and Madeline Varitimos (Public Member, Environment). Ineligible to vote: Elliot Roseman (Public Member, Oil); Stephen Umans (Public Member, Electricity). Absent: Patricia Deese (Public Member, Engineering).

August 14, 1986
Date

Sharon M. Pollard
Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS

Energy Facilities Siting Council

In the Matter of the Petition of Fitchburg Gas and Electric Light Company for Approval to the Fourth Supplement to the Second Long-Range Forecast of Natural Gas Requirements and Resources	Docket 85-11(A)

Final Decision

Susan F. Tierney
Hearing Officer

On the Decision:
Steven E. Oltmanns

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The Energy Facilities Siting Council ("Siting Council") hereby APPROVES subject to CONDITIONS the Fourth Supplement to the Second Long-Range Forecast of natural gas requirements and resources of the Fitchburg Gas and Electric Light Company ("Fitchburg" or "the Company"). This supplement covers Fitchburg's projections through the 1989-90 split-year.

The Company's Fourth Supplement is essentially the same as the previous supplement in terms of the methodology used to project sendout requirements. Based on this, the Siting Council's decision in this proceeding is brief, and focuses only on selected aspects of the Company's sendout forecast and supply plan.

I. INTRODUCTION

A. Procedural History

The Company filed the Fourth Supplement to its Second Long-Range Forecast of natural gas requirements and resources on November 1, 1985. A Notice of Adjuducation of the Supplement was issued and was published in accordance with the Hearing Officer's instructions. No petitions to intervene or motions to participate as an interested person were filed.

While consideration of the Supplement was pending, the Siting Council Staff issued a Notice of Inquiry into an Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Massachusetts Natural Gas Utilities ("the Notice of Inquiry") in Siting Council Docket No. 85-64. The purpose of this Notice of Inquiry was to solicit comments from all of the Massachusetts natural gas companies under the Siting Council's jurisdiction concerning the Siting Council's decisions on those forecasts more meaningful to those companies.

The Notice of Inquiry established specific suggestions for changes in the standards and procedures to be followed by the Siting Council in gas company forecast proceedings. After requesting and receiving written comments on these suggestions, the Siting Council Staff held 10 days of hearings on the Notice of Inquiry in November, 1985. On November 21, 1985, Fitchburg appeared before the Siting Council Staff at the hearing to answer questions regarding issues raised in the Notice of Inquiry and the content of its current Supplement. Fitchburg's responses are referred to in this Decision (as "Tr., 11/21/85, at ___").

As stated in the Procedural Order of October 22, 1985 in Docket No. 85-64, the present Decision is made on the basis of the Siting

Council standards and procedures which prevailed at the time the Supplement was filed. However, certain applicable changes to those standards and procedures evolving from the Notice of Inquiry are discussed in Section VII, infra, in addition to suggestions and instructions for Fitchburg's implementation of those standards and procedures in its 1986 forecast filing.

B. Record

The record in this Decision consists of the Supplement and the transcript of the November 21, 1985, hearing on the Notice of Inquiry in Siting Council Docket No. 85-64.

II. BACKGROUND

The Company serves approximately 15,167 firm customers in the towns Fitchburg, Ashby, Townsend, Westminster, and Gardner. The largest customer class is the residential-with-gas-heating class with 10,500 customers, followed by the residential-without-gas-heating class with 3,600 customers, the commercial class with 970 customers, and the industrial class with 97 customers. (See Supplement, Tables G-1 through G-5.)

Fitchburg has contracts with Tennessee Gas Pipeline Company ("Tennessee") and Bay State Gas Company ("Bay State") as its major sources of supply over the five-year forecast period. Fitchburg also is a participant in Phase 2 of the Boundary Gas Project. The Company also has long-term storage contracts with Hopkinton LNG Corporation ("Hopkinton"), Consolidated Gas Supply Corporation ("Consolidated"), and Penn-York Storage Corporation ("Penn-York"). Fitchburg's storage contracts with Petrolane Corporation ("Petrolane") and Gas Supply, Inc. ("Gas Supply") expired on March 31, 1986, and its contract with Hopkinton expired on May 1, 1986. (See Supplement, Table G-24.)

Fitchburg's total actual firm sendout in the 1984-85 split year was 2,321.8 MMcf, a 1.57-percent increase from 2,286 MMcf in the 1983-84 split year. Total normalized firm sendout also increased slightly, from 2,303.5 MMcf in 1983-84 to 2,376.3 MMcf in 1984-85, an increase of 3.16 percent. (See Supplement, Table G-5.)

Table 1 shows the forecast of sendout by customer class for the heating and non-heating seasons in split-years 1985-86 and 1989-90. (See Supplement, Tables G-1 through G-5.) Normalized sendout is projected to increase in all four service classes, the industrial class showing the greatest average annual rate of increase at 2.81 percent. The commercial class follows, growing at an average annual rate of 2.70, percent followed by the residential nonheating class at

TABLE 1

Forecast of Sendout by Class

Normal Year

Customer Class	1985 - 86 Nonheating Season (MMcf)	1985 - 86 Heating Season (MMcf)	1985 - 86 Percentage of Annual Firm Sendout (%)	1989 - 90 Nonheating Season (MMcf)	1989 - 90 Heating Season (MMcf)	1989 - 90 Percentage of Annual Firm Sendout (%)
Residential Heating	413.0	873.0	52.4	451.0	954.0	51.4
Residential Nonheating	65.0	73.0	5.6	73.0	81.0	5.6
Commercial	154.0	295.0	18.3	175.0	338.0	18.8
Industrial	155.0	228.0	15.6	177.0	263.0	16.1
Company Use and Unaccounted For	17.0	181.0	8.1	19.0	202.0	8.1
Total Firm Sendout	804.0	1650.0	100.0	895.0	1838.0	100.0
Interruptible	500.0	100.0	-	500.0	100.0	-
Total Sendout	1304.0	1750.0	-	1395.0	1938.0	-

Source: Supplement, Tables G-1 through G-5.

2.22 percent and finally by the residential heating class, at 1.79 percent. Total normalized firm sendout for the total split year is expected to grow annually at 1.76 percent.

The Company has stated that it has re-evaluated its growth rate in the current Supplement. During the previous two years, Fitchburg has maintained a "no-growth" policy due to peak day supply limitations. The Company's aggressive marketing program during the late 1970's and early 1980's increased Fitchburg's peak day sendout to approximately 19,500 MMBtu (19,024.4 MMcf). With peak day capability of 22,700 MMBtu (22,146.3 MMcf), the Company decided in 1982 to add no additional load that would increase peak day sendout until additional firm pipeline supplies could be obtained. Fitchburg is now receiving additional firm pipeline supplies on a daily basis of 10,955 MMBtu/day (10,688 Mcf/day) raising its peak day capability to 25,200 MMBtu (24,585 Mcf). (See Supplement, at 1,2.)

The Company's new stated goal is to market 70,000 MMBtu (68,292.7 Mcf) per year during the forecast period. The average annual rate of growth over the five-year forecast period is approximately 2.85 percent. (See Supplement, at 14.)

III. PREVIOUS CONDITIONS

The Siting Council imposed four conditions in its last decision on Fitchburg's Third Supplement to its Second Long-Range Forecast. In Re Fitchburg Gas and Electric Light Company, 12 DOMSC 173 at 195 (1985).

1) Fitchburg shall include in its next Supplement the results of its marginal cost study and a discussion of the status of development of conservation and load management programs. The discussion shall include a comparison of the cost-effectiveness of conserved gas versus other gas supplies and a justification of the method of comparison.

2) Fitchburg shall present a detailed discussion with back-up statistical documentation justifying reliance on full storage volumes during heating seasons.

3) Fitchburg shall present a cold snap analysis reflecting realistic weather conditions which contains a discussion of the selected standard, the duration of the cold snap, the degree days in the cold snap, and the role of supplementals including trucking, storage, and operation of facilities.

4) Fitchburg shall meet with the Siting Council Staff to discuss improvements to the Company's sendout methodology.

With respect to Condition One, the Company has stated that due to severe financial problems during the first three quarters of 1985, it was unable to complete the study as required by the Massachusetts Department of Public Utilities. Fitchburg asked the Department for a six month extension, and received it. The Company stated that when this study is complete, it would provide a copy to the Siting Council. (See Supplement, Condition Responses at 1.) As a result, the Siting Council reimposes Condition One and ORDERS the Company to include in its next Supplement the results of its marginal cost study and a discussion of the status of development of conservation and load management programs as stated supra. (See Section VIII.)

Regarding Condition Two, Fitchburg has provided a brief narrative to justify reliance on full storage volumes during the heating season. The Company feels that underground storage provides it with two beneficial functions. First, underground storage provides a mechanism for the Company to maintain an increased load factor with injection into storage during the non-heating season. Second, injections into storage plus interruptible loads helps the Company to avoid minimum bill provisions of the Tennessee Tariff. During the heating season, underground storage volumes provide an economical and reliable service of supply to meet increased temperature-sensitive loads. Fitchburg relies on full use of storage volumes during normal and design heating seasons, and plans to increase its underground storage capacity and transportation of those storage volumes on a firm basis. Fitchburg stated that as of December 15, 1985, storage capacity will be increased from 186,257 Mcf to 350,000 Mcf (an increase of 87.9 percent) with firm transportation for this increase. In addition, Fitchburg's maximum daily quantity ("MDQ") will be increased from 7,506 Mcf to 10,233 Mcf, an increase of 36.3 percent. (See Supplement, Condition Responses at 1.)

The Siting Council concludes that, for Fitchburg, reliance on full storage volumes during the heating season provides for a reliable source of supply and reduced dependence on supplementals. The Siting Council accepts the Company's response to this Condition and has determined that Condition Two has been satisfied.

With regard to Condition Three, Fitchburg provided a detailed cold snap analysis reflecting realistic weather conditions in its service territory. The Company regards a cold snap as a 10-day period of peak day weather conditions based on 21 years of Worcester-Bedford weather data. The historic maximum "cold spell" which Fitchburg uses for planning purposes occured during the period February 9, 1985, through February 18, 1985 and consisted of the following degree days:

Feburary 9	-	55 degree days
February 10	-	64 degree days
February 11	-	65 degree days
February 12	-	59 degree days
February 13	-	63 degree days
February 14	-	61 degree days
February 15	-	55 degree days
February 16	-	59 degree days
February 17	-	64 degree days
February 18	-	54 degree days
Total		599 degree days

Fitchburg's cold snap is based on a total of 600 degree days for a 10 day period, which, when combined with the base load and heating factors which the Company uses to forecast sendout under peak conditions, produces a total required sendout of 175,810 MMBtu (171.52 MMcf). Cold snap requirements would be met by the following sources:

	Average Daily MMBtu	Cold Snap MMBtu
Pipeline	7,847	78,470
Storage	3,262	32,620
LPG	2,157	21,570
LNG	4,315	43,150
Total	17,581	175,810

Those pipeline and storage volumes that would be required in a cold snap represent the maximum contracted volumes which the Company has available. The LNG volumes that would be required for the 10 day period represent an average of 5 trucks per day, which is less than the 7 trucks per day provided for under the existing contract. The LPG volumes required for the 10 day period represent approximately 70 percent of the available storage capacity and could be supplied entirely from existing storage without any additional volumes being trucked into the LPG plant. (See Supplement, Condition Responses at 2.)

The Siting Council is pleased with the documentation and level of detail in its cold snap analysis. Such an analysis is worthy of other natural gas utilities in Massachusetts which are larger than Fitchburg. The Siting Council concludes that Condition Three has been satisfied.

With respect to Condition Four, the Siting Council has waived this Condition due to Fitchburg's participation in the Siting Council's Notice of Inquiry as discussed in Section I. A., supra. The Siting Council Staff had the opportunity to meet with Company personnel to discuss improvements to the its sendout methodology at the hearing held on November 21, 1985.

IV. SENDOUT METHODOLOGY

A. Weather Data

The Company uses weather data for the purpose of forecasting sendout based on a Worcester-Bedford average over a 20-year period. In the current filing, a normal year consists of 6,773 degree days, which is the arithmetic average of degree days from 1964 through 1984 recorded in Worcester and Bedford as provided by Weather Services Corporation. Design year degree days are determined based on a probability of a once-in-fifty-years occurrence using a normal distribution of weather data. This methodology results in a design year of 7,318 degree days. Fitchburg then applies the difference between normal and design year degree days (544 degree days) entirely to the design heating season to further ensure that adequate supplies will be available during a design heating season to meet the criteria established. (See Supplement, at 3.)

In determining peak day degree days, Fitchburg analyzes 21 years of Worcester-Bedford data. The Company bases its 70 degree-day peak day on the actual occurrence of only once in the 21-year period from 1964 through 1985. (See Supplement, at 3.)

B. Customer Use Factors

Fitchburg projects gas sales for four firm customer classes: 1) residential with gas heating, 2) residential without gas heating, 3) commercial, and 4) industrial. The methodology which is used by the Company is unchanged from its last filing. In Re Fitchburg Gas and Electric Light Company, 12 DOMSC 173 at 176 (1985). Fitchburg projects normal year sendout requirements using data from the most recent split year to derive base load and space heating increments for all customer classes for both the non-heating and heating seasons. Fitchburg's design year projections are derived in the same way as for a normal year only using the design weather standards. Both normal and design year sendouts were developed by allocating the targeted annual growth by the percentage contribution that heating season and non-heating season are to total split year. Total forecast sendouts were then allocated to customer classes by percentages that were derived from adjusted 1984-85 historical percentages. (See Supplement, at 14.)

In the residential-with-gas-heating class, Fitchburg calculates split-year base use per customer by dividing August sales data by the number of heating customers in that month to obtain a monthly base load per customer. Monthly base load per customer factors are then multiplied by 12 to obtain split year base use per customer. The split year heating component is determined by subtracting the total base load from total consumption. The space heating component is then divided by the actual degree days and then by the average number of customers to determine split year heating use per customer. (See Supplement, at 7.) For the residential-without-gas-heating class, the split year average use per customer is calculated by taking the split year data and dividing by the average number of customers. (See Supplement, at 8.)

For those customers in the residential-with-gas-heating class, Fitchburg projects constant base use per customer and heating use per customer per degree day factors over the five-year forecast period (30.0 Mcf/customer and 0.0140 Mcf/customer/degree day, respectively). Upon analyzing the historical five-year data base, it can be seen that for those factors the trend has been as follows:

Split Year	Split Year Heating Use Per Per Customer Per Per Degree Day (Mcf)	Split Year Base Use Per Customer (Mcf)
1980 - 81	0.0148	33.5
1981 - 82	0.0143	35.4
1982 - 83	0.0139	34.1
1983 - 84	0.0140	30.9
1984 - 85	0.0140	30.1

The Company's projection of heating use factors over the forecast period appears to be representative of the trend which has been occurring during the last three years. However, the base use factors indicate a downward trend over the past four years with an indication of leveling off in the past two years. (See Supplement, Table G-1.) For those average use per customer factors in the residential-without-gas-heating class, Fitchburg also projects that these factors will remain constant over the five-year forecast period (38.0 Mcf/customer). (See Supplement, Table G-2.)

In its last decision, the Siting Council strongly criticized Fitchburg's methodology for not appropriately linking historical data to future projections. In Re Fitchburg Gas and Electric Light Company, 12 DOMSC 173 at 178 (1985). Again, the historical data on customer base and heating use factors are not used to project future requirements. The Company derives future requirements by a system-wide regression of the actual sendout in the most recent historical split year. It is still not clear to the Siting Council whether the Company's assumption that the relative sendout requirements among customer classes will remain constant is valid without documentation. The Siting Council reiterates its previously mentioned concern that Fitchburg should begin development of a forecast methodology which will allow projections to reflect changing customer usage patterns across and within service classes during the coming period of system growth. The Siting Council ORDERS Fitchburg to provide, in its next Supplement, sufficient documentation to support key assumptions of its methodology in particular with regards to customer use factors remaining constant during the five-year forecast period. Further, the Siting Council requires the Company to justify how its methodology adequately allows the Company to adjust its customer-use projections for known changes in sendout requirements for all classes. (See Section VIII, infra.) Upon reviewing this supportive evidence, the Siting Council will determine whether or not Fitchburg should begin development of a forecast methodology which will allow projections to reflect changing customer usage patterns.

In the commercial class, Fitchburg separates customers into those with gas heating and those without gas heating. Base use and heating factors are calculated in a similar manner as in the residential classes. Base use per customer is calculated by dividing the total of the July and August sales data by the total number of customers in both months. The monthly use is then multiplied 12 and then by the average number of customers to determine split year base use. The space heating component is calculated by subtracting the split year base use from the total sendout. The space heating index per customer is then calculated by dividing the space heating component by the product of the average number of customers and annual degree days. (See Supplement, at 10.)

For the industrial class, Fitchburg also calculates annual consumption for those customers with gas heat and those without gas heat. Annual consumption for customers with and without gas heat is calculated by summing the monthly consumption over the twelve months of the split year for both groups. The percentage of consumption with gas heat was calculated by dividing the annual consumption of those customers with gas heat by total annual sendout. The heating usage for both the non-heating and heating seasons is then obtained by multiplying the percent with gas heat by the non-heating/heating season sendout. The without gas heat usage for both the non-heating and heating seasons is calculated by subtracting the with gas heating useage for the non-heating and heating seasons from the non-heating and heating season sendouts. (See Supplement, at 12.)

The Company's peak day methodology has changed slightly since the previous filing. In the past, the projected annual growth percentage was multiplied by the base year to obtain the projected peak growth. The projected peak growth was then added to the previous peak to obtain the next year projected peak. This methodology is changed by the use of a diversity factor, equal to 0.85. Fitchburg uses the 0.85 diversity factor because it feels that not all future growth will be temperature sensitive, including gas used for potential cogeneration loads and processes. (See Supplement, at 18.) The Siting Council requests that the Company in its next filing, provide supporting documentation to justify the 0.85 value of the diversity factor, to further enhance the reliability of its peak day methodology.

In addition, the peak day methodology does not account for the possibility that heating use patterns may vary according to the degree days experienced. The Siting Council ORDERS Fitchburg to include in its next filing the supporting documentation justifying its assumption that heating use per degree day does not increase during extremely cold days. (See Section VIII, *infra*.) If the Company cannot support this assumption, the Siting Council may require changes in the Company's peak day sendout methodology.

In the current Supplement, Fitchburg does not explicitly consider the impact of conservation on firm sendout. In the past, the Company's forecasts have considered conservation with "varying degrees of importance." (Tr., 11/21/85, at 55.) The Siting Council is concerned with the Company's regard for the impact of conservation on customer use factors and total firm sendout. Because Fitchburg did not provide an explanation of its treatment of conservation in the filing, the Siting Council ORDERS the Company to provide in its next filing a narrative description of why the effects of conservation were or were not included in its forecast of customer use factors and total firm sendout, and if conservation effects are included, how the Company treats them methodologically. (See Section VIII, *infra*.)

Company use and unaccounted-for gas is, on average, 2.09 percent of total firm sales in the non-heating season and 11.0 percent of total firm sales in the heating season over the five-year forecast period. Company use and unaccounted for gas is combined with the sendout in each of the four customer classes to yield firm sendout.

The Siting Council acknowledges improvements in Fitchburg's forecast methodology, particularly with respect to the level of documentation. However, the Company's treatment of customer use factors and conservation are two areas where the Company is still deficient. The Siting Council requires Fitchburg to address these issues in its next filing by complying with the CONDITIONS as described in Section VIII, *infra*.

C. Customer Projections

The Company projects customer numbers based primarily on the level of supplies available in the forecast period. Total forecasted sendouts, developed with targeted annual market growth rates, are allocated to customer classes by percentages that were derived from 1984-85 split-year data. (See Supplement, at 14.)

Fitchburg projects that the average number of residential gas heating customers will grow from 10,546 in 1985-86 to 11,718 in 1989-90, an average annual rate of growth of approximately 2.13 percent. This translates into an increase in customer numbers of 293 in each split year of the five-year forecast. The rate of growth is slightly less than what was experienced over the five-year historical period, where the annual growth rate was approximately 2.39 percent. (See Supplement, Table G-1.)

The residential-without-gas-heating class is also projected to show an increase in customer numbers, from 3,624 in 1985-86 to 4,037 in 1989-90. (See Supplement, Table G-2.) The average annual rate of growth is approximately 2.18 percent, which is very close to the growth rate in the residential heating class. Historically, customer numbers in the residential-without-gas-heating class have declined annually by 1.48 percent. Since the Company did not provide an explanation for why its projected growth rates for customer numbers are a departure from recent historical trends, the Siting Council can only conjecture as to the reasons. If situations such as this should occur in the future, the Company should provide explanations and/or supporting documentation as part of its filing with the Siting Council.

The commercial class is projected to show the lowest growth rate of all the service classes. Commercial customer numbers are projected to increase from 975 in 1985-86 to 1,015 in 1989-90, an average annual rate of growth of 0.81 percent or the addition of 10 customers per year over the forecast period. (See Supplement, Table G-3 (A).) In the past five years, the annual growth rate in the number of commercial customer numbers has been much greater (2.16 percent) than it is projected to be in the five-year forecast period.

Finally, industrial customer numbers are also projected to increase by 2 customers per year over the forecast period. Fitchburg projects industrial customer numbers to increase from 97 in 1985-86 to 105 in 1989-90, an average annual rate of growth of approximately 1.60 percent. (See Supplement, Table G-3 (B).) However, in the previous five years the number of industrial customers has been declining annually by approximately 0.62 percent.

The Siting Council urges Fitchburg to include in its narrative description of customer number projections a brief explanation of why future projections are in certain situations contrary to what has been occuring in its service territory. Specifically, the Company should explain why it feels its marketing information concerning the future justifies these growth trends when historical trends in customer numbers are contradictory.

V. RESOURCES AND FACILITIES

The Company has contracts with Tennessee and Bay State for providing the major sources of supply over the forecast period. The contracts with Tennessee expire in the year 2000, and with Bay State in 1988. Fitchburg also has contracts with Consolidated and Penn-York for providing storage service, both of which contracts expire in the year 2000. (See Supplement, Table G-24.) Fitchburg is also a participant in the pending Phase 2 Boundary Gas Project.

The Siting Council supports Fitchburg's apparent move toward reliance upon lower cost pipeline gas and away from more expensive supplementals. Fitchburg has a precedent agreement with Tennessee to increase the Company's maximum daily quantity ("MDQ") pipeline volumes. The current annual volumetric limitation ("AVL") of 2,800 MMcf, however, would not change. Tennessee has applied to the Federal Energy Regulatory Commission ("FERC") as part of a current AVL project to increase the firm supplies of CD-6 gas to distribution customers. Tennessee Gas Pipeline Company, FERC Docket No. CP84-441-002. Tennessee has applied to increase the Company's MDQ from 7,506 Mcf to 10,246 MMBtu (8,196.8 Mcf) per day. (See Supplement, at 2.) Final approval of this increase is still pending. The Siting Council requests that Fitchburg provide an update in its next filing on the progress being made to firm up additional volumes on a daily basis.

Fitchburg is a party to a precedent agreement for Canadian Gas as part of Phase 2 of the Boundary Gas Project ("Boundary"). It has become evident that Boundary service will not commence by the originally estimated 1986 in-service date. As a result, Tennessee has filed an application with FERC for authorization to provide interim sales of natural gas to Boundary customers until the facilities necessary to import gas from Canada are constructed. Tennessee would sell gas to those customers at their CD-5 and CD-6 rate schedules. This project, known as Interim Natural Gas Service or "INGS", is pending FERC approval. (FERC Docket No. CP86-251.) Fitchburg anticipates volumes of 530 Mcf per day (193.4 BBtu per year) through this service beginning in November, 1987. (See Supplement, at 2.) The Siting Council requests that Fitchburg, in its next filing and until Phase 2 of the Boundary Project is in service, provide an updated report on its involvement in the interim service and subsequent phases of the project. The Company should also include in its next filing a contingency plan that Fitchburg would implement if the final Phase 2 project is delayed beyond November, 1988.

Fitchburg receives liquefied natural gas ("LNG") by displacement transportation provided by Tennessee. The Company's contract with Bay State is for 250 BBtu (243.9 MMcf) per year. Fitchburg has an option to take an additional 75 BBtu (73.2 MMcf) per year on an optional basis if required. (See Supplement, Table G-24.) These volumes have not changed since the Company's previous filing. At that time, Fitchburg stated that a reduction in Bay State LNG volumes before 1988 would only be possible if and when firm transportation of underground storage were increased or an increased MDQ were approved. In Re Fitchburg Gas and Electric Light Company, 12 DOMSC 173 at 183 (1985). As discussed infra, firm transportation of underground storage has been approved and, as discussed supra, the Company has a precedent agreement with Tennessee to increase its MDQ. The Siting Council therefore encourages Fitchburg continue monitoring its LNG purchases and to reduce them to the extent consistent with considerations of reliability and economy.

Distrigas of Massachusetts Corporation ("DOMAC") is a major supplier of LNG to Bay State. Distrigas Corporation ("Distrigas"), the parent company of DOMAC, has filed for bankruptcy thus creating uncertainty about the reliability of DOMAC as a source of supply. In a recent decision, the Siting Council questioned the reliability of LNG supplied by DOMAC. In Re Bay State Gas Company, 14 DOMSC ___ at 26 (1986). Since Fitchburg includes LNG volumes from Bay State in its supply plan, and the reliability of supply of LNG to Bay State from DOMAC is uncertain, the Siting Council regards the reliability of Bay State LNG supply as uncertain. Because of this uncertainty, the Siting Council ORDERS Fitchburg to include in its next filing a contingency plan for LNG. The discussion shall include: the status of the Distrigas and DOMAC federal government applications; the impact of Order No. 380 on DOMAC's ability to supply Bay State with LNG and the resultant capability of Bay State to supply Fitchburg with LNG; and identification of other potential suppliers of LNG, and possible terms of delivery. (See Section VIII, infra.)

Fitchburg's existing contract with Consolidated for storage service is for less volumes than its previous contract, which expired on March 31, 1986. Currently, the Company has contracted for storage of 51.3 BBtu (50.0 MMcf) per year. The storage service contract which the Company has with Penn-York is for 139.0 BBtu (135.6 MMcf) per year. (See Supplement, Table G-24.)

Fitchburg began to receive additional pipeline transportation of storage gas on a firm basis in December, 1985. The Company is now receiving an additional 2,727 Mcf per day by Tennessee from those volumes stored at Penn-York and Consolidated. Combining the firm transportation of these storage volumes with the proposed increase in the Company's MDQ from Tennessee described above will increase Fitchburg's peak day capability from 22,700 MMBtu (22,146.3 Mcf) to approximately 35,446 MMBtu (32,091.4 Mcf), assuming the MDQ increase is approved. (See Supplement, at 2.)

The Company leases on-site storage LNG storage and vaporization facilities in Westminster. This facility is capable of storing 4.17 MMcf and peak day sendout capacity of 7.2 MMcf per day. Fitchburg also has propane/air peak shaving facilities located in Lunenburg capable of storing 30.4 MMcf and vaporizing 7.2 MMcf per day. (See Supplement, Table G-14.)

In terms of planned or proposed facilities, Fitchburg has indicated that with the potential of increased pipeline deliveries to a level of approximately 13,300 Mcf per day by the 1987 heating season, system improvements may be required to move that volume of gas through its present take station. To improve the reliability of the existing system and increase its market share in the Gardner area, Fitchburg would propose to construct a 10-inch high pressure pipeline loop between Fitchburg and Gardner 9.65 miles in length with a maximum operating pressure of 150 pounds per square inch. (See Supplement, Table G-21.) The pipeline would constitute a "facility" under Mass. Gen. Laws Ann. and would require the Siting Council's approval prior to construction. The Company should present to the Siting Council a formal filing regarding this proposed facility if the expected increases in pipeline supplies are approved as the Company expects and if the Company still anticipates that a looping project would be required to accomodate the increased volumes.

VI. COMPARISON OF RESOURCES AND REQUIREMENTS

In past reviews of companies' supply plans, the Siting Council has focused primarily on a gas company's ability to meet the requirements of its firm customers during peak day, normal and design weather conditions. With few exceptions, the Siting Council has not compared the costs of gas supply alternatives.

The Siting Council recognizes that a company's supply planning process is continuous, and that tradeoffs may exist between the reliability, cost and environmental impacts of different supply sources. Further, the Siting Council recognizes that a company's supply decisions are based on the information available and supply situation existing at the time the company's management makes the decisions. Thus, each company's supply plan will be different, and the Siting Council will attempt to recognize the unique factors affecting the particular company under review. In the future, the Siting Council will attempt to review each company's basis for selecting a supply alternative or the company's decision-making process for selecting that supply to ensure that the company's decisions are based on projections founded on accurate historical information and sound projection methods.

In reviewing Fitchburg's current Forecast Supplement, the Siting Council has examined, as before, the adequacy of Fitchburg's supplies to meet firm requirements under normal and design weather conditions, and peak day and cold snap conditions. The Siting Council in general is satisfied that Fitchburg has sufficient supplies under these conditions. The record in the instant proceeding is insufficient to enable the Siting Council to judge whether the Company's plan ensures an adequate supply at the lowest possible cost. To address this lack of information in future filings, the Siting Council will require the Company to perform cost studies. (See Section VII, infra.)

The Company stated that it does not anticipate receiving Boundary volumes before November 1, 1987. In fact, for planning purposes, Fitchburg did not include these volumes in its supply plan until the 1988-89 split year. As discussed in Section V supra, the Siting Council requests that Fitchburg, in its next filing and until Phase 2 of the Boundary Project is in service, provide an updated report on its involvement in the interim service and subsequent phases of the project. The Company should also include in its next filing a contingency plan that Fitchburg would implement if the final Phase 2 project is delayed beyond November, 1988.

A. Normal Year

In a normal year, Fitchburg must have adequate supplies to meet several types of requirements. Most importantly, Fitchburg must meet the requirements of its firm customers. Second, the Company must insure that its underground storage facilities are filled prior to the start of the heating seaon. To the extent possible, Fitchburg also supplies gas to its interruptible customers. Tables 2 and 3 present a comparison of resources and requirements for the normal year non-heating and heating seasons, respectively. As indicated, Fitchburg plans to meet its normal year requirements and the small amount of heating-season sales to interruptible customers with Tennessee CD-6 pipeline gas, stored and purchased LNG and stored and purchased propane. Assuming full storage of supplementals and the firm storage return from Tennessee, Fitchburg has adequate resources available to it to meet system requirements under normal year conditions, on a seasonal basis, throughout the five-year forecast period. In addition, the Company appears to be improving the reliability of its supplies through increased Penn-York storage gas transportation and its request to increase its MDQ of Tennessee CD-6 gas.

B. Design Year

During a design year, Fitchburg must have sufficient gas supplies

TABLE 2

Comparison of Resources and Requirements

(MMcf)

Normal Year - Nonheating Season

Requirements	1985 - 86	1986 - 87	1987 - 88	1988 - 89	1989 - 90
Normal Firm Sendout	804.0	827.0	850.0	873.0	895.0
Interruptibles	500.0	500.0	500.0	500.0	500.0
Fuel Reimbursement	0.0	0.0	0.0	4.0	4.0
Storage Refill					
- Underground	317.0	358.0	358.0	358.0	358.0
- Propane	28.0	28.0	28.0	28.0	28.0
- Liquefaction	20.0	0.0	0.0	0.0	0.0
- LNG Purchases	4.0	4.0	4.0	4.0	4.0
Total	1673.0	1717.0	1740.0	1767.0	1789.0

Resources	1985 - 86	1986 - 87	1987 - 88	1988 - 89	1989 - 90
TGP CD-6	1635.0	1627.0	1481.0	1508.0	1461.0
TGP Interruptible	0.0	52.0	226.0	171.0	240.0
Boundary*	0.0	0.0	0.0	55.0	55.0
Firm LNG Purchases	10.0	10.0	5.0	5.0	5.0
Spot LPA Purchases	28.0	28.0	28.0	28.0	28.0
Total	1673.0	1717.0	1740.0	1767.0	1789.0

* Boundary Interim Service proposed to be provided by Tennessee Gas Pipeline.

Source: Supplement, Table G-22N.

TABLE 3

Comparison of Resources and Requirements

(MMcf)

Normal Year - Heating Season

Requirements	1985 - 86	1986 - 87	1987 - 88	1988 - 89	1989 - 90
Normal Firm Sendout	1650.0	1698.0	1744.0	1791.0	1838.0
Interruptibles	100.0	100.0	100.0	100.0	100.0
Fuel Reimbursement	9.0	16.0	16.0	20.0	20.0
Total	1759.0	1814.0	1860.0	1911.0	1958.0

Resources					
TGP CD-6	1058.0	1107.0	1253.0	1226.0	1273.0
TGP Interruptible	0.0	100.0	0.0	0.0	0.0
TGP Storage Return (Firm)					
- Consolidated	219.0	51.0	51.0	51.0	51.0
- Penn-York	98.0	307.0	307.0	307.0	307.0
Boundary*	0.0	0.0	0.0	78.0	78.0
Stored LNG	24.0	4.0	4.0	4.0	4.0
Firm LNG Purchases	240.0	125.0	125.0	125.0	125.0
Stored Propane	28.0	28.0	28.0	28.0	28.0
Firm Propane Purchases	92.0	92.0	92.0	92.0	92.0
Total	1759.0	1814.0	1860.0	1911.0	1958.0

* Boundary Interim Service proposed to be provided by Tennessee Gas Pipeline.

Source: Supplement, Table G-22N.

to meet the sendout requirements of its temperature-sensitive-use customers above normal-year requirements. Tables 4 and 5 compare resources and requirements for the non-heating and heating seasons for a design year, respectively.

In a design non-heating season, Fitchburg does not anticipate its requirements to exceed those in a normal heating season. The Company expects the identical firm sendout, sales to interruptible customers and storage refill requirements as in a normal year non-heating season. Fitchburg has sufficient supplies available to meet sendout requirements in a design non-heating season. If necessary, the Company can reduce its interruptible sales (500.0 MMcf) until its underground storage is at capacity. In a design heating season, Fitchburg will rely not only on Tennessee CD-6 pipeline gas, stored and purchased LNG and stored and purchased propane to meet its requirements but also on spot market propane purchases and optional LNG volumes from Bay State. Again assuming full storage of supplementals and the firm storage return from Tennessee, Fitchburg has adequate resources available to it to meet system requirements under design year conditions, on a seasonal basis, throughout the five-year forecast period. However, as discussed supra, the Siting Council regards the reliability of those LNG volumes from Bay State as uncertain. In addition, the Siting Council considers Fitchburg's reliance on spot propane purchases during a design winter to be risky in nature, even though it is possible that such purchases could be made during some portions of the heating season.

C. Peak Day and Cold Snap

Fitchburg must have adequate sendout capacity to meet the requirements of its firm customers on a peak day. While total supply available for normal and design year requirements is a function of the aggregate volumes of gas available over some contract period, peak day sendout is a sum of the maximum rate of firm gas deliveries that a company is capable of taking and dispatching in a single day, and the maximum rate of dispatching from stored supplementals. Table 6 presents the comparison of resources and requirements throughout the five-year forecast period for peak day conditions. It is clear that Fitchburg has more than adequate resources available to meet its peak day requirements, again assuming full storage of supplementals and Tennessee storage return. Fitchburg could still meet its peak day requirements without the proposed Tennessee MDQ increase, or without those volumes from the Boundary project. In the event of multiple contingencies, however, Fitchburg would require more reliance on supplementals.

The Siting Council has defined a cold snap as a prolonged series of days at or near peak conditions. The Company's ability to meet requirements during such a cold snap is related to both its ability to

TABLE 4

Comparison of Resources and Requirements

(MMcf)

Design Year - Nonheating Season

Requirements	1985 - 86	1986 - 87	1987 - 88	1988 - 89	1989 - 90
Design Firm Sendout	804.0	827.0	850.0	873.0	895.0
Interruptibles	500.0	500.0	500.0	500.0	500.0
Fuel Reimbursement	0.0	0.0	0.0	4.0	4.0
Storage Refill					
- Underground	317.0	358.0	358.0	358.0	358.0
- Propane	28.0	28.0	28.0	28.0	28.0
- Liquefaction	20.0	0.0	0.0	0.0	0.0
- LNG Purchases	4.0	4.0	4.0	4.0	4.0
Total	1673.0	1717.0	1740.0	1767.0	1789.0

Resources					
TGP CD-6	1635.0	1584.0	1435.0	1462.0	1415.0
TGP Interruptible	0.0	95.0	272.0	217.0	286.0
Boundary*	0.0	0.0	0.0	55.0	55.0
Firm LNG Purchases	10.0	10.0	5.0	5.0	5.0
Spot Propane Purchases	28.0	28.0	28.0	28.0	28.0
Total	1673.0	1717.0	1740.0	1767.0	1789.0

* Boundary Interim Service proposed to be provided by Tennessee Gas Pipeline.

Source: Supplement, Table G-22D.

TABLE 5

Comparison of Resources and Requirements

(MMcf)

Design Year - Heating Season

Requirements	1985 - 86	1986 - 87	1987 - 88	1988 - 89	1989 - 90
Design Firm Sendout	1796.0	1843.0	1890.0	1937.0	1984.0
Fuel Reimbursement	9.0	16.0	16.0	20.0	20.0
Total	1805.0	1859.0	1906.0	1957.0	2004.0

Resources					
TGP CD-6	1099.0	1150.0	1299.0	1272.0	1319.0
TGP Interruptible	5.0	50.0	0.0	0.0	0.0
TGP Storage Return (Firm)					
- Consolidated	219.0	51.0	51.0	51.0	51.0
- Penn-York	98.0	307.0	307.0	307.0	307.0
Boundary*	0.0	0.0	0.0	78.0	78.0
Stored LNG	24.0	4.0	4.0	4.0	4.0
Firm LNG Purchases	240.0	125.0	125.0	125.0	125.0
LNG Optional Volumes	0.0	26.0	0.0	0.0	0.0
Stored Propane	28.0	28.0	28.0	28.0	28.0
Firm Propane Purchases	92.0	92.0	92.0	92.0	92.0
Spot Propane Purchases	0.0	26.0	0.0	0.0	0.0
Total	1805.0	1859.0	1906.0	1957.0	2004.0

* Boundary Interim Service proposed to be provided by Tennessee Gas Pipeline.

Source: Supplement, Table G-22D.

TABLE 6

Comparison of Resources and Requirements

(MMcf)

Peak Day

Requirements	1985 - 86	1986 - 87	1987 - 88	1988 - 89	1989 - 90
Forecasted Sendout	20.8	21.2	21.7	22.2	22.6
Resources					
TGP CD-6	7.8	7.8	8.8	10.8	10.8
TGP Storage	3.2	3.2	3.2	3.2	3.2
Propane	7.2	7.2	7.2	7.2	7.2
Vaporized LNG	7.2	7.2	7.2	7.2	7.2
Boundary*	0.0	0.0	0.0	0.5	0.5
Total	25.4	25.4	26.4	28.9	28.9

* Boundary Interim Service proposed to be provided by Tennessee Gas Pipeline.

Source: Supplement, Table G-23.

meet design heating seaon requirements and its ability to meet peak day sendout requirements. As in planning to meet design heating season requirements, the 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. Further, it is similar to peak day in that the Company must show that it has and can sustain the ability to deliver large daily volumes.

As discussed earlier in Section III, supra, Fitchburg provided a detailed cold snap analysis reflecting realistic weather conditions in its service territory. Fitchburg's cold snap is based on a total of 600 degree days for a 10 day period, which, when combined with the base load and heating factors the Company uses to forecast sendout under peak conditions, produces a total required sendout of 175,810 MMBtu (171.52 MMcf). Pipeline and storage volumes that would be required in a cold snap represent the maximum contracted volumes which the Company has available. The LNG volumes that would be required for the 10 day period represent an average of 5 trucks per day, which is less than the 7 trucks per day provided for under the existing contract. The propane volumes required for the 10 day period represent approximately 70 percent of the available storage capacity and could be supplied entirely from existing storage without any additional volumes being trucked into the LPG plant. (See Supplement, Condition Responses at 2.) The Siting Council concludes that Fitchburg is well prepared to meet the requirements of an extended cold-snap.

VII. IMPACT OF ORDER IN DOCKET NO. 85-64

The Siting Council's Order in Docket No. 85-64, along with new Administrative Bulletin No. 86-1, implementing that order, makes some changes in the filing requirements to be met by Massachusetts gas companies in future forecast filings, beginning in 1986. For the Company's convenience, the changes which are most likely to affect its preparation of its next forecast filing are briefly outlined below.

A. Forecast Accuracy

The Siting Council is instituting a requirement that each gas company report on the accuracy of its past forecasts, vis a vis actual normalized sendout for the same years. If Fitchburg should have difficulty in locating these historical data for inclusion in its filings, it should request assistance from the Siting Council Staff.

B. Normalization Method

The order in Docket No. 85-64 requires gas companies to describe in detail and justify their approach to normalization of weather.

Fitchburg should include in its next filing a detailed description and discussion of its normalization technique as it did in the current filing, including its reasons for using this method.

C. Design Year and Peak Day Selection

Administrative Bulletin 86-1 requires gas companies to provide a rationale for their selection of design criteria. Fitchburg already does this in its description of weather data. (See Supplement, at 3.) Fitchburg bases its design year on a probability of a once-in-fifty-years occurrence using a normal distribution of weather data. This methodology results in a design year of 7,318 degree days. Fitchburg then applies the difference between normal and design year degree days (544 degree days) entirely to the design heating season to further ensure that adequate supplies will be available during a design heating season to meet the criteria established. In determining peak day degree days, Fitchburg analyzes 21 years of Worcester-Bedford data. The Company bases its 70 degree-day peak day on the actual occurrence of only once in the 21-year period from 1964 through 1985. To meet this requirement, Fitchburg will be required only to resubmit the type of information provided in the 1985 filing in its next filing with a rationale for selecting criterion and for applying the statistical method of normal distribution.

D. New Split Year

On the recommendation of many gas companies, the Siting Council has determined that the split year used for Siting Council reporting purposes should begin in November, along with the heating season, rather than in April. This change will affect all gas companies, requiring them to recalculate the sendout for each historical base year in their forecast on a one-time basis, as well as to adjust the seasonal degree day content of the years forming the basis of their normal and design-year criteria. The Siting Council recognizes that this will cause some inconvenience in the prepration of the 1986 forecast, but expects that over the long run the new split year will improve the accuracy and reliability of gas company forecasts.

E. Analysis of Cold Snap Preparedness

The order in Docket No. 85-64 requires that in their next filings, all large- and medium-sized companies must submit either an analysis of their cold snap preparedness or an explanation of why such an analysis is unnecessary to demonstrate that they will be able to meet their firm sendout obligations throughout a protracted period of design or near-design weather. These explanations should discuss a company's supply mix, inventory turnover practices, lead time for attaining supplemental supplies, and historical experience of equipment malfunctions, as well as the company's experience in actual historical cold periods. Fitchburg has already included much of this information in the cold snap analysis which it supplied in the current filing. (See Supplement, Condition Responses at 2.) To meet this requirement, Fitchburg will be required only to include in its cold snap analysis those historical experiences in actual cold periods and equipment malfunctions as described above and to include the completed analysis in its next filing.

F. Cost Studies

In the past, the Siting Council's review of a gas company's supply plan has focused primarily on the company's ability to meet the requirements of its firm customers under normal and design weather conditions. In the past, the Siting Council generally has not compared or evaluated the costs of gas supply alternatives.

With a range of supply alternatives currently available at different prices, deliverability levels, and contract terms, the Siting Council must now ensure a gas company's choice of supplies is consistent with the Siting Council's mandate to ensure "a necessary energy supply with a minimum impact on the environment at the lowest possible cost." Mass. Gen. Laws ch. 164, sec. 69H (emphasis supplied).

In this context, the Siting Council finds that in every forecast filing that indicates the addition of a long-term firm gas supply contract is proposed within the forecast period, companies are to perform an internal study comparing the costs of a reasonable range of practical supply alternatives. This requirement is intended to cover instances when the following types of contractual arrangements are proposed: (1) changes in, amendments to or new firm pipeline supply contracts; (2) changes in, amendments to or new firm gas storage contracts and for firm transportation of storage gas; (3) firm supplies of gas from a producer under a contract covering a two-year period or longer, along with related transportation arrangements; (4) any arrangement for supplemental resources for which the supply is intended for use for a period longer than a single heating season, except for arrangements in which the company can adjust the LNG volumes for the following heating season, or for arrangements concerning supplies intended primarily for system operation.

The Siting Council expects companies to prepare such analyses as part of their routine planning efforts when considering major new supply options. However, the Siting Council does not prescribe a particular methodology that companies must use in these cost studies. Also, if Fitchburg is already performing such studies, the Siting Council does not require the Company to conduct additional studies to meet this requirement. Finally, the Siting Council does not require the submission of such studies as part of each forecast or forecast-supplement filing; however, Fitchburg may be required to make individual studies available to the Siting Council at its request in cases where the Siting Council or its Staff believes the results of such studies are needed to develope a complete review of the Company's supply plan.

VIII. ORDER

The Siting Council APPROVES the Fourth Supplement to the Second Long-Range Forecast of gas requirements and resources of Fitchburg Gas and Electric Light Company subject to the following CONDITIONS which are to be met in the Third Long-Range Forecast to be filed on October 1, 1986:

1) That the Company shall include in its next Supplement the results of its marginal cost study and a discussion of the status of development of conservation and load management programs. The discussion shall include a comparison of the cost-effectiveness of relying upon conserved gas as a source of supply versus obtaining other gas supplies to meet new load requirements, and a justification of the method of comparison.

2) That the Company shall provide, in its next Supplement, sufficient documentation to support the assumptions in its methodology of deriving customer use factors that these factors will remain constant during the five-year forecast period and that this methodology allows the Company to adjust its projections for known changes in sendout requirements for all classes. Fitchburg shall also provide the supporting documentation justifying its assumption that heating use per degree day does not increase during extremely cold days.

3) That the Company shall provide in its next filing a narrative description of why or why not the effects of conservation were included, and, if conservation is included, how it is included.

4) That the Company shall include in its next filing a contingency plan for LNG, including: the status of the Distrigas and DOMAC federal government applications; the impact of Order No. 380 on DOMAC's ability to supply Bay State with LNG and the resultant capability of Bay State to supply Fitchburg with LNG; and identification of other potential suppliers of LNG, and possible terms of delivery.

5) That the Company faithfully comply with the Siting Council's Order in Docket No. 85-64 and that Order's implementation in Administrative Bulletin 86-1.

Susan F. Tierney
Hearing Officer

Dated at Boston, Massachusetts this 7th day of August, 1986.

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of August 7, 1986, by the members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs and Business Regulation); Stephen Roop (for Secretary James S. Hoyte, Secretary of Environmental Affairs); Joellen D'Esti (for Secretary Joseph D. Alviani, Secretary of Economic Affairs); Joseph Joyce (Public Member, Labor); Dennis LaCroix (Public Member, Gas); and Madeline Varitimos (Public Member, Environment). Ineligible to vote: Elliot Roseman (Public Member, Oil); Stephen Umans (Public Member, Electricity). Absent: Patricia Deese (Public Member, Engineering).

August 14, 1986
Date

Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the)
City of Westfield Gas and Electric)
Light Department for Approval of the)
1985 Supplement to the Second Long-)
Range Forecast of Gas Requirements)
and Resources)

Docket No. 85-26

FINAL DECISION

Susan F. Tierney
Hearing Officer

Calvin Young
Analyst

August 18, 1986

TABLE OF CONTENTS

I. Introduction

The Energy Facilities Siting Council ("Siting Council") APPROVES the 1985 Supplement to the Second Long-Range Forecast of Gas Requirements and Resources ("Supplement") of the City of Westfield Gas and Electric Light Department ("Westfield" or "Department"), subject to the Conditons imposed herein.[1]

A. History of Proceedings

Westfield filed the current Supplement on November 13, 1985. A Notice of Adjudication of the 1985 Supplement was issued and duly published in accordance with the Hearing Officer's instructions. As no petitions to intervene or motions to participate as an interested person were filed by the deadline specified in the Notice of Adjudication, this proceeding was left in an uncontested posture.

While consideration of the 1985 Supplement was pending, the Staff issued a Notice of Inquiry into an Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Massachusetts Natural Gas Utilities ("the Notice of Inquiry") in Siting Council Docket No. 85-64. The purpose of the Notice of Inquiry was to solicit comments from all Massachusetts natural gas companies subject to the Siting Council's jurisdiction as to how the Siting Council's review process for gas company forecasts and supply plans could be made more efficient and effective, and its decisions on those forecasts and supply plans more meaningful.

The Notice of Inquiry set forth a large number of specific suggestions for changes in the standards and procedures followed by the Siting Council in gas company forecast and supply plan proceedings. After requesting and receiving written comments on these suggestions from all of the regulated gas companies, the Staff held 10 days of hearing on the Notice of Inquiry in November of 1985. Westfield appeared at the hearings on November 15, 1985, and answered numerous questions from the Staff regarding not only the issues raised in the Notice of Inquiry but also the contents of the 1985 Supplement itself. While Westfield's witnesses did not testify under oath, they cast considerable light on certain aspects of the 1985 Supplement. The transcript of that hearing are referred to in this Decision as ("Tr., 11/15/85 at __"), and will be made a part of the record of this proceeding.

As stated in the Procedural Order of October 22, 1985 in Docket No. 85-64, the present Decision is made on the basis of the Siting Council standards and procedures which prevailed at the time the 1985 Supplement was filed. However, certain applicable changes to those standards and procedures resulting from the Notice of Inquiry and the resultant Order in Docket No. 85-64 are discussed <u>infra</u>, along with suggestions and instructions for their implementation in the 1986 filing.

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1. The Siting Council approved the Second Annual Supplement to the Second Long Range Forecast in May, 1985. <u>In Re: City of Westfield Gas and Electric Light Dept.</u>, 12 DOMSC 243 (1985).

B. Record

This Decision is made on a record consisting of: the 1985 Supplement; the transcript of the Notice of Inquiry in Siting Council Docket No. 85-64; and a letter from Mr. Daniel Golubek, Gas Superintendent of the City of Westfield Gas and Electric Light Department, to Mr. Calvin Young, Staff Analyst, dated July 14, 1986.

C. Background

Westfield is a municipal utility and is the tenth largest distributor of natural gas in the Commonwealth in terms of annual gas sendout.[2] Table 1 reflects Westfield's total annual for sendout and the average number of customers for split year 1984/85 by class.

Table 1 - Total Annual Firm Sendout and Average Number of Customers 1984/85

	Annual Sendout (MMcf)	Average Customers
Residential Heat	439.8	4,192
Residential Non-heat	54.0	1,559
Commercial	386.6	582
Industrial	50.3	18
Municipal	16.9	22
Company & Unacc't	71.2	-
Total Firm	1,018.8	6,373

Of the 6,373 average customers, 90 percent were residential customers and of the approximately 1,000 MMcf of firm sendout, 83 percent was consumed by residential heat and commercial customers.

D. Prior Conditions

In its last decision involving Westfield, the Siting Council imposed eight conditions.

1. That Westfield review its current source of weather data for consistency with historic data in Westfield and with data used by utilities serving neighboring communities. Westfield should justify the source of weather data it uses for the 1985 Supplement in the accompanying narrative.

2. That Westfield research, evaluate and report the findings on alternatives to its current design and normal year sendout forecast methodology, which is based on the most recent year's sendout data.

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2. G. Aronson, Report of the Energy Facilities Siting Council, "The Gas Industry in Massachusetts" (March, 1983).

3. That Westfield, in its next filing, include its planned Daily Dispatch Log for 1985/86. The 1985 Supplement's sendout forecast should be consistent with the planned Daily Dispatch Log for 1985/86, and any remaining differences between the forecast and the Daily Dispatch Log should be explained and justified in the narrative accompanying the 1985 Supplement.

4. That Westfield research design year criteria and select an acceptable design year criteria, such as was used in Westfield's 1981 Forecast.

5. That Westfield file sendout data on interruptible sales on form G-4(A) instead of form G-4(B), and correctly file the G-22 forms.

6. That Westfield explain and document its knowledge of the community and use of judgement in adjusting average number of customers and load factors.

7. That Westfield provide a cost study determining the level at which its MDQ for Tennessee should be set and the quantity of Bay State gas supplies it will need beginning in 1988-89.

8. That Westfield meet with the Siting Council's staff before July 1, 1985 to discuss compliance with these conditions.[3]

II. Scope and Standard of Review

The Commonwealth of Massachusetts mandates that the Siting Council review sendout forecasts of each gas utility to ensure the accurate projection of gas sendout requirements of a utility's market area. Siting Council Rules 62.9(2) (a), (b) and (c), require the use of accurate and complete historical data and a reasonable statistical projection method. In its review of a forecast, the Siting Council determines whether a projection method is reasonable according to whether the methodology is: (a) appropriate, or technically suitable for the size and nature of the particular gas utility's system; (b) reviewable, or presented in a way such that the results can be evaluated and duplicated by another person given the same information and resources; and (c) reliable, that is, provides a measure of confidence that the gas utility's assumptions, judgements and data will forecast what is most likely to occur. The Siting Council applies these criteria on a case-by-case basis.

In order to ensure that the required gas is supplied to a utility's customers with a minimum impact on the environment at lowest cost, the Siting Council focuses its supply review on the adequacy, cost and reliability of gas supplies needed to meet projected sendout requirements. The adequacy of supply is measured by the company's ability to meet projected peak day, cold-snap, and total annual firm sendout requirements with sufficient reserves under both normal and

3. In Re: City of Westfield Gas and Electric Light Dept., 12 DOMSC 243, 265-66 (1985).

design weather conditions. The review of cost of supply addresses cost minimization in concert with notions of adequacy and reliability of natural gas supply. The reliability of supply reviews the likelihood that the resources will be available to meet or contribute to meeting firm sendout requirements under normal year, design year, peak day, and cold-snap conditions.

III. Analysis of Sendout Requirement

A. Overview of Forecast Methodology

Westfield has developed its forecast using basically the same methodology as employed in its previous filings.

This forecast uses a methodology developed by the American Gas Association for small gas distribution companies.[4] Westfield generates normal and design year forecasts by customer class. For each class, the following formulas are used to project normal year and design year sendout, respectively:

(1) [(class average number of customers) x (class base load factor) x 365] + [(class average number of customers) x (class heating factor) x (normal year degree days)]

and

(2) [(class average number of customers) x (class base load factor) x 365] + [(class average number of customers) x (class heating factor) x (design year degree days)].

Previously, Westfield had constructed its base load and heating load factors for each class of customers from its most recent split-year. However, in this filing, the Department calculates its base load and heating load factors by adjusting the 1984/85 factors by the average yearly growth rate for the residential heating, residential non-heating, and commercial customer classes.[5] The base load is derived from sales data for the months of June, July and August. In each year, base load factors are adjusted for conservation. A heating load factor for each class is calculated by subtracting base load from total sendout and dividing the remainder by the average number of customers and by the number of degree days. Heating load factors are adjusted judgementally for conservation, and improvements in appliances and machinery. Projections of heating load by class are compiled by multiplying projected average number of customers times the adjusted heating load factors and normalized (or design) degree days. Base load is added to heating load to obtain total class sendout.

Individual customer class projections are summed and added to company use and unaccounted-for sendout projections to derive total firm sendout. Projected average number of customers are determined from historical data and an intimate knowledge of the community.

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4. See American Gas Association, A Simplified Approach to Forecast Gas Sales and Revenues: For the Small Gas Distribution Company, 1983.

5. The average rate of growth is based upon five years of data.

The Department forecasts the number of customers by calculating the average growth rate in customers for the previous five years, then projecting that the actual number of customers will increase by the average for each year of the forecast period.

The Siting Council finds Westfield's methodology to be sound and appropriate for a gas utility of its size and resources.[6] Further, Westfield's incorporation of backup work papers into the filing was essential to the reviewability of the 1985 Supplement.

B. Impact of Weather and Conservation

1. Source of Degree Day Data

In the last filing, it was found that Westfield's temperature recording instrument was incorrectly recording weather data.[7] As a result, Condition 1 of the preceding decision required that the Department review its current source of data.

The Department compared its degree days data with that of the City of Holyoke Gas and Electric Light Department and that of Berkshire Gas Company. An average of the degree days of the three local distribution companies was constructed and Westfield found that it was closer to the average than either Holyoke or Berkshire. Westfield justifies the continued use of its temperature recording instrument on this basis.[8]

The Siting Council does not find this to be a convincing justification for Westfield's continued reliance on its current weather recording instrument. In particular, it is not necessarily important that Westfield's monthly degree days are closer to the mean of the three gas utilities' monthly degree days because the Department has not demonstrated that its degree days should be closer to the mean than those of either Berkshire or Holyoke.

However, the Siting Council does find other compelling justifications: all three gas utilities' degree day data indicate that 1984/85 split-year was warmer than normal for each utility; Westfield has installed two other back-up temperature recording systems; and Westfield is exploring purchasing its weather data from an outside vendor.[9]

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6. The appropriateness of a methodology for a gas utility depends upon the size of the market and the resources available to the Department. See In Re: N. Attleboro Gas Co., 10 DOMSC 159, 160 (1984), for standards set for a utility of similar size and resources to Westfield.

7. See In Re: City of Westfield Gas and Electric Light Dept., 12 DOMSC 243, 248 (1985) at footnote 11. Also, a discussion of the impact of faulty weather data upon the sendout forecast in the preceding decision is provided at 248 and 249.

8. See 1985 Supplement and Tr. 11/15/86, at 90-91.

9. Tr. 11/15/86, at 91.

Thus, the Siting Council finds continued use of the temperature recording instrument to be appropriate.

Nevertheless, the Siting Council cautions Westfield that it should continue to monitor its weather recording instruments and to explore the possibility of purchasing its weather data.

Westfield uses a 65° Fahrenheit standard as the temperature above which heating load is zero. Westfield employs this standard to derive degree days as a measure of coldness in determining normal and design year planning criteria, and to forecast heating load increments.[10] Degree day data for Westfield are provided in Table 2. The reported degree days indicate that 1984/85 was a warmer than normal split-year.

Table 2 Degree Day Data

Split Year 4/1-3/31	Non-Heat Season	Heat Season	Total Split Year
1980/81	1207	5129	6336
1981/82	1382	5256	6638
1982/83	1450	4530	5980
1983/84	1652	5377	7029
1984/85	1478	4891	6369
Normal	1393	5039	6432
Design	1609	5118	6727

2. Design Year Criteria

In its last Decision, the Siting Council found unacceptable Westfield's design year standard of a coldest heating season plus coldest non-heating season. Condition 4 of the preceding Decision required Westfield to re-evaluate its design year standard. In the current filing Westfield has chosen the coldest split-year in the last eighteen years as its design year criterion. The Siting Council finds the coldest split-year in eighteen years to be an appropriate design year standard.

Westfield indicated that it preferred a design year criteria which was based upon a percentage deviation from the degree days for a normal year to a design year criteria based upon recurrent probability, that is, the coldest year within a specific time period.[11] The Siting Council encourages the Department to continue to explore the possibility of using a percentage deviation from a normal year's degree days as its design year criteria.

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10. The number of degree days in a day is calculated by subtracting the average temperature for the day from 65° F. Average temperature is the day's high temperature plus the day's low temperature divided by two.

11. See Tr. 11/15/86 at 62.

3. Peak Day Standard

The peak day standard is 69 degree days and represents the coldest day in eighteen years. The 1985 Supplement forecasts peak day sendout as 7.7 MMcf in 1985/86, 7.6 MMcf in 1986/87, 7.6 MMcf in 1987/88, 7.7 MMcf in 1988/89, and 7.7 MMcf in 1989/90.

Yet, the actual peak degree day for 1984/85 was 56 with 7.8 MMcf of sendout. In 1984/85, a normalized heating sendout projected a base load per day of 1.163 MMcf and a heating factor per degree day of 0.08514 MMcf. On its face, then, it appears that Westfield is underestimating its peak-day sendout requirements.

To investigate this question, the Siting Council Staff analyzed information provided by Westfield in its Daily Dispatch Log, which the Department had submitted in response to Condition 3 of the preceding decision. The Department also provided its actual Daily Dispatch Log for 1984/85. This data were grouped by the Siting Council Staff to examine whether the sendout was linearly related to degree days.

The month of January had 21 days for which the degree days were 40 or more. The Siting Council constructed actual heating factors per degree day for each of these days and the value for heating factors per degree day ranged from 0.09986 MMcf per degree day to 0.12490 MMcf with a mean of 0.10913 MMcf per degree day. This exceeds 0.08514 by about 0.024 MMcf, or by 28 percent. For a heating factor per degreeday of 0.10913 MMcf, 69 degree days would yield a design peak day sendout of 8.693 MMcf instead of 7.680 MMcf in 1985/86.

In addition, February had 9 days of 40 or more degree days for which the constructed heating factors per dgree day range from 0.09044 MMcf to 0.11693 MMcf with an average heating factor per degree day of 0.10554 MMcf. Furthermore, December had 4 days of 40 or more degree days with heating factors per degree day ranging from 0.09468 MMcf to 0.11318 MMcf.

It appears, then, that heating factors per degree day increase with degree days. If so, Westfield's, then peak-day sendout requirements might be underestimated. The Siting Council therefore requires that Westfield reexamine its data and re-evaluate the reliability and validity of its peak-day projection methodology.

4. Two Week Cold-Snap Requirements

Westfield's cold-snap criterion is the coldest two-week period in the last eighteen years. The degree days range from 25 to 69. Again, the Siting Council believes that Westfield's projection of sendout for cold-snap requirements is underestimated because heating factor per degree day is an increasing function of degree days.

5. Conservation

Westfield's conservation program is not extensive.[12]

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12. See In Re: City of Westfield Gas and Electric Light Dept., 12 DOMSC 243, 250-51 (1985) for a brief discussion of the Department's conservation programs.

Previously, Westfield judgementally decreased its load factors for all of its customer classes for conservation.[13] In its last decision involving Westfield, the Siting Council noted that the base and heating use factors for the Department's customer classes did not exhibit a consistent pattern of decline.[14] The Department has discontinued its practice of judgementally decreasing its use factors for conservation in this filing. The Siting Council urges the Department to continue to evaluate its sendout data to determine if there are any trends associated with the impact of conservation.

C. Forecast of Total Firm Sendout

1. Normal Year

As indicated in Table 3, the Department projects that both heating and non-heating season sendout sendout requirements for a normal year will increase during the forecast period. Total sendout for a normal year will increase from 1,095.0 MMcf in 1985/86 to 1,168.6 MMcf in 1989/90. This represents a modest growth rate in normal year firm sendout requirements of 1.6 percent per annum.

2. Design Year

As also indicated in Table 3, the Department similarly projects that sendout requirements will increase for design year conditions. For a design year occurring during the forecast period, total sendout will increase from 1,121.9 MMcf in 1985/86 to 1,189.2 MMcf in 1989/90. This represents a modest growth rate in design year firm sendout requirements of 1.5 percent per annum.

Table 3
Total Firm Company Sendout
(Including Company Use and Losses)

	FORECAST SENDOUT (MMcf)			
	NORMAL		DESIGN	
SPLIT-YR SEASON	NON-HEATING SEASON	HEATING SEASON	NON-HEATING SEASON	HEATING SEASON
1985-86	430.2	664.9	449.3	672.6
1986-87	439.7	667.6	457.6	672.9
1987-88	452.6	674.4	469.9	679.0
1988-89	464.3	670.6	481.9	685.6
1989-90	479.6	689.0	496.1	693.1

13. Ibid. at 251.

14. Ibid. at 252-56.

D. Forecast of Sendout by Customer Class

In its previous decision, the Siting Council recognized that the reliance on the Department's "judgement and intimate knowledge of community affairs is indispensable in developing reliable forecasts for companies of Westfield's size and resource."[15] However, the only evidence of judgemental adjustment of use factors or the number of customers was the adjustment of use factors for conservation. The Siting Council noted that "past forecasts said to be based on such judgement and knowledge have proven possibly inaccurate."[16] The Siting Council was concerned about the mechanistic adjustment for conservation while other factors affecting sendout such as gas price, oil price, income and commercial activity were ignored. Accordingly, the Siting Council, in Condition 6, ordered the Department to explain and document its knowledge and use of judgement in adjusting its projection of the number of customers and use factors. The Department did not comply with this condition.[17] In fact, at the Notice of Inquiry gas hearing, the Department expressed the concern that if it incorporated into the forecast information that was out of the ordinary, then the Department would can expect voluminous discovery questions from the Siting Council Staff.[18]

In addition, Condition 2 of the preceding decision required Westfield to research, evaluate and report the findings on alternatives to its design and normal year sendout methodology of basing its load factors upon one year's data. The Siting Council expressed a concern that basing use factors upon only one year's data tended to lead to significant fluctuations in sendout requirements from year to year. The Department response to Condition 2 is discussed infra. under each customer class.

1. Residential Heating

Westfield expects the number of residential heating customers to increase by 18.6 customers per year, increasing from 4211 in 1985/86 to 4286 in 1989/90. The Siting Council notes that if the Department had used only four years of data instead of five, then Westfield would have forecasted little or no change in its number of customers.[19]

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15. Ibid. at 257 and In Re: City of Westfield Gas and Electric Light Dept., 11 DOMSC 149, 152 (1984).

16. In Re: City of Westfield Gas and Electric Light Dept., 12 DOMSC 243, 258 (1985).

17. Due to the impending gas hearing, the Staff and representatives of Westfield did not meet to discuss compliance with the conditions of the preceding decision.

18. Tr. 11/15/86, at 44, 45.

19. The actual numbers of residential heating customers were 4091 in 1980/81, 4193 in 1981/82, 4192 in 1982/83, 4197 in 1983/84, and 4192 in 1984/85.

In spite of the projected increase in customers for the forecast period, sendout for the residential heating customer class is projected to decline during the forecast period. Residential heating customer sales is expected to decline from 432.8 MMcf in 1985/86 to 398.8 MMcf in 1989/90.

Base and heating use factors were calculated by trending the actual base and heating use factors by the average growth rate for the 1980/81 to 1984/85 period.[20] During this period, the base use factor increased, but the heating use factor decreased. The decline in heating use factors was sufficient to cause the forecasted decline in residential heating customer sales. Base use per customer is projected to increase by 0.00028 Mcf per year and heating is projected to decrease by 0.00044 Mcf per year.

2. Residential General

Westfield expects the number of residential heating customers to decrease by 14 customers per year, decreasing from 1545 in 1985/86 to 1489 in 1989/90.

Residential general customer sales is expected to decline from 55.5 MMcf in 1985/86 to 53.5 MMcf in 1989/90. In response to Condition 2 of the preceding filing, the base and heating use factors employed to forecast sendout requirements for this customer class were calculated as the average base and heating use factors for the five-year period of 1980/81 to 1984/85.

3. Commercial

Westfield expects the number of commercial customers to increase by about two customers per year.[21] Increasing from 602 in 1985/86 to 612 in 1989/90.

Commercial customer sales is expected to increase from 420.6 MMcf in 1985/86 to 519.0 MMcf in 1989/90. Base and heating use factors were calculated by trending the actual base and heating use factors by the average growth rate for the 1980/81 to 1984/85 period. During this period, the base and heating use factors increased.

4. Industrial

In 1982/83, Westfield lost five industrial customers. Previously, the Department had stated it expected those customers to return to gas

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20. In the previous filing, the Department base and heating use factors were obtained by adjusting the previous year's calculated base and heating use factors for conservation. <u>In Re: City of Westfield Gas and Electric Light Dept.</u>, 12 DOMSC 243, 247 (1985).

21. <u>In Re: City of Westfield Gas and Electric Light Dept.</u>, 12 DOMSC 243, 247 (1985).

heating.[22] Westfields expect to gain one customer every other year. Thus, the number of industrial customers is expected to increase from 19 customers in 1985/86 to 21 in 1989/90. In its next filing, Westfield should report on the impact of declining oil prices on the number of industrial customers.

Industrial customer sales is expected to rise from 93.3 MMcf in 1985/86 to 103.2 MMcf in 1989/90. In response to Condition 2 of the preceding filing, the base and heating use factors employed to forecast sendout requirements for this customer class were calculated as the average base and heating use factors for the five-year period of 1980/81 to 1984/85.

5. Municipal

Westfield expects to gain one municipal customer per year. Thus, the number of industrial customers is expected to increase from 23 customers in 1985/86 to 26 in 1989/90. The load growth of municipal customers is dependent upon the Westfield School System converting to a dual-fuel system, which is dependent upon budget constraints.[23] Again, Westfield should in its next filing report on the impact of declining oil prices on the willingness of the school system to install dual-fuel heating systems.

Municipal customer sales are expected to decline from 16.1 MMcf in 1985/86 to 13.3 MMcf in 1989/90. Base and heating use factors were calculated by trending the actual base and heating use factors by the average growth rate for the 1980/81 to 1984/85 period.

6. Company Use & Unaccounted For

Westfield calculates its company use and unaccounted for sendout as 5.84 percent of total sales. The Department expects its company use and unaccounted for sendout to increase from 60.4 MMcf in 1985/86 to 64.5 MMcf in 1989/90.

7. Resale and Interruptible Sendout

In the past, Westfield has sold excess pipeline gas to Bay State Gas Company ("Bay State"). Westfield last sold excess pipeline gas supplies in 1982. Westfield does not anticipate that there will be future sales to Bay State.

Westfield has one interruptible customer which does not receive gas on peak days and receives gas during the heating seaseon only to the extent possible. Westfield forecasts interruptible sales to remain constant at 16.24 MMcf throughout the forecast period.

Condition 5 of the preceding decision required Westfield to file interruptible sales data on form G-4(A); the Department complied with this requirement.

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22. Ibid. at 256.

23. 1985 Supplement narrative (unnumbered) Tr. 11/15/86, at 71-72.

E. Summary and Conclusions

The Siting Council commends Westfield for its new format for presenting data which made the 1985 Supplement extremely reviewable. The Siting Council observes that Westfield has computerized its forecast and its use of the computer has enhanced the filing and expedited its review.

The Siting Council finds Westfield's methodology to be sound and appropriate relative to the size and resources of the Department. Further, Westfield's submission of backup work papers was essential and improved the reviewability of the filing.

However, the Siting Council notes that the Department's methodology for forecasting sendout is only as reliable as the underlying data and the intimate knowledge of community activity used in making judgemental adjustments to the data. Westfield should demonstrate how its uses its judgement to adjust its use factors.

Further, the Siting Council observes that the Department indicated that it produces two forecasts--one prepared for the Siting Council, and one prepared for internal supply planning purposes.[24] The internal forecast is more accurate than that prepared for the Siting Council. Because the Siting Council wants to review the Department's planning process, the Siting Council finds that Westfield should incorporate in the next forecast prepared Siting Council the subjective assumptions and judgemental adjustments used in the internal forecast and supply plan. Condition Two addresses this issue. In order to meet the concerns of the Department about the discovery processs, the Siting Council commits itself to a discovery process appropriate to a gas utility of Westfield's size and resources. The Staff is prepared to meet with the Department to discuss the implementation of the recommendations and conditions of this decision.

24. Tr. 11/15/86 at 47, 96-99.

IV. Resources and Facilities

Westfield relies on pipeline gas purchased from Tennessee Gas Pipeline Company ("Tennessee") to meet most of its sendout requirements. During cold weather, Westfield also sends out LNG and propane-air.

Westfield purchases pipeline gas under Tennessee's G-6 Rate Schedule pursuant to a contract dated October 9, 1981.[25] The initial termination date of the contract is November 1, 2000 with automatic annual extensions unless cancelled on twelve months' written notice of either party. The maximum daily quantity ("MDQ") is 5.079 MMcf. The annual volumetric limitation ("AVL") is 1,854 MMcf, representing the MDQ times the number of days in each year.

Tennessee has filed with the Federal Energy Regulatory Commission ("FERC") in Docket No. 86-441 for a Certificate of Public Convenience and Necessity so that Tennessee can expand its services to several Massachusetts gas utilities including Westfield.[26] Westfield has requested from Tennessee that its MDQ be raised to 6.25 MMcf. The new contract would permit Westfield to raise its MDQ beyond 6.25 MMcf provided Tennessee is given two years' notice. In its next filing with the Siting Council, the Department should discuss the status of the Tennessee expansion project and respond to Condition Four, which addresses the issue of the impact of the expansion project upon Westfield.

Westfield purchases LNG from Bay State pursuant to a contract dated October 25, 1978, as amended on August 23, 1982. As amended, the contract provides for 73 MMcf of firm volumes and 23 MMcf of optional volumes. The contract has an initial expiration date of March 31, 1988, but will continue in effect on a year-to-year basis thereafter unless cancelled on twelve months' written notice of either party. The Department has not decided whether it will cancel its contract with Bay State.[27]

Westfield purchases the firm quantities of LNG on a take-or-pay basis. Westfield exercises the option to purchase additional volumes on ten days' notice prior to the month in which the gas is to be made available. The elected optional quantities become the take-or-pay responsibility of Westfield.

Under the Bay State contract, Westfield is obliged to use its best efforts to receive the gas by displacement (pursuant to one hour advance notice) through an interconnection between the two companies on Westfield Street in North Agawam. The contractual maximum hourly rate of delivery by displacement is 50 Mcf. If the gas cannot be delivered by displacement, delivery is accomplished by LNG (or propane at Westfield's option) through truck transportation provided by Bay State. Westfield requests truck

25. Previously, the Department was able to purchase spot market pipeline gas under Tennessee's rate R-6 gas. See In Re: City of Westfield Gas and Electric Light Dept., 12 DOMSC 243, 259 (1985).

26. See In Re: City of Westfield Gas and Electric Light Dept., 12 DOMSC 243, 261 (1985) and Tr. 11/15/86 at 66-70, and 73-74.

27. Tr. 11/15/86 at 55.

deliveries on twenty-four hours' advance notice, but is constrained to request delivery in full truckloads.

Westfield's LNG facility has a design maximum daily sendout of 12 MMcf. During the 1982/83 split-year, the total LNG sendout from storage was 16.3 MMcf, and the maximum daily sendout was 2.02 MMcf.

Westfield's propane facility has a storage capacity of 8.49 MMcf and a design maximum daily sendout of 1.2 MMcf. For the past three split-years, however, Westfield had no propane sendout. Westfield's current filing indicates no propane supply contracts through the forecast period.

V. Cost Study

In Condition 7 of the preceding decision, the Siting Council ordered Westfield to provide a cost study which would compare the costs of various options for AVL and MDQ for Tennessee's G-6 gas with appropriate levels of supplementals. In compliance with this condition, Westfield submitted in July of 1986 a cost study comparing the incremental cost of ten options involving various levels of Tennessee gas to a base case. The base case is the actual cost of supplemental fuels for split-year 1985/86.[28]

A. Methodological Issues

The Siting Council had problems reviewing Westfield's cost study due to poor documentation. Specifically, the Department failed to provide documentation on the degree days for 1985/86, demand and commodity charges for Tennessee rate G-6 gas for each MDQ levels, and a load duration curve. Also, the cost study did not include a narrative.

In its cost study, Westfield evaluated the cost various levels of Tennessee gas, which included:

(a) The MDQ of Tennessee rate G-6 gas set at 6.25 MMcf with supplemental production set at 51 MMcf;
(b) The MDQ of Tennessee rate G-6 gas set at 6.5 MMcf with supplemental production set at 40 MMcf;
(c) The MDQ of Tennessee rate G-6 gas set at 6.75 MMcf with supplemental production set at 31 MMcf;
(d) The MDQ of Tennessee rate G-6 gas set at 7.0 MMcf with supplemental production set at 24 MMcf;
(e) The MDQ of Tennessee rate G-6 gas set at 7.25 MMcf with supplemental production set at 19 MMcf;
(f) The MDQ of Tennessee rate G-6 gas set at 7.5 MMcf with supplemental production set at 15 MMcf;
(g) The MDQ of Tennessee rate G-6 gas set at 7.75 MMcf with supplemental production set at 11 MMcf;

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28. The cost study consisted of a computer printout provided in a letter from Mr. Daniel Golubek, Gas Superintendent of the City of Westfield Gas and Electric Light Department, to Mr. Calvin Young, Staff Analyst, dated July 14, 1986.

(h) The MDQ of Tennessee rate G-6 gas set at 8.0 MMcf with supplemental production set at 8 MMcf;
(i) The MDQ of Tennessee rate G-6 gas set at 8.25 Mcf with supplemental production set at 6 MMcf;
(j) The MDQ of Tennessee rate G-6 gas set at 8.5 Mcf with supplemental production set at 4 MMcf.

In the cost study, the Department compared the incremental cost of each of the options with respect to a base case. The base case is the actual cost of Westfield's supplemental fuels for the 1985/86 split-year. Each option involves increasing Westfield's MDQ of pipeline gas through Tennessee's expansion project in order to displace supplemental fuel in split-year 1985/86 assuming the option could be available that year. Thus, Westfield compared what the incremental cost would have been in 1985/86 for each option with the actual supplemental cost. The difference between supplemental fuel cost and the incremental fuel cost for an option represents the net savings that the rate payers would have had in 1985/86.

The incremental cost of each option is equal to the increased demand and commodity charges associated with the increase in MDQ plus cost of peak shaving fuels. Supplemental fuels are required only when daily sendout exceeds the MDQ for Tennessee's pipeline gas.

Westfield is commended for performing such a study and making it available to the Siting Council. The Siting Council has indicated in its Notice of Inquiry that it will scrutinize cost more closely in its evaluation of gas supply plans than it has in the past. The Siting Council finds the range of supply plan options considered in the study to be appropriate for a gas utility of Westfield's size and resources.

However, the Siting Council also finds the cost study not to be reliable because of two methodological flaws. First, Westfield used actual sendout requirements for 1985/86, when it should have used normalized sendout requirements. Second, the Department did not consider any alternative scenarios in which the various options are evaluated.

The use of actual 1985/86 would underestimate or overestimate net savings associated with all options depending upon whether split-year 1985/86 was warmer or colder than normal. The bias might increase as the MDQ level increases. If 1985/86 were a warmer than normal year, then the amount of supplemental fuel needed to meet sendout requirements would be less than that needed for a normal year's weather and the study would underestimate the net savings associated with each option. If 1985/86 were a colder than normal year, then the amount of supplemental fuels needed to meet sendout requirements would be more than that needed for a normal year and the study would overestimate the net savings associated with each option. Also, since sendout requirements are expected to increase during the forecast period, less supplemental fuels are available to be displaced by increasing MDQ levels in 1985/86 than would be the case during the forecast period.

In addition, the Department should have examined an alternate scenario involving a design year's weather in its cost study. Options with higher MDQs might have larger net savings than that given in the cost study because more supplemental fuel would be displaced.

B. Results

The results of the study are presented in Table 4. The most cost effective option, option A, would increase the MDQ for Tennessee rate G-6 gas to 6.25 Mcf. Option A represents the Department's preferred supply plan. This is the MDQ level the Department has requested from Tennessee.[29]

On the basis of the Department's own cost study, its preferred supply plan is the least cost supply plan. However, the cost study has flaws which may have biased the results of the study. Since the study was based upon the actual sendout data for 1985/86, the results might have underestimated or overestimated the net savings for all options as discussed supra, at 17. In addition, the study should have examined design year conditions in which options possessing higher MDQs would have had larger net savings than the cost study indicates.

VI. Comparison of Resources and Requirements

A. Normal Year

Tables 5 and 6 portray Westfield's plan for meeting sendout requirements in a normal season. Requirements are met with purchases of Tennessee pipeline gas, Bay State firm supplies and stored LNG. Propane gas and Bay State optional supplies are not used. Westfield sends out all of its Bay State firm quantities, but less than the available Tennessee G-6 is used. Of the 1,854 MMcf pipeline gas available, Westfield intends to dispatch 990 MMcf in 1985/86 and 1,058 MMcf in 1989/90. Bay State quantities and stored LNG are used for peak shaving. Westfield has sufficient resources available to meet requirements of its firm customers without significant disruptions of interruptible service.

The Siting Council is concerned about Westfield's reliance upon Bay State's LNG to meet its sendout requirements. Distrigas Corporation has filed for bankruptcy.[30] Distrigas of Massachusetts Corporation, a subsidiary of Distrigas Corporation, supplies Bay State with LNG which enables Bay State to resell LNG to Massachusetts and New Hampshire gas utilities including Westfield. Thus the future availability of this source of LNG supply is uncertain. Due to this uncertainty, the Siting Council in Condition Three of this Decision will order the Department to address this issue in its next filing.

During the heating season, Westfield could meet its firm sendout requirement with Tennessee G-6 gas except for peak shaving. Peak shaving is required when daily sendout exceeds 5.079 MMcf. Last year daily sendout would have been expected to exceed 5.079 at 46 degree days. However, the Siting Council's analysis indicates that sendout requirements might be considerably underestimated at degrees exceeding 40 degree days. Therefore, total sendout is likely to be greater in a normal heating season than Westfield projects in its forecast. Yet, Westfield's resources are more than adequate to meet requirements until 1988/89 when Westfield's Bay State contract expires.

29. Tr. 11/15/86 at 69.

30. In Re: Bay State Gas Co. (EFSC Docket No. 85-13, Order dated June 27, 1986 at 26), in DOMSC ______.

Table 4
Cost Study Results

	MDQ (Mcf)	Supplemental Fuel Use (MMcf)	Supplemental Cost (in $000)	Incremental Pipeline Gas Cost (in $000)	Total Cost (in $000)	Net Savings (in $000)
	5.08	134	899	---	900	---
A.	6.25	51	341	448	789	110
B.	6.50	40	266	524	790	110
C.	6.75	31	206	593	799	101
D.	7.00	24	162	655	817	83
E.	7.25	19	125	713	838	62
F.	7.50	15	99	767	866	34
G.	7.75	11	76	819	895	5
H.	8.00	8	54	871	925	(25)
I.	8.25	6	38	920	957	(58)
J.	8.50	4	28	966	994	(94)

Table 5
Comparison of Resources and Requirements
During a Normal Year's
Non-heating Season
(MMcf)

	85/86	86/87	87/88	88/89	89/90
Requirements					
Firm	414.0	423.5	436.3	448.1	463.4
Interruptible	16.2	16.2	16.2	16.2	16.2
LNG refill	----	----	----	----	----
Total	430.2	439.7	452.5	464.3	479.6
Resources					
Tennessee G-6	430.2	439.7	452.6	464.3	479.6
Bay State	----	----	----	----	----
LNG(Storage)	----	----	----	----	----
Propane	----	----	----	----	----
Total	430.2	439.7	452.6	464.3	479.6

Table 6
Comparison of Resources and Requirements
During a Normal Year's
Heating Season
(MMcf)

	85/86	86/87	87/88	88/89	89/90
Requirements					
Firm	664.8	667.6	674.4	679.6	689.0
Interruptible	***	***	***	***	***
LNG refill	----	----	----	----	----
Total	664.8	667.6	674.4	679.6	689.0
Resources					
Tennessee G-6	558.5	560.8	566.5	570.9	578.7
Bay State	67.0	67.3	68.0	68.5	69.4
LNG(purchase)	19.1	19.2	19.4	19.6	19.8
Propane (spot)	20.2	20.3	20.5	20.7	20.9
Total	664.9	667.6	674.4	679.6	689.0

*** Westfield has negligible interruptible sales during the heating season.

During the non-heating season, Westfield dispatches only Tennessee rate G-6 gas.

B. Design Year

Tables 7 and 8 presents Westfield's plans for meeting sendout requirements in a design year. Requirements are met with Tennessee pipeline gas, Bay State firm supplies, spot market propane and stored LNG. Bay State optional supplies are not used. Westfield sends out all of its Bay State firm quantitites, but less than the available Tennesse G-6 is used. Of the 1,854 MMcf pipeline gas available, Westfield intends to dispatch 1,014 MMcf in 1985/86 and 1,078 MMcf in 1989/90. Even in a design year, Westfield uses less than sixty percent of its available pipeline supply. Bay State quantities, spot market propane and stored LNG are used for peak shaving.

The Siting Council notes that Westfield's intended supply plan for meeting design weather conditions includes spot market propane. The Siting Council is concerned about Westfield's reliance upon propane purchased in spot markets as the reliability of spot market propane has not been demonstrated. In its next filing, the Department should address its expectations concerning the availability and reliability of spot market propane and whether it can meet its design year sendout requirements without spot market propane.

C. Peak Day

In addition to having sufficient gas supplies to meet normal and design year requirements of its customers, a gas utility must have sufficient daily pipeline supplies and facilities to meet peak day requirements of its firm customers.

The maximum total daily quantity available for a peak day sendout is 19.5 MMcf. This compares to Westfield's forecast of peak day sendout of 7.7 MMcf in 1985/86 rising to 7.7 MMcf in 1989/90.

Again, the Department's peak day sendout requirements might be underestimated because of a non-linear relationship between degree days and sendout. Still, Westfield's 19.5 MMcf of gas supplies is in excess of requirements by a considerable amount throughout the forecast period, assuming a stored LNG and propane at maximum capacity. However, the Department's ability to replace LNG will be critical for meeting peak day sendout requirements. Thus, in Condition Three of this Decision, Westfield must describe its contingency plan for replacing stored LNG should Bay State supplies not be available.

D. Two-Week Cold Snap[31]

The Siting Council has defined a "cold snap" as a period of peak or near-peak weather conditions, similar to the two-to-three week period experienced during the 1980/81 heating season. The Department's ability

31. See In Re: City of Westfield Gas and Electric Light Dept., 12 DOMSC 243, 263 (1985) for a discussion of the assumptions used by Westfield in its cold snap analysis.

Table 7
Comparison of Resources and Requirements
During a Design Year's
Non-heating Season
(MMcf)

	85/86	86/87	87/88	88/89	89/90
Requirements					
Firm	432.9	441.4	453.6	465.6	479.9
Interruptible	16.2	16.2	16.2	16.2	16.2
LNG refill	----	----	----	----	----
Total	449.0	457.6	469.9	481.9	496.1
Resources					
Tennessee G-6	449.0	457.6	469.9	481.9	496.1
Bay State	----	----	----	----	----
LNG(Storage)	----	----	----	----	----
Propane	----	----	----	----	----
Total	449.0	457.6	469.9	481.9	496.1

Table 8
Comparison of Resources and Requirements
During a Design Year's
Heating Season
(MMcf)

Requirements					
Firm	672.6	672.9	679.0	685.6	693.1
Interruptible	***	***	***	***	***
LNG refill	----	----	----	----	----
Total	672.6	672.9	679.0	685.6	693.1
Resources					
Tennessee G-6	565.0	565.3	570.3	575.9	582.2
Bay State	67.0	67.3	68.0	68.5	69.4
LNG(purchase)	19.2	19.4	19.6	19.7	20.0
Propane (spot)	20.4	20.5	20.6	20.8	21.1
Total	672.6	672.9	679.0	685.6	693.1

*** Westfield has negligible interruptible sales during the heating season.

Table 9
Westfield's Two Week Cold Snap Analysis
(Mcf)

Split Year 1987/88

Fore-casted Degree Days	Total Sendout Required	Tennessee MDQ	Peak Shaving Require	Bay State Interconnect	Production Requirements
69	7649	5079	2570	1200	1370
46	6129	5079	1050	1050	0
42	4948	4948	0	0	0
35	4645	4645	0	0	0
25	3931	3931	0	0	0
43	5287	5079	208	208	0
47	5607	5079	528	528	0
42	5324	5079	206	206	0
48	5957	5079	878	878	0
56	7168	5079	2089	1200	889
63	7990	5079	2911	1200	1711
47	6638	5079	1559	1200	359
36	5378	5079	299	299	0
44	5713	5079	634	634	0

to meet the requirements of its customers during a cold snap depends on its daily pipeline entitlements, its daily supplemental sendout capacity and its storage inventories.

Table 9 presents Westfield's cold-snap analysis for 1987/88.[32] The Department is in a comfortable position with regard to its ability to meet sustained periods of extreme sendout requirements for the first three years of the forecast period. Only for degree days exceeding 46 degree days would Westfield be required to produce peak-shaving other than Bay State LNG through interconnection for 1985/86 through 1987/88. Westfield's peak shaving resources beyond the LNG obtained through its interconnection with Bays State will be met with LNG and propane from storage. According to the cold snap analysis, Westfield would require a total of 4.3 MMcf of peak shaving production. Westfield's propane and LNG facilities' capacity of 13.2 MMcf is more than sufficient to meet sendout requirements for a cold snap until 1988/89.

Should Bay State LNG not be available Westfield would have difficulty meeting its cold-snap requirements. Therefore, the Siting Council in Condition Three of this Decision Orders the Department to submit a contingency plan for meeting requirements should Bay State LNG not be available.

In addition, if heating use per degree day is an increasing function of degree days then sendout requirements are likely to be underestimated for a cold snap period. Again, if Bay State LNG is available, then the suspected underestimation of sendout requirements poses no problems for Westfield as its gas supplies are ample. However, should Bay State LNG not be available then the Siting Council is concerned about the ability of the Department to meet a cold snap, as the suspected underestimation might require more production than Westfield is currently planning for.

E. Summary

The Siting Council's mandated task is to review gas utilities' supply plans to meet forecasted sendout requirements to ensure adequacy, reliability, and minimum cost, taking into account the variability of sendout due to weather and other considerations. The Siting Council finds Westfield's plan to meet forecasted sendout requirements during a design year, a cold-snap period and peak day to be adequate and reliable for split years 1985/86 through 1987/88.

Given the uncertainty of Bay State LNG, the Siting Council cannot make a finding on the adequacy and reliability of the Department's supply plan in the latter years of the forecast period. The Siting Council has concerns about the ability of Westfield to meet

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32. The Siting Council notes several unexplained inconsistencies exist in the data for the cold-snap analysis. For instance, sendout requirements for 46 degree days exceed that of 47 degree days, and 63 degree days exceeds that of 69 degree days. However, even accepting that the sendout is underestimated there are sufficient resources to meet a cold-snap until 1988/89.

sendout requirements in the latter years of the forecast period should Bay State LNG not be available. In its next filing, the Department must address how it will meet sendout requirements in the latter years of the forecast period should Bay State not be available. Condition Three of this Decision addresses this issue.

Also, the Department performed a cost study which examined differing levels of MDQ for Tennessee pipeline gas. However, on the basis of evidence in the record before it, the Siting Council is unable to make a finding upon whether option A would be the minimum cost supply plan due to methodological flaws in the cost study.

VII. Impact of Order in Docket No. 85-64

The Siting Council's Order in Docket No. 85-64, along with new Administrative Bulletin No. 86-1, implementing that order, makes some changes in the filing requirements to be met by Massachusetts gas utilities in future forecast filings, beginning in 1986. For the Department's convenience, the changes which are most likely to affect its preparation of its next forecast filing are briefly outlined below.

A. Forecast Accuracy

The Siting Council is instituting a requirement that each gas utility report on the accuracy of its past forecasts, vis a vis actual normalized sendout for the same years. In addition, Westfield should examine whether the variability in its forecast of total sendout from year to year. The Department should address the cause of the variability in sendout forecasts.

B. Normalization Method

The Order in Docket No. 85-64 requires gas utilities to describe in detail and justify their approach to normalization of sendout for weather.

C. Design Year and Peak Day Selection

Administrative Bulletin 86-1 will require the gas utilities to provide a rationale for selection of design criteria. The Department should address the issue of the advantages of standards based upon a percentage deviation from a normal year's degree days over the recurrent probability standard it currently uses.

D. New Split Year

On the recommendation of many gas utilities, the Siting Council has determined that the split-year used for Siting Council reporting purposes should begin in November along with the heating season rather than in April. This change will affect all gas utilities, requiring them to recalculate the sendout for each historical base year in their forecast on a one-time basis, as well as to adjust the seasonal degree-day content of the years forming the basis of their normal and design year criteria. The Siting Council recognizes that this will cause some inconvenience in preparation of the 1986 forecast, but expects that over the long run the new split-year will improve the accuracy and reliability of gas utility forecasts.

E. Analysis of Cold-Snap Preparedness

The Order in Docket 85-64 requires that in their next filing, all large- and medium-sized utilities must submit either an analysis of their cold-snap preparedness or an explanation of why such an analysis is unnecessary to demonstrate that they will be able to meet their firm sendout obligations throughout a protracted period of design or near-design weather. These explanations of why such an analysis is unnecessary should discuss a utility's supply mix, inventory turnover practices, lead time for attaining supplemental supplies, and historical experience of equipment malfunctions, as well as the utility's experience in actual historical cold periods. If Westfield chooses to provide such explanations and through them be able to demonstrate satisfactorily that the Department's inventories and other supply capabilities are such that cold snaps do not pose a threat to its ability to meet firm sendout obligations, it may be excused from preparing such cold-snap analyses in the future, unless the Department's supply mix, inventory turnover practices, equipment performances, or lead times for acquiring supplies change.

F. Cost Studies

In the past, the Siting Council's review of a gas utility's supply plan has focussed primarily on a utility's ability to meet the requirements of its firm customers under normal and design weather conditions. In the past, the Siting Council generally has not compared or evaluated the costs of gas supply alternatives.

With a range of supply alternatives currently available at different prices, deliverabililty levels, and contract terms, the Siting Council must now ensure a gas utility's choice of supplies is consistent with the Siting Council's mandate to ensure "a necessary energy supply with a minimum impact on the environment <u>at the lowest possible cost</u>." Mass. Gen. Laws c. 164m sec 69H (emphasis supplied).

In this context, the Siting Council finds that in every forecast filing that indicates that the addition of a long-term firm gas supply contract is proposed within the forecast period, utilities are to perform an internal study comparing the costs of a reasonable range of practical supply alternatives. This requirement is intended to cover instances when the following types of contractual arrangements are proposed: (a) changes in or amendments to existing firm pipeline supply contracts or new firm pipeline projects; (b) changes in or amendments to firm gas storage contracts and for firm transportation of storage gas or new firm gas storage and/or transportation projects; (c) firm supplies of gas from a producer under a contract covering a two-year period or longer, along with related transportation arrangements; (d) any arrangement for supplemental gas supplies for which the supply is intended for use for a period longer than a single heating season, except for arrangements in which the utility can adjust the LNG volumes for the following heating season.

Westfield's cost study should address those methodological issues raised <u>supra</u> at 17 and 18. Specifically, the Department should properly document the assumption used in the analysis concerning degree days, gas prices, and load duration curve. Also, the Department should analyze normal and design years' condition in its cost study.

VIII. Order and Conditions

The Siting Council APPROVES the 1985 Supplement to the Second Long-Range Forecast of Gas Requirements and Resources of the City of Westfield Gas and Electric Department. Westfield shall be required to meet the five conditions listed below.

1. That Westfield file its next Supplement on or before October 1, 1986.

2. That Westfield explain and document how it uses its intimate knowledge and judgement to adjust its average number of customers, and base and heating use factors.

3. That Westfield provide a description of the status of its negotiations with Bay State for LNG and submit a contingency supply plan for meeting firm sendout requirements under normal year, design year, and peak day conditions should Bay State not be available in any of the forecast years.

4. That Westfield provide a description of its contract for pipeline gas under the Tennessee expansion project. Included in the description should be the status of the project before FERC, the MDQ and AVL Westfield expects to obtain, the provision that permits it to increase its MDQ, and the anticipated in-service date.

5. That Westfield satisfy the requirements outlined in the Siting Council's Order in Docket No. 85-64, Standards and procedures for Reviewing Sendout Forecasts and Suppley Plans of Massachusetts' Natural Gas Utilities, as described in Section VII.

Susan Fallows Tierney

Susan F. Tierney
Hearing Officer

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of August 7, 1986, by the members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs and

Business Regulation); Stephen Roop (for Secretary James Hoyte, Secretary of Environmental Affairs); Joellen D'Estri (for Secretary Joseph D. Alviani, Secretary of Economic Affairs); Joseph Joyce (Public Member, Labor); Dennis LaCroix (Public Member, Gas); and Madeline Varitimos (Public Member, Environment). Inelgible to vote: Elliot Roseman (Public Member, Oil); and Stephen Umans (Public Member, Electricity). Absent: Patricia Deese (Public Member, Engineering).

8-19-86
Date

Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Fall River Gas Company for Approval of the Fourth Supplement to its Second Long-Range Forecast of Gas Requirements and Resources	)	Docket No. 85-20

FINAL DECISION

Susan F. Tierney
Hearing Officer

On the Decision:
William S. Febiger

The Energy Facilities Siting Council ("Siting Council") hereby APPROVES subject to CONDITIONS the Fourth Supplement ("Supplement") to the Second Long-Range Forecast of natural gas requirements and resources for the years 1985/86 through 1989/90 ("the forecast period") of the Fall River Gas Company ("Fall River" or "the Company").

I. Introduction and History of the Proceedings

A. Background

Fall River distributes and sells natural gas to approximately 41,000 customers in the City of Fall River and the Towns of Somerset, Swansea, and Westport. Total firm sendout in the 1984-85 split year was 5494 million cubic feet ("MMcf"), which makes Fall River the fifth largest gas distribution utility in Massachusetts. Approximately 62 percent of the Company's firm sendout goes to residential heating customers, 22 percent to industrial customers, 9 percent to commercial customers, and 2 percent to residential non-heating customers. Between 1979 and 1984, Fall River's number of firm customers grew by 5.3 percent, though its weather-normalized firm sendout declined by 3.3 percent. Over the forecast period (1984 to 1989) Fall River projects that it will increase its number of firm customers by 4.3 percent, and that its normal firm sendout will expand by 14.2 percent.

B. Procedural History

The Company filed the Fourth Supplement to its Second Long-Range Forecast of natural gas requirements and resources on August 30, 1985. A Notice of Adjudication of the Supplement was issued and was published in accordance with the Hearing Officer's instructions. No petitions to intervene or motions to participate as an interested person were filed.

While consideration of the Supplement was pending, the Siting Council Staff issued a Notice of Inquiry into an Evaluation of Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Massachusetts Natural Gas Utilities ("the Notice of Inquiry") in Siting Council Docket No. 85-64. The purpose of this Notice of Inquiry was to solicit comments from all of the Massachusetts natural gas companies under the Siting Council's review process of gas company forecasts and how this process could be made more efficient and effective, and the Siting Council's decisions on those forecasts more meaningful to those companies.

The Notice of Inquiry established specific suggestions for changes in the standards and procedures to be followed by the Siting Council in gas company forecast proceedings. After requesting and receiving written comments on these suggestions, the Siting Council Staff held 10 days of hearings on the Notice of Inquiry in November, 1985. On November 13, 1985, Fall River appeared before the Siting Council Staff at the hearing to answer questions regarding issues raised in the Notice of Inquiry and the content of its current Supplement. Fall River's responses are referred to in this Decision (as "TR., 11/13/85, p. ______").

As stated in the Procedural Order of October 22, 1985 in Docket No. 85-64, the present Decision is made on the basis of the Siting Council standards and procedures which prevailed at the time the Supplement was filed. However, certain applicable changes to those standards and procedures evolving from the Notice of Inquiry are discussed in Section VI, infra.

The record in this Decision consists of the Supplement and transcripts of the hearing on the Notice of Inquiry in Siting Council Docket No. 85-64.

II. Compliance with Conditions

The Siting Council imposed five conditions in its last decision on Fall River's Third Supplement to its Second Long Range Forecast. In Re: Fall River, 12 DOMSC 11, 37-38 (1985). Fall River was ordered to:

1. Commence data collection efforts to support the selection of trends in base and heating factors in future forecasts.

2. Commence a program to improve data and documentation for the commercial and industrial classes.

3. Provide in its next filing the process and criteria used to evaluate new supplies and service contracts. Additionally, the Company shall provide in its next filing a detailed plan for balancing its resources and requirements in both the non-heating and heating seasons, if the F-4 volumes are approved. This plan should state Fall River's assumption regarding the future price of supplementals and the optimal levels of each supplement also that firm customers' requirements are met with an adequate supply at the lowest possible cost.

4. Develop an appropriate cold snap standard reflecting a realistic cold snap weather pattern and present it in the next Supplement. The standard should reflect the Council's concerns expressed herein.

5. Present in its next Supplement, an LNG contingency plan. The plan shall contain a statement concerning the reliability of DOMAC deliveries and a standard for determining when replacement supplies are needed and possible sources of those replacements.

Company officials met with the Siting Council staff on May 13, 1985 to discuss more specific efforts for complying with the conditions.

In response to Condition 1, the Company initiated a customer contact survey through its Service Department to ascertain connected-appliance saturation. In addition, the Company included in its forecast information on new construction, with associated gas penetration levels, and on oil-to-gas conversion trends in the Company's service area. The Siting Council finds that the Company has met Condition 1.

In response to Condition 2, the Company included some discussion of commercial activity leading to increases in sales. Although useful for background purposes, the Company's efforts do not inspire confidence that the Company is using or plans to use systematic methods to compile and interpret data on commercial activity. See Section III-E, infra. A number of ways in which the Company could develop systematic data were addressed in the compliance meeting with Siting Council Staff, but not significantly incorporated into the forecast. Letter from Eric J. Krathwohl to John Dalton, June 19, 1985. Thus, the Siting Council finds that Fall River has not shown that it commenced a "program to improve data and documentation for the commercial and industrial classes." The requirement is reimposed as the second condition in this Decision.

In response to Condition 3, the Company briefly presented the sequence of events and related reasoning underlying recent Company actions concerning major supplies, specifically the contracting of additional LNG from Bay State Gas Company and F-4 volumes from Algonquin Gas Transmission Company. However, the Company's documentation provided little if any insight on how The Company trades off cost with other factors, such as reliability. As such, the Company's efforts do not allow the Siting Council to determine how the Company's decision making on major supplies, as presented, might be generalized to address supply choices the Company might face in the future. Thus, the Company's response does not really constitute provision of "the process and criteria used to evaluate new supplies and service contracts." Nevertheless, the Company made an important start, and appears to have responded to some specific suggestions made in the compliance meeting with Siting Council Staff. Id. The Siting Council's Order in Docket 85-64 includes important provisions which will relate to Fall River's presentation of its decision making process concerning certain classes of possible future supplies. See Section VI, infra.

With respect to the balancing of resources and requirements, also addressed in Condition 3, the Forecast indicates that Fall River expects to negotiate reductions in its contracted LNG volumes from Bay State. Accordingly, within the context of the current filing, the Siting Council finds that Fall River has met the condition that it provide a plan for balancing its resources and requirements. See Sections V-A and V-B, infra.

The Siting Council finds that Fall River has met the requirements of Condition 4, concerning a new cold snap standard. See Section V-D, infra.

The Siting Council finds that Fall River has met the requirements of Condition 5, concerning provision of an LNG contingency plan.

III. Analysis of the Forecast

A. Introduction

Table 1 shows Fall River's forecast of sendout requirements for the 1985-86 and 1989-90 split years.

In this Supplement, Fall River continues to forecast its sendout requirements with the use of base factors, heating factors, and degree-day data. The Siting Council has approved this forecasting approach as basically sound in previous decisions on the Company's filings. In this Decision the accuracy of the Company's past forecasts, as made in the two most recent filings, now is reviewed as well. Section B, infra.

With respect to the methodology itself, the Decision does not repeat descriptions contained in the previous decisions or in the Supplement itself. Instead, the Siting Council concentrates on implications of the Order of Standards and Procedures for the Company's methodology, and on aspects of the methodology that the Company has changed since its previous filing. The issues addressed include: the Company's method of selecting degree-day standards for normal and design weather; the methods of projecting base and heating factors; the basis for projecting the number of customers; and judgmental adjustments to the forecast of commercial and industrial usage. See Sections C through E, infra.

B. Forecast Accuracy

The Siting Council is interested in reviewing the accuracy of gas company forecasts, based on comparisons of firm normalized sendout in historical split years with the normalized firm sendout that had been forecasted for such years in past Siting Council forecasts. In this review, the Siting Council has considered Fall River's forecast accuracy for the two most recent historical years (1983-84 and 1984-85) and the two most recent supplement filings (1983 and 1984). See Table 2.

In its 1983 filing, Fall River under-forecast split-year sendout for the first two forecast years by approximately 10 to 12 percent. As shown in Table 2, the differences are apparent in both the heating and non-heating season. A review of Fall River's class sendout tables suggests that the discrepancies also are attributable to a number of classes (in absolute terms, the residential heating and industrial classes appear most significant) and to both customer numbers and usage factors within various classes. Indeed, the coincidence of both an economic upturn and a reduction in gas prices appears in hindsight to have compounded the extent of the upturn in sendout that needed to be anticipated for an accurate forecast. Also, with respect to Fall River's sizable industrial process-use load, a strong shift of sendout from a firm to an interruptible basis, which had begun in 1981-82, stabilized dramatically in 1983-84.

In the 1984 filing, Fall River again under-forecast split-year sendout for the first forecast year, but by a much smaller margin of less than 2 percent. The discrepancy is essentially confined to the

Table 1

Forecast of Sendout by Customer Class
(MMCF)

	1985-86 Non-heating Season	1985-86 Heating Season	1989-90 Non-heating Season	1989-90 Heating Season
Normal Weather				
Residential				
Heating	1127	2514	1179	2630
Non-heating	53	47	51	45
Commercial	153	340	158	352
Industrial	657	684	749	779
Co. Use and Unaccounted-for	(4)	240	(2)	240
Total Firm	1989	3825	2136	4046
Interruptible	842	150	842	150
Total Sendout	2831	3975	2978	4196
Design Weather Total Firm	2109	4022	2261	4268
Peak Day Sendout Requirements		51.1		54.1

Source: Supplement, Tables G-1 through G-5. Columns may not add due to rounding.

Table 2

Forecast Accuracy, 1983 and 1984 Filings

	Non-Heating Season (MMcf)	Heating Season (MMcf)
1983 Filing:		
1983-84 Projected	1734	3380
1983-84 Actual	1905	3724
Absolute Difference	-171	-394
Percent Difference	-9.0	-10.4
1984-85 Projected	1725	3374
1984-85 Actual	1929	-3789
Absolute Difference	-204	-442
Percent Difference	-10.6	-11.7
1984 Filing:		
1984-85 Projected	1928	3693
1984-85 Actual	1929	3789
Absolute Difference	-1	-96
Percent Difference	-0.1	-2.5

heating season and appears to be primarily attributable to the heating use factor projection for the residential heating class.

C. Degree-Day Standards

Fall River uses the following degree-day ("DD") totals to calculate its sendout requirements:

	Non-heating Season	Heating Season	Total Split-year
Normal Weather	1372	4751	6123
Design Weather	1543	5100	6643

The design peak day is 74 degree days. All of the DD values are based on weather data since 1963-64.[1]

The DD totals for normal weather are the mean values for each season after deletion of outlying data points as shown in Figure 1. The Company discards four outliers before calculating the average DD in a non-heating season, and discards one outliers before calculating the average DD in a heating season.[2]

The Siting Council previously determined that the Company's normal weather DD standards, including its judgemental deletion of outlying data points, are appropriate. 12 DOMSC 11, 15. As discussed below, however, the Siting Council now seeks a fuller discussion of the rationale underlying Fall River's methodology.

The DD totals for design weather are the maximum values actually experienced during non-heating seasons and heating seasons since the 1963-64 split year. The peak day DD value of 74 is based on the recorded maximum DD value of 69 (from 1980-81) plus a 5 DD safety margin.

The Siting Council previously determined that the Company's design weather DD standards are appropriate, but noted that other more analytical approaches could be used as well. 12 DOMSC 11, 16. In that review, the results of a staff analysis of the statistically expected frequency with which the Company's design standards will recur were

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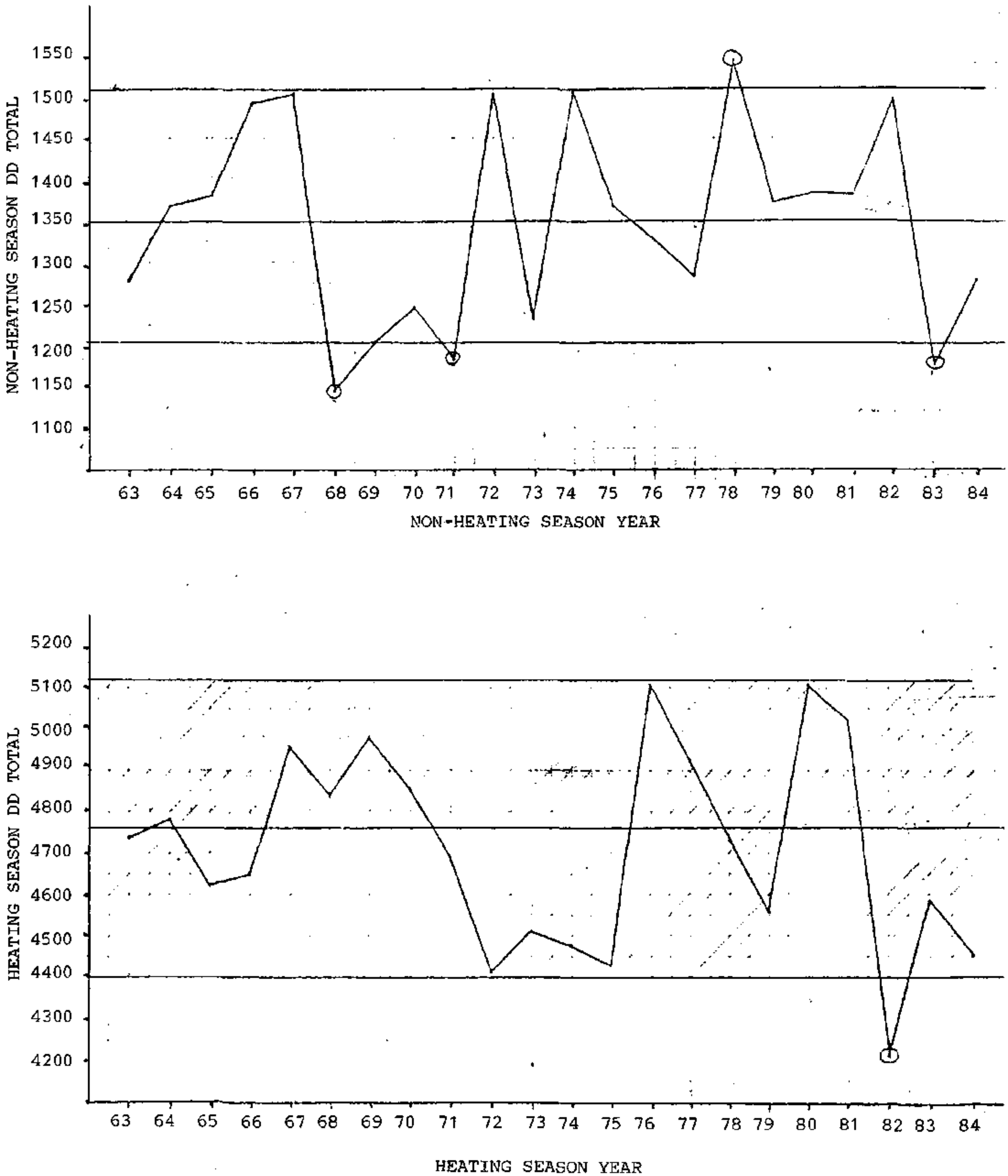
[1]The Company has not recalculated normal weather DD, since its previous filing, to reflect the additional weather year, 1984-85, reported in the current filing (and shown in Figure 1).

[2]The resulting weighted averages yield higher normal year DD standards than would result from the usage of unadjusted averages. For the non-heating season, the weighted average closely approximates the median value for the 21 years of data. The median values are 1370 DD for non-heating seasons and 4735 DD for heating seasons, while the mean values are 1351 DD for non-heating seasons and 4725 DD for heating seasons.

Figure 1
Degree - Days by Year



Source: Supplement, Exhibits A and B

available to assist the Siting Council's findings.[3] As discussed below, the Siting Council now is concerned that the recurrence frequency of design weather should be explicitly recognized on a regular basis in gas forecasts.

In its Order under Docket No. 85-64, the Siting Council has reaffirmed its interest in monitoring the design criteria that each gas company uses in its supply planning to ensure that those criteria bear a reasonable relationship to design conditions that are likely to be encountered. <u>See</u> Section VI, <u>infra.</u> In order to facilitate this assessment of reasonableness, a Company's methodology must be reviewable.

Accordingly, the Company is expected, in future forecast filings, 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. The Siting Council also encourages the Company to expand its historical weather data base, including, in particular, data for the most recent weather year(s) newly available since previous filings.

The Siting Council also observes that the Company's methodology for deriving DD totals for normal weather, involving the deletion of outlying data points, may be viewed as bearing some relationship to the concept of recurrence frequency.[4],[5] At present, the Company's basis for drawing amplitude bands, as shown in Figure 1, is judgemental. However, the reviewability of the technique could be improved if such bands were

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[3]It was shown that, assuming normally distributed data, the Company faces a probability of 0.0559 (1 in 18) of a colder-than-design heating season, and a probability of 0.0099 (1 in 100) of a colder-than-design split year. 12 DOMSC 11, 16. It should be noted that the design split year is based on the sum of non-coincident maximum of the heating and non-heating seasons (i.e., not an actual whole year).

[4]Under such an interpretation, the outlying data points would have a recurrence frequency that is less than a specific limit (or outside a band on the graph in figure 1). It might be reasoned, for example, that such an outline should be treated separately based on an expectation that it would occur less than once every twenty-one years, which is the length of the overall available data base.

[5]The Company noted another beneficial result of its normal weather DD methodology, beyond that of removing data points not expected to occur very frequently. With respect to the non-heating season, the methodology allowed the Company to derive a standard better reflecting "the density of the locus of points favor(ing) the area of the plot above the arithmetic average." Supplement, First page. The Company indicated that it had not considered whether use of the median rather than the mean could accomplish this purpose more effectively. Tr., 11/13/85, p. 94-97.

described in terms of a recurrence frequency.[6] The Siting Council requests that, in the event that the Company elects to retain this methodology in future filings, recurrence frequencies be explicitly recognized and provided with the results, or an explanation provided as to how the rationale for the methodology differs from or is unrelated to the concept of recurrence frequency.

D. Base and Heating Factor Projections

Fall River projects base and heating use factors for its residential sendout forecast through the use of trends selected on the basis of judgement. In the current forecast, the Company assumes that base factors will cease declining, and that base and heating factors will level out near their 1984-85 values as shown below:

		Historical		Forecast	
Customer class	Factor	1983-84	1984-85	1985-86	1989-90
Res. Non-Heating	Base	17.1	16.9	16.8	16.6
Res. Heating	Base	27.7	26.0	26.0	26.0
Res. Heating	Heating	0.0135	0.0137	0.0136	0.0136

Note: Base factors are given in units of Mcf per customer. Heating factors are given in units of Mcf per DD per customer.

Source: Forecast, Tables G-1 and G-2.

The Company states that it considers the impacts of appliance efficiency, conservation, and fuel cost expectations in its selection of use factor trends, but does not present quantitative studies of these impacts. The Company reports it has proceeded to collect data on appliance use by its residential customers, in response to the Siting Council's previous condition concerning development of data to support use factor projections. The Company states that the survey data, which is being compiled by Company Service Department personnel as part of their normal contact with customers, will be used as appropriate in future forecasts.

The Siting Council commends the Company's effort in commencing the development of service area data on residential appliance use. However, the Siting Council recognizes that the current survey consists of a simple checklist of appliances, and does not appear to address other related analytical factors suggested in the previous decision as

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[6] For the heating season, the band width in Figure 1 appears to be based on the same data point which is the basis for the design year standard. Thus, the calculated recurrence probability of 0.0559 (1 in 18), made by the Siting Council staff in EFSC 84-20, would apply. See Footnote 3.

possible areas of data development that would be appropriate.[7] In addition, the Company has not clearly set forth the planned sampling design (i.e, such factors as the time period to conduct the survey and the percent of the population to be surveyed), nor how the sampling design was selected.

Regarding its ability to project use factor changes based on current conditions and information, the Company stated that "throwing net changes in for this forecast period would have just been cosmetics, to make it look like there was some grand analysis." Tr., 11/13/85, p. 102. At the same time, the Company acknowledged that the base and heating use factors for its heating customers have been "moving apart, the last couple of years." Id. Nevertheless, given the available data, the Company elected to project use factors as remaining constant over the entire forecast period for heating customers, and over the last three years of the forecast period for non-heating customers.

The Siting Council continues to believe the Company should have a good understanding of the relative trends in base and heating use factors, and a greater confidence in its own ability to project such factors than has been found to exist in the current review. The Siting Council looks forward to the prospective documentation and analysis of the appliance use survey results in the Company's next and future filings, and the greater forecasting confidence such results hopefully will be able to instill.

The Siting Council recognizes that a long-term implementation program may be required to address the data development concerns outlined in the previous decision with respect to forecasting base and heating use factors. Accordingly, the Siting Council CONDITIONS its approval of Fall River's sendout forecast on the presentation in the next forecast of a report on progress to date concerning documentation of use factor levels, and how such efforts fit into a long term approach to data development supporting use factor projections. The report should build on the results of the Company's appliance survey, and clarify what additional data development efforts are planned, how such efforts will address average use per appliance and factors that influence appliance ownership and usage, and what sampling techniques are planned or under consideration.

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[7] The previous Decision stated that appropriate data collection efforts might include formal surveys of the number of appliances owned by the Company's present and future customers, the average use per appliance, and factors that influence appliance ownership and usage by residential heating and non-heating customers. The Decision also identified appropriate types of follow-up study that might be based in part on results of such surveys, including economic studies of the relationship between price and base factors or heating factors, and closer examination of residential heating consumption patterns and the price and temperature-sensitivity of residential non-heating load.

E. Commercial and Industrial Usage Changes

The Company prepares separate forecasts of commercial and industrial sendout, based on regular contact with customers by Company personnel and historical levels of base and heating use. Since the previous filing, the Company has made no changes in its forecast methodology, but has made some limited changes in the documentation and narrative presentation of its forecast.

After showing a relatively sharp increase of 11.0 per cent between 1982-83 and 1983-84, Fall River's average normalized use per commercial customer increased again between 1983-84 and 1984-85, but at a more modest 3.6 percent rate. Average normalized use per industrial customer dropped 3.6 percent between 1983-84 and 1984-85, reversing a more sizable jump of 16.3 percent in the year before.

The Company's forecast of commercial and industrial sendout continues to reflect the projection of base and heating factors at constant levels, based on five-year historical averages. Reflecting this moving average, the industrial base and heating factors have been decreased by 1.6 percent and 1.0 percent, respectively, since the previous forecast. The commercial base and heating factors have been increased by 1.1 percent and 4.5 percent, respectively, since the previous forecast.

In response to the Siting Council's previous condition concerning documentation of commercial and industrial use, the Company states that ongoing means of data collection -- including regular customer contact by service personnel and involvement in Chamber of Commerce activities and the Redevelopment Authority -- are being increased. However, documentation of the results of such efforts in the Forecast remains limited, consisting of a few paragraphs citing instances where new or converted gas heating or cooling is occurring (square-footage of floor space indicated) and aggregate statistics on 1984 and 1985 (to date) gas air conditioning penetration (in tons). Supplement, section headed "Commercial/Industrial."

Fall River's forecast of commercial and industrial sendout raises concerns on several levels. First, the very organization and format of Fall River's presentation of background information on trends and other factors affecting its forecast (the section headed "Commercial/ Industrial") does not inspire confidence that the Company's approach is systematic or analytical. The reviewability of the narrative could be greatly enhanced by separate discussion of the commercial and industrial classes, by use of tables to present penetration data for customers or customer types, and by expression of penetration or similar information in units comparable to those in the forecast tables (i.e., sendout volumes).[8] Given the Company's reliance on regular customer contact for

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[8]After a compliance meeting on May 13, 1985, it was indicated that (Footnote Continued)

documentation purposes, organization and interpretation are essential in communicating or applying information about the service area as part of the forecast.

Second, the Company has not identified specific steps taken or proposed to enhance the depth or analytical usefulness of the information that it gathers about its customers. The Company does report that it maintains data by Standard Industrial Classification (SIC) code for certain process-use industries. Tr., 11/13/85, p. 78. However, the Company has not shown that it uses or plans to use systematic and standardized survey techniques to compile information about the characteristics and usage patterns of its commercial and industrial customers and about any year-to-year changes and trends. Nor does the Company demonstrate any consideration of the relationship of its industrial sales to macroeconomic variables at the regional or national levels.

The forecast narrative does suggest the existence of factors which Fall River evidently believes are important for its forecasting of commercial and industrial sales. Such factors include the nationwide contraction of the textile industry, opportunities for gas-fired heating in commercial redevelopment of old mill properties, and improved potential for gas air conditioning penetration with more efficient equipment. Supplement, Section headed "Commercial/Industrial". The Company foresees the net effect of all these factors "resulting in minimum of possibly negative growth in our industrial market." Id.

Overall, the Siting Council finds that the Company's narrative does not provide a reviewable basis for the derivation of the customer and usage factor projections that make up the commercial and industrial forecasts. The limited reviewability is of special concern for the commercial class this year, as the Company appears to see clearly upward trends there (supra), but does not provide an explanation for the relative reflection of these new trends in respective adjustments to the customer and usage-per-customer projections since the previous filing. With respect to the industrial class, the Company continues to lack analytical methods for identifying possible factors which could predict the sometimes volatile trends in industrial sendout.

The Siting Council concludes that Fall River must take significant steps to begin improving the documentation of its commercial and industrial forecast, as it reportedly has done with respect to its residential forecast. Such steps were ordered in the previous decision, and the Company is hereby informed that the forecast must show progress in order to be approved in the future. Accordingly, the approval of the current sendout forecast is CONDITIONED on the commencement of a program

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(Footnote Continued)
the Company understood it should present more detailed information regarding new development that will use gas, including on-line date and expected usage. Letter from Eric J. Krathwohl to John Dalton, June 19, 1985.

to improve Fall River's data and documentation regarding its sendout forecasts for the commercial and industrial classes. The program must include a standardized survey or such other reviewable approach as the Company may propose to assess its customer make-up and usage patterns, and identify related trends.

IV. RESOURCES AND FACILITIES

In the past, the Siting Council has focused primarily on a gas Company's ability to meet the requirements of its firm customers in reviewing that company's supply plan. A company's ability to meet firm peak day and normal and design weather requirements was the Siting Council's major supply planning concern. In the past, the Siting Council generally has not compared the costs of gas supply alternatives.

With a range of supply alternatives currently available at different prices, deliverability levels, and contract terms, the Siting Council must now ensure a gas company's choice of supplies is consistent with the Siting Council's mandate to ensure "a necessary energy supply with a minimum impact on the environment at the lowest possible cost." Mass. Gen. Laws Ann. ch. 164, sec. 69H (emphasis supplied). In the previous decision, the Siting Council stated its intent to review each company's basis for selecting a supply alternative or the Company's decision process to ensure that its decisions are based on projections based on accurate historical information and projection methods.

In reviewing Fall River's current Supplement, the Siting Council has examined, as before, the adequacy of Fall River's supplies to meet firm requirements under normal and design weather conditions, and peak day and cold snap conditions. The Siting Council generally is satisfied that Fall River has sufficient supplies under these conditions.

To the extent possible based on the existing record, the Siting Council has reviewed Fall River's supply plan to determine whether the Company's plan ensures a necessary supply at the lowest possible cost. Fall River's filing itself contained little information to assist the Siting Council in this latter task. In response to the Siting Council Staff's questioning on this issue, Company witnesses indicated that cost analysis with respect to new supplies is "done in the treasurer's office or the accountant's office or the president's office," but were unable to provide much additional insight as to the nature and methods of such cost analysis. Tr., 11/13/85, p. 42. Thus, the Siting Council is unable to draw definite conclusions on whether Fall River's supply plan observes the least cost mandate consistent with providing reliable supplies. The Siting Council is again providing notice of the intended scope of future proceedings and of the type of information which the Siting Council will require. *See* Section VI, *infra*.

A. Overview

Fall River's resources and facilities are substantially the same as those described in the Siting Council's most recent Fall River Decision. 12 DOMSC 11 (1985). Therefore, this section will focus primarily on the changes in the Company's supply plan since the previous Siting Council decision. Fall River's currently effective supply agreements are shown in Table 3.

In summary, the Algonquin Gas Transmission Company ("Algonquin") provides the Company with pipeline gas under four separate contracts: firm gas service on a year-round-basis under the F-1 service agreement; firm winter service gas, available from November 16th through April 15th, under the WS-1 service agreement; underground storage and transportation service under the STB-1 service agreement; and SNG under the SNG-1 service agreement. In addition to these service agreements, Fall River recently began receiving firm pipeline volumes from Algonquin under the F-4 rate schedule and signed a service agreement with Algonquin which provides an increase in storage transportation service under the SS-III rate schedule.

The Algonquin F-1, and WS-1, and the Bay State LNG agreements are scheduled for initial expiration within the forecast period. Fall River is expected to discuss in detail its plans for future contracts for each of these supplies.

B. F-4 Service

In December, 1985, Algonquin began providing Fall River with additional pipeline service on a 365-day basis under Rate Schedule F-4 Interim, consisting of an MDQ of 1.7 MMcf and an AVL of 610 MMcf. Full firm service is scheduled to begin November 1, 1986, under which Fall River would have an MDQ of 3.75 MMcf and an AVL of 1,370 MMcf.[9] Expansion of the Texas Eastern Transmission Company ("Texas Eastern") supply system was needed before the interim firm service could be provided, and two short looping segments are required by Algonquin in Massachusetts before firm service can commence.

In justifying the F-4 purchase, the Company points primarily to the need to replace the SNG volumes, which have been dramatically reduced

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[9] Algonquin Gas Transmission Co., FERC Docket No. CP84-654-001, "Amendment to Abbreviated Application for Certificates of Public Convenience and Necessity for (i) Limited Term Interruptible Sales Service and (ii) Long-Term Sales Service." Algonquin is acquiring the necessary supplies from Texas Eastern Transmission Corporation which in turn is acquiring the supplies in the same stages from Columbia Gas Transmission Corporation. FERC Docket No. CP84-429-001. Algonquin has recently petitioned FERC to amend its certificate in order to reflect a new delay in full firm service until November 1, 1987, necessitated by construction delays, and to authorize "development period service" during 1986-87. The proposed development period service would be approximately 84 per cent of full service, and for Fall River would amount to a MDQ of 3.15 MMcf and an AVL of 1151 MMcf. FERC Docket No. CP84-654-016, "Notice to Amendment and Petition to Amend", September 15, 1986.

Table 3

Fall River Gas Company

Current Gas Supply Agreements

Supplier	Contract	AVL/ACQ (MMcf)	MDQ (MMcf)	Cost[1] ($/Mcf)	Contract Dates	Transportation
Algonquin	F-1	3,958.2	14.6	3.19	11/69-11/89	Algonquin Pipeline
Algonquin	F-4	610.3	1.7	3.55	12/85-10/86	Algonquin Pipeline
		1,369.5	3.8		11/86-10/2006	
Algonquin	WS-1	427.2	7.1	3.42	11/68-11/88	Algonquin Pipeline
Algonquin	SNG-1	108.5	1.0/2.5[2]	21.25	4/85-4/86	Algonquin Pipeline
		93.0	1.0/2.5[2]		4/86-4/87	
Algonquin	ST-1	180	1.8	7.85	4/80-4/2000	Algonquin Pipeline
	SS-III	95	0.95[4]		8/86-4/2000	Algonquin Pipeline
DOMAC	Firm	435	-	7.05[3]	4/71-4/91	Truck
Bay State	Firm	263	-	7.05[3]	9/82-4/87	Truck
		788			4/87-4/88	
Bay State	Optional	87	-	7.05	9/82-4/86	Truck
		262			4/87-4/88	
Petrolane	Firm/Contract	125	-	6.96	4/85-4/90	Truck
Petrolane	Optional	18.7	-	6.96	4/85-4/90	Truck

1. Cost is based on the Company's Cost of Gas Adjustment filing with the Department of Public Utilities for April 1, 1986. This cost represents a 12-month rolling average as provided in CGAC filings.
2. Lower figure is MDQ for December 10-31 and February 1-15; higher figure is MDQ for January 1-31.
3. The Cost of Gas Adjustment filing does not differentiate between the costs of DOMAC and Bay State LNG. Only the average cost for LNG is provided.
4. Best efforts basis.

Source: <u>Forecast</u>, Table G-24.

over the last two years and are expected to be totally removed in 1987. See Section D, infra. Fall River has viewed the F-4 purchase not only as being more economic than SNG, but also as providing superior economics and reliability when compared to other SNG replacement options such as additional Bay State LNG. Supplement, Section headed "G-22: Resources and Requirements".

The Company acknowledges that it previously contracted with Bay State for 788 MMcf of LNG beginning in 1987, essentially to replace the SNG loss. Now that the F-4 supplies have been obtained as well, the Company believes it will be in a position to back off propane beginning in 1987, and probably also will pursue negotiations, as possible, to back off part of its firm LNG supplies in that year. Id.

With regard to the sizing of the F-4 purchase, the Company states "we probably would have gone for a little more F-4, but it was sized on a pro-rata basis to the customers of the pipeline." Tr., 11/13/86, p. 33. The Siting Council notes that the F-4 customers, including Fall River, were recently offered some additional volumes; Fall River elected to take an additional 92 MMcf.

The Siting Council previously has supported the Company's F-4 purchases, and reaffirms that support at the slightly higher volumes. The Company is reminded, however, that the Siting Council expects future supply acquisitions to be supported by cost comparisons for a range of viable options. See Section VI, infra.

C. Algonquin Storage Service: SS-III

The Company has also signed a precedent agreement which provides a 95 MMcf increase in annual storage service from Algonquin as of April 1, 1986. An additional 0.95 MMcf in daily storage gas deliveries also is provided, but on a best efforts basis. To provide these services Algonquin has contracted with Texas Eastern, which in turn has contracted for the underlying storage service with the Consolidated Gas Transmission Corporation.

Thus, these additional resources increase the Company's seasonal, peak day, and cold snap delivery capability and hence increase the reliability of the Company's resources.

D. SNG Volume Reductions and Expiration of the SNG-1 Contract

Given the high cost of SNG relative to other available resources, the Company has reduced its SNG takes to 108.5 MMcf for the 1985-1986 heating season, a 65 percent reduction below the contracted volume for the previous year. After a further reduction to 93 MMcf forecast for the 1986-87 heating season, no SNG volumes are shown by the Company after the 1986-87 heating season. Algonquin has filed an application with FERC to abandon its SNG service, and plans to dismantle its SNG plant. In Re: Algonquin SNG, 14 DOMSC _____, 2 (1986).

E. LNG Volumes

Fall River's forecast includes firm LNG volumes from both Distrigas of Massachusetts Corporation ("DOMAC") and Bay State Gas Company. DOMAC ia a major supplier of LNG to Bay State. Distrigas Corporation ("Distrigas"), the parent company of DOMAC, has filed for bankruptcy thus creating uncertainty about the reliability of DOMAC as a source of supply. In a recent decision, the Siting Council questioned the reliability of LNG supplied by DOMAC. In Re Bay State Gas Company, 14, DOMSC ___, 26 (1986). Since Fall River includes LNG volumes from Bay State in its supply plan, and the reliability of supply of LNG to Bay State from DOMAC is uncertain, the Siting Council also regards the reliability of Bay State LNG supply as uncertain.

The Supplement indicates that Fall River expects to negotiate reductions in its contracted LNG Volumes from Bay State for 1987-88. See Section V-A, infra. Even with such reductions, however, Fall River would rely on LNG from both DOMAC and Bay State to meet up to 866 MMcf of its design year needs by the end of the forecast period.

Fall River provided, for the first time, an LNG contingency plan with the current filing. However, the contingency plan does not recognize the uncertainty of Bay State LNG Volumes. Accordingly, the siting Council ORDERS Fall River to include in its next filing an update on its contingency plan for LNG. The discussion shall include: the status of the Distrigas and DOMAC federal government applications; the impact of Order No. 380 on DOMAC's ability to supply Bay State with LNG and the resultant capability of Bay State to supply Fall River with LNG; the status of any negotiations with Bay State, and as appropriate with DOMAC, relating to reductions in Fall River's firm LNG suppliers; and identification of other potential suppliers of LNG, and possible terms of delivery.

F. Conservation Programs

The Siting Council expects companies to evaluate conservation programs as a supply source on the same basis as other supply sources. The Siting Council considers such programs to offer a potential contribution to ensuring necessary gas supplies at the lowest possible cost with a minimum impact on the environment. Mass. Gen. Laws Ann. ch. 164, sec. 69H.

The Company states that it elected to project both base and heating use factors for the residential class on a levelized basis (See Section III - D, supra) because "it doesn't seem to have done much good to..., in the past, project conservation." Tr., 11/13/85, p. 104. The Company has not conducted any studies to identify trends in implementation of residential conservation. Id. With respect to the commercial and industrial class, the Company reports that it has no specific information on implementation of conservation by customers, and that regular customer contact by Company service personnel generally could have been expected to discover such implementation. Id., p. 104-106.

The Siting Council believes that, at a time when Fall River has supply alternatives and must plan for new contracts, conservation should receive concurrent attention. The Siting Council notes that there may be Company-sponsored conservation programs which, in conjunction with other supply resources, could reduce total supply costs below what it costs to supply customers without such conservation. Conservation programs, like other supply options, may require some lead time for effective implementation. Accordingly, the Siting Council expects Fall River to begin addressing such programs and their potential impacts and cost-effectiveness on system supplies, as a regular part of its forecast filings. As a CONDITION for approval of its current Forecast, Fall River shall provide in its next filing a description of how it has been evaluating the impact that conservation could have on its system supplies. This description shall consider the residential, commercial, and industrial sectors separately.

V. COMPARISON OF RESOURCES AND REQUIREMENTS

Since the previous Siting Council review, Fall River's development of new supplies, in particular the F-4 pipeline service, has been realized largely according to plan. At the same time, Fall River's current sendout forecast shows some upward revisions since the previous filing. In the later years of the forecast period, the upward revisions in forecast sendout absorb about half of the increase in supply that is being provided through the interim and full F-4 service for the heating season, and close to a quarter of that that is being provided for the non-heating season.

The previous Decision contained detailed descriptions of Fall River's balancing of sendout and supplies, both with and without the F-4 service. F-4 service appears to be assured now,[10] and other aspects of the supply plan are largely unchanged. The planning contingencies that do affect Fall River's forecast -- for example, the status of the proposed SS-III storage service and uncertainty about future LNG takes under the DOMAC contract -- do not appear to be critical for enabling the Company to meet its firm requirements over the forecast period.

A. Normal Year

Table 4 displays Fall River's requirements and resources during a normal year with the currently effective supply contracts, and the proposed SS-III storage service.

For the non-heating season, the introduction of F-4 service allows Fall River to reduce its reliance on interruptible pipeline supplies from about 900 MMcf in 1985-86 to 700 MMcf in 1986-87 (Interim F-4 service) to 300 MMcf in 1987-88 (Full F-4 service).

For the heating season, nearly 200 MMcf of spot and optional supplementals are needed, in conjunction with Interim F-4 service, in 1985-86. However, with the introduction of Full F-4 service and a

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[10] Construction delays could limit the planned increase in F-4 volumes in 1986-87. See Footnote 9.

Table 4

FALL RIVER GAS
COMPARISON OF RESOURCES AND REQUIREMENTS
NORMAL YEAR
(MMcf)

REQUIREMENTS	Non Heating 1985-86	Heating 1985-86	Non Heating 1986-87	Heating 1986-87	Non Heating 1987-88	Heating 1987-88	Non Heating 1988-89	Heating 1988-89	Non Heating 1989-90	Heating 1989-90
Normal firm sendout	1,989	3,825	2,028	3,887	2,067	3,945	2,104	4,000	2,136	4,046
Interruptibles	842		842		842		842		842	
Fuel reimbursement		10		13		13		13		13
Storage refill:										
Underground	127		241		206		206		206	
Propane		37		37		37		37		37
Liquefaction										
LNG	120		120		120		120		120	
TOTAL	3,078	3,872	3,231	3,937	3,235	3,995	3,272	4,050	3,304	4,096
RESOURCES										
AGT F-1	1,900	2,040	1,900	1,944	1,900	2,040	1,900	2,040	1,900	2,040
F-4		252	358	567	803	567	803	567	803	567
WS-1	70	357	70	357	70	357	70	357	70	357
SNG-1		109		93						
AGT Interruptible	898		693		252		289		321	
AGT Storage Return		146		206		206		206		206
LNG from storage		120		120		120		120		120
DOMAC LNG	210	225	210	225	210	225	210	225	210	225
Bay State LNG		263		263		318		373		419
Optional Bay St. LNG		87		0						
Spot LNG		46								
Propane from storage		37		37		37		37		37
Firm propane purchases		125		125		125		125		125
Optional Propane		0								
Spot propane		65		0		0		0		0
TOTAL	3,078	3,872	3,231	3,937	3,235	3,995	3,272	4,050	3,304	4,096

Dispatch assumes 1) LNG and underground storage are filled to capacity in non-heating season.
2) Fall River attempts to take full volumes under firm contracts. Thereafter, Fall River will send out supplementals as required while attempting to minimize costs.
3) Propane volumes in storage will be used during the heating season and will be replaced as used.
4) After the 1986-87 Heating Season Fall River will be able to reduce its Firm Bay State LNG quantities to balance load.
5) Fall River is required to remove 75% of its storage gas in any contract year. Therefore, storage return resources must be at least 75% of the Company's storage capacity. Additional resources are dispatched on a cost basis.
6) F-4 volumes are 100% take-or-pay.
7) Fall River's WS-1 contract is extended at least two years under current terms.

planned increase in pipeline storage return in 1986-87, not only can the non-firm supplementals be dropped, but nearly 100 MMcf of F-1 service will be refused as well. For 1987-88, Fall River has contracted for a 525 MMcf increase in its firm LNG supply from Bay State, resulting in a normal year oversupply of firm resources approaching 500 MMcf. Rather than continuing or increasing normal year refusals of F-1 supplies, the Company expects to negotiate LNG reductions for 1987-88 substantially reversing the contracted increase from Bay State.

The Siting Council is requiring that the Company report fully on the status of any negotiations relating to LNG reductions and provide an update on its LNG contingency plan in its next filing. See Section IV-E, *supra*.

B. Design Year

Table 5 displays Fall River's requirements and resources during a design year with the currently effective supply contracts, and the proposed SS-III storage service.

For the non-heating season, Fall River's design firm sendout is about 125 MMcf higher than its normal firm sendout. In addition, the Company assumes receipt of little or no interruptible pipeline supplies under design conditions for the last four years of the forecast period. In 1986-87, resources and requirements are essentially balanced without any volumes being available for sales to interruptible customers. (In a normal year, interruptible sales are 842 MMcf.) However, the introduction of Full F-4 service in 1987-88 makes possible over 450 MMcf of design year interruptible sales, gradually declining as design firm sendout rises over the remainder of the forecast period.

For the heating season, Fall River's design firm sendout is about 200 MMcf higher than its normal firm sendout. In 1985-86, this difference is made up by taking supplementals, while in 1986-87 the difference is made up partly by taking supplementals and partly by not refusing nearly 100 MMcf of F-1 pipeline supplies. See Section V-A, *supra*. In the latter three years of the forecast period, the difference is made up by increased takes of LNG. However, these planned LNG volumes still represent partial deliveries of contracted firm supplies from Bay State and DOMAC, and thus must be viewed as subject to negotiation. See Section V-A, *supra*. The surplus of the Company's currently contracted firm resources above its requirements for a design heating season is about 260 MMcf in 1987-88, decreasing to just under 150 MMcf in 1989-90.

The Siting Council is requiring that the Company report fully on the status of any negotiations relating to LNG reductions and provide an update on its LNG contingency plan in its next filing. See Section IV-E, *supra*.

C. Peak Day

Fall River must have sufficient daily pipeline supplies, supplemental storage and sendout facilities to meet the requirements of

Table 5

FALL RIVER GAS
COMPARISON OF RESOURCES AND REQUIREMENTS
DESIGN YEAR
(MMcf)

REQUIREMENTS	Non Heating 1985-86	Heating 1985-86	Non Heating 1986-87	Heating 1986-87	Non Heating 1987-88	Heating 1987-88	Non Heating 1988-89	Heating 1988-89	Non Heating 1989-90	Heating 1989-90
Design firm sendout	2,109	4,022	2,150	4,091	2,190	4,156	2,229	4,217	2,261	4,268
Interruptibles	0		0		467		428		396	
Fuel reimbursement		10		13		13		13		13
Storage refill:										
Underground	127		275		206		206		206	
Propane		37		37		37		37		37
Liquefaction										
LNG	120		120		120		120		120	
TOTAL	2,356	4,069	2,545	4,141	2,983	4,206	2,983	4,267	2,983	4,318
RESOURCES										
AGT F-1	1,900	2,040	1,900	2,040	1,900	2,040	1,900	2,040	1,900	2,040
F-4		252	358	567	803	567	803	567	803	567
WS-1	70	357	70	357	70	357	70	357	70	357
SNG-1		109		93						
AGT Interruptible	176		7		0		0		0	
AGT Storage Return	0	180		206		206		206		206
LNG from storage		120		120		120		120		120
DOMAC LNG	210	225	210	225	210	225	210	225	210	225
Bay State LNG		263		263		529		590		641
Optional Bay St. LNG		87		0						
Spot LNG		155								
Propane from storage		37		37		37		37		37
Firm propane purchases		125		125		125		125		125
Optional Propane		19		19						
Spot propane		100		89		0		0		0
TOTAL	2,356	4,069	2,545	4,141	2,983	4,206	2,983	4,267	2,983	4,318

Dispatch assumes 1) LNG and underground storage are filled to capacity in the non-heating season.
2) Fall River attempts to take full volumes under firm contracts. Thereafter, Fall River will send out supplementals as required while attempting to minimize costs.
3) Propane volumes in storage will be used during the heating season and will be replaced as used.
4) After the 1986-87 Heating Season Fall River will be able to reduce its firm Bay State LNG quantities to balance load.
5) Fall River is required to remove 75% of its storage gas in any contract year. Therefore, storage return resources must be at least 75% of the Company's storage capacity. Additional resources are dispatched on a cost basis.
6) AGT F-4 volumes are 100% take-or-pay.
7) Fall River's WS-1 contract is extended for at least two years under current terms.

its firm customers on a peak day. Table 6 illustrates the Company's projected peak day sendout capability and requirements for each year of the forecast.

Fall River's resources exceed requirements by about 10-15 percent over the forecast period. Even if the Full F-4 MDQ is delayed, the Company would have sufficient resources to meet peak day requirements. Therefore, the Council finds that Fall River's peak day resources and sendout facilities are sufficient to meet firm peak day requirements.

Table 6

Fall River Gas Company
Peak Day Resources and Requirements

RESOURCES	1985-86	1986-87	1987-88	1988-89	1989-90
Algonquin					
F-1	14.6	14.6	14.6	14.6	14.6
F-4	1.7	3.8	3.8	3.8	3.8
WS-1	7.1	7.1	7.1	7.1	7.1
SNG-1[1]					
STB-1[2]	1.8	1.8	1.8	1.8	1.8
Supplementals					
LNG	20.0	20.0	20.0	20.0	20.0
Propane	12.0	12.0	12.0	12.0	12.0
TOTAL RESOURCES	57.2	59.3	59.3	59.3	59.3
REQUIREMENTS	51.1	52.0	52.7	53.5	54.1

1. SNG-1 MDQs vary from week to week. See Table 3, supra

2. The daily storage demand is 2.0 MMcf. The difference between the daily storage quantity and the firm deliverable portion represents fuel charges.

Source: Forecast, Table G-23

C. Cold Snap

In its previous decision, the Siting Council found that Fall River had clearly adequate resources to meet the requirements of a cold snap, based on the Company's standard of a series of peak days. The Siting Council went on to note that the Company's standard was indeed overly stringent, and ordered the Company to develop and present a more realistic cold snap standard in its next filing.

In response to the Siting Council's condition, Fall River has adopted a cold snap standard based on a 20-day record period in 1980-81. The average daily requirement under the new cold snap standard is approximately 83 percent of that under the Companys' former standard, based on peak day. The Siting Council commends the Company's new cold snap standard.

Approximately two-thirds of Fall River's average daily requirement during a cold snap is met by pipeline. The cold snap analysis then assumes operation of one LNG vaporizer (the Company has two), which can produce another one-quarter of the Company's average daily requirement. Under that rate of use, the Company's LNG storage capability is 15 days with no refilling, 29 days with the Company's two trailers hauling product from DOMAC, or 43 days with one trailer hauling from DOMAC and one from Bay State in Easton (or both from Bay State). The balance of Fall River's cold snap requirement, ranging from 2.6 MMcf per day in 1986-87 to 6.4 MMcf per day in 1989-90,[11] can be met by propane. The Company has a 37 MMcf storage capability for propane and owns three LPG transport tankers, which together can deliver 9 MMcf during a normal shift.

The Siting Council finds that the Company continues to have adequate resources to meet a cold snap, extending out over the five-year forecast period.

VI. IMPACT OF ORDER IN DOCKET NO. 85-64

The Siting Council's Order in Docket No. 85-64, along with new Administrative Bulletin 86-1 implementing that order, institute some changes in the filing requirements to be met by Massachusetts gas companies in future filings, beginning in 1986. Those changes which are most likely to affect the preparation of Fall River's next forecast filing are briefly outlined below.

A. Forecast Accuracy

The Siting Council is instituting a requirement that each gas company report on the accuracy of its past forecasts, vis a vis actual

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[11]The difference reflects the loss of 2.0 MMcf of SNG, as well as a 1.8 MMcf increase in the daily requirement reflecting sendout growth, between 1986-87 and 1989-90.

normalized sendout for the same years. The historical data should be provided in future filings using new Table FA (to be found in Administrative Bulletin 86-1).

B. Normalization Method

The order in Docket No. 85-64 requires gas companies to describe in detail and justify their approach to normalization of weather. Fall River already presents the actual calculations performed in its normalization. Fall River should include in its next filing a detailed description and discussion of its normalization technique, including its reasons for using this method.

C. Design Year and Peak Day Selection

Administrative Bulletin 86-1 requires the gas companies to provide a rationale for their selection of design criteria. At present, Fall River merely reports in Table DD the methods used to derive design year and peak day standards. In future filings, an explanation of how and why the Company selected the design criteria that it uses must be provided.

D. New Split Year

On the recommendation of many gas companies, the Siting Council has determined that the split year used for Siting Council reporting purposes should begin in November along with the heating season rather than in April. This change will affect all gas companies, requiring them to recalculate the sendout for each historical base year in the forecast on a one-time basis, as well as to adjust the seasonal degree day content of the years forming the basis of their normal and design-year criteria. The Siting Council recognizes that this will cause some inconvenience in the preparation of the 1986 forecast, but expects that over the long run the new split year will improve the accuracy and reliability of gas company forecasts.

E. Analysis of Cold-Snap Preparedness

The order in Docket No. 85-64 requires that in their next filing, all large-and medium-sized companies (Fall River is medium-sized) must submit either an analysis of their cold-snap preparedness or an explanation of why such an analysis is unnecessary to demonstrate that they will be able to meet their firm sendout obligations through a protracted period of design or near-design weather. These explanations should discuss a company's supply mix, inventory turnover practices, lead time for attaining supplemental supplies, and historical experience of equipment malfunctions, as well as the company's experience in actual historical cold periods. Should Fall River be able to demonstrate satisfactorily through this explanation that its inventories and other supply capabilities are such that cold snaps do not pose a threat to its ability to meet firm sendout obligations, it may be excused from preparing such cold-snap analyses in the future, unless the Company's supply mixes, inventory turnover practices, equipment performance, or lead times for acquiring supplies change.

F. Cost Studies

Also in Docket No. 85-64, the Siting Council found it appropriate to begin to focus on that portion of the Siting Council's mandate that requires it to ensure for an energy supply for the Commonwealth "at the lowest possible cost." Mass. Gen. Laws c. 164, sec. 69H. While the Siting Council recognizes there may be a trade-off between cost and reliability, the Siting Council seeks to examine the relative cost of the various supply configurations a company could use to meet its needs, since supplies of similar reliability may have different costs.

In this context, the Siting Council finds that in every forecast filing that indicates the addition of a long-term firm gas supply contract is proposed within the forecast period, companies are to perform an internal study comparing the costs of a reasonable range of practical supply alternatives. This requirement is intended to cover instance when the following types of contractual arrangements are proposed: (1) changes in, amendments to or new firm pipeline supply contracts; (2) changes in, amendments to or new firm gas storage contracts and for firm transportation of storage gas; (3) firm supplies of gas from a producer under a contract covering a two-year period or longer, along with related transportation arrangements; (4) any arrangement for supplemental fuel for which the supply is intended for use in a period longer than a single heating year, except for arrangements in which the company can adjust the volumes for the following heating season and and when the supplies are intended primarily for system operation.

The Siting Council expects companies to prepare such analyses as part of their routine planning efforts when considering major new supply options. However, the Siting Council does not prescribe a particular methodology that companies must use in these cost studies. Also, if Fall River is already performing such studies, the Siting Council does not require the Company to conduct other ones specifically to meet this requirement. Finally, the Siting Council does not require the submission of such cost studies as part of each forecast or forecast-supplement filing; however, Fall River may be required to make individual studies available to the Siting Council at its request in cases where the Siting Council or its Staff believes the results of such studies are needed to develop a complete review of the Company's supply plan.

VII. Order

The Siting Council APPROVES The Fourth Supplement to the Second Long-Range Forecast of Fall River Gas Company's natural gas requirements and resources subject to the following CONDITIONS which are to be met in the next Long-Range Forecast to be filed on November 1, 1986:

1. That Fall River present in its next forecast a report on progress to date concerning documentation of residential use factor levels, and how such efforts fit into a long term approach to data development supporting residential use factor projections. The report should build on the results of the Company's appliance survey, and clarify what

additional data development efforts are planned, including as applicable efforts addressing average use per appliance and factors that influence appliance ownership and usage.

2. That Fall River commence a program to improve data and documentation regarding the Company's sendout forecasts for the commercial and industrial classes. The program must include a standardized survey or such other reviewable approach as the Company may propose to assess its customer make-up and usage patterns, and identify related trends.

3. That Fall River shall include in its next filing an update on its contingency plan for LNG, and report on: the status of the Distrigas and DOMAC federal government applications; the impact of Order No. 380 on DOMAC's ability to supply Bay State with LNG and the resultant capability of Bay State to supply Fall River with LNG; the status of any negotiations with Bay State, and as appropriate with DOMAC, relating to reductions in Fall River's Firm LNG supplies; and identification of other potential suppliers of LNG, and possible terms of delivery.

4. That Fall River satisfy the requirements outlined in the Siting Council's Order on the Standards and Procedures for Reviewing Sendout Forecasts and Supply Plans of Massachusetts, as outlined above in Section VI.

5. That Fall River shall provide in its next filing a description of how it has been evaluating the impact that conservation could have on its system supplies. This description shall consider the residential, commercial, and industrial sectors separately.

Susan F. Tierney

Susan F. Tierney
Hearing Officer

September 25, 1986

Approved unanimously by the Energy Facilities Siting Council on September 25, 1986 by those members and designees present and voting; Sarah Wald (for Paula W. Gold, Secretary of consumer Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Joellen D'Esti (for Joseph D. Alviani, Secretary of Economic Affairs); Joseph Joyce (Public Labor Member).

Sharon M. Pollard

Sharon M. Pollard
Chairperson

September 29, 1986
Date

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Cambridge Electric Light, Canal Electric, and Commonwealth Electric Companies for Approval of the 1986 Supplement to the Second Long-Range Forecast of Electric Power Requirements and Resources	)	EFSC No. 86-4

FINAL DECISION

Robert D. Shapiro
Hearing Officer

On the Decision:

John C. Dalton

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The Energy Facilities Siting Council ("Siting Council") hereby APPROVES, subject to Conditions, the Petition of Cambridge Electric Light, Canal Electric, and Commonwealth Electric Companies for Approval of the 1986 Supplement to the Second Long-Range Forecast of Electric Power Needs and Requirements ("Forecast").

I. INTRODUCTION AND HISTORY OF THE PROCEEDINGS

A. Description of the Companies

The Cambridge Electric Light Company ("Cambridge"), the Canal Electric Company ("Canal") and the Commonwealth Electric Company ("Commonwealth") are subsidiaries of the Commonwealth Energy System ("COM/Electric", "the Companies" or "the System").

Cambridge produces, sells and distributes electricity to approximately 40,000 retail customers in the City of Cambridge, and sells power for resale to the Town of Belmont. In addition, Cambridge sells steam from its electric generating plants to an affiliated company, COM/Energy Steam Company. Cambridge had retail sales in 1985 of approximately 1,016,570 megawatt-hours ("MWH"), with a summer peak demand (excluding Belmont) of 216 megawatts ("MW") (Forecast, Tables E-8, E-11).

Commonwealth produces, sells, and distributes electricity to retail customers in forty communities in Southern Massachusetts, including the greater Plymouth and New Bedford areas, Cape Cod, and Martha's Vineyard. Year-round population is approximately 475,000 with summer totals being considerably higher. In 1985, Commonwealth had retail sales of 2,084,010 MWH, with a winter peak demand of 564 MW (Forecast, Tables E-8, E-11).

Together, Cambridge and Commonwealth had retail sales in 1985 of 3,100,580 MWH and a coincident summer peak load (excluding Belmont) of 751 MW. Commonwealth's load comprised 73 percent of the System's retail sales and approximately 72 percent of the coincident summer peak demand in 1985 (Forecast, Tables E-8, E-11).

Canal generates electricity at two facilities located along the Cape Cod Canal in Sandwich, Massachusetts. Canal Unit No. 1, rated at 568 MW, is an oil-burning base load unit; Canal Unit No. 2, rated at 584 MW, is an oil-burning cycling unit. Canal sells the output of Unit No. 1 to five utilities, including Cambridge and Commonwealth which purchase twenty-five percent of the unit's output and generating capacity. Ownership of Unit No. 2 is evenly divided between Canal and Montaup Electric Company, an unaffiliated company. Canal's other major assets are the System's entitlements in Seabrook Units 1 and 2, amounting to 81 MW or 3.52 percent of each unit. Canal has no retail sales (Forecast, Table E-8).

Each of the System's retail companies produces its own forecast of total energy demand and coincident peak demand. Supply information, filed with the Siting Council by all three companies, is reviewed for the COM/Electric System as a whole, consistent with the System's treatment by the New England Power Pool. Demand and supply information for the three companies is filed in a single document at the Siting Council.

As in past reviews of COM/Electric's supply plan, the Siting Council analyzes the adequacy, cost, and diversity of the Cambridge, Canal, and Commonwealth supply plans on a combined basis since the Companies operate their facilities and plan as a single System and are treated as a single entity by the New England Power Pool ("NEPOOL"). In Re COM/Electric, 12 DOMSC 39, 72 (1985).

In its review of COM/Electric's previous filing, the Siting Council approved the Companies' demand forecast without conditions and rejected their supply plan. The Siting Council ordered the Companies to present in their next forecast: (1) a supply plan demonstrating sufficient capacity to meet their projected peak loads and reserve requirements; (2) a sensitivity analysis of the magnitude and timing of their planned additions and capacity needs under a reasonable set of contingencies; (3) a forecast of the potential of cogeneration to meet the Companies' capacity and energy needs; and (4) a cost-benefit analysis of all of their projected supply additions and conservation programs.

B. History of the Proceedings

On December 31, 1985, the Companies filed their Forecast with the Siting Council. The Companies provided notice of the proceeding by publication and posting in accordance with the directions of the Hearing Officer.[1]

On January 31, 1986, Harvard College ("Harvard") filed a petition to intervene in the proceeding. On April 28, 1986, Harvard withdrew its petition to intervene.

The Siting Council staff conducted a pre-hearing conference on April 17, 1986. In addition, on May 12, 1986, the Siting Council staff met COM/Electric representatives for a technical session to discuss information requests. The Siting Council staff conducted an evidentiary hearing on October 9, 1986. The Company presented three witnesses at the hearing: Donald J. LeBlanc, Director of System Planning; B. L. Hunt, Supervisor of Facilities Planning; and Robert L. Fratto, Manager of Demand Planning and Forecasting. The Hearing Officer entered fifty-nine exhibits in the record, largely composed of the Companies' responses to information and record requests.

[1]Pursuant to an agreement between the Companies and the Siting Council staff, COM/Electric was not required to file a standard demand forecast as part of its 1986 Forecast. Instead, the 1986 Forecast comprised the Companies' supply plan and selected "summary" tables requested by the Siting Council staff and filed by the Companies on April 17, 1986.

II. THE DEMAND FORECAST

The Companies' demand forecast is based on the same methodology as presented in the Companies' previous forecast. Combined First and Second Supplements to the Second Long-Range Forecast, EFSC Docket 84-4. In issuing an unconditional approval of that demand forecast, the Siting Council noted that Cambridge was "continuing to improve its demand forecasting methodology," 12 DOMSC 39, 50 (1985), and that "Commonwealth has developed its methodology to the point where it can shift its focus from major development efforts to model maintenance and refinement." 12 DOMSC 39, 71 (1985).

Table 1 provides a summary of the COM/Electric base case demand forecast used by the Companies in their supply planning analyses.[2] COM/Electric forecasts an average annual compound growth in Cambridge's and Commonwealth's coincident summer and winter peaks of 2.1 and 1.9 percent, respectively, over the 1986-1995 forecast period. Over the same period, the System forecasts that its "capability responsibility," the sum of forecasted peak loads and the reserve capacity required by NEPOOL, will grow at a 2.3 percent compounded rate per year.[3] The Companies forecast that their total energy requirements will grow at a 1.9 percent average annual rate, resulting in a decrease in the System's total load factor from 64.0 percent to 63.2 percent.

Since the Siting Council unconditionally approved the Companies' demand forecast in its last decision, but rejected its supply plan, the

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[2] The Companies also prepare a low and high forecast based on an assessment of the probabilities associated with demographic and economic variables and weather conditions (Forecast at 5). See Section III.C. for a more detailed discussion of how the Companies' prepare their forecast scenarios.

[3] The higher forecasted growth for the System's capability responsibility reflects the Companies' assumption that required reserves will grow from 21 percent of total system load in 1985 to 25 percent in 1995 (Forecast at 33).

TABLE 1

COM/Electric System

Demand Forecast Summary

	Annual Energy (1000's of MWH) 1986	1995	Average Annual Compound Growth Rate 1986-1995
Residential	1,480	1,734	1.8%
Commercial	1,836	2,191	2.0%
Industrial	532	647	2.2%
Total Energy Requirements	4,196	4,969	1.9%
	Peak Load (MW)		
Cambridge			
Summer	228	261	1.5%
Winter	188	216	1.6%
Commonwealth			
Summer	539	659	2.3%
Winter	568	691	2.2%
Total System			
Summer	743	897	2.1%
Winter	749	888	1.9%
Capability Responsibility	906	1110	2.3%

Source: Forecast, Tables E-8 & E-11.

Note: Total System load is coincident system peak thus Cambridge and Commonwealth loads do not add to total system peak.

Note: Total System loads as presented in Figure 25 in the Forecast do not correspond with Table E-11 submitted by the Companies. The System loads presented in Figure 25 in the Forecast and in Table 2 in this Decision include sales to the Belmont Municipal Light Department ("Belmont"), whereas the loads for Table E-11 do not include sales to Belmont (Tr. at 112).

Siting Council accepts the new forecast based on the previously approved methodology and focuses its review on COM/Electric's supply plan.

III. 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 consistently reviews three dimensions of a utility's supply plan: cost, adequacy, and diversity. 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. 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. COM/Electric, 12 DOMSC 39, 72 (1985). Ultimately, the Siting Council evaluates whether a supply plan minimizes the long-run cost of power subject to trade-offs with adequacy, diversity, and the environmental impacts of construction and operation of new facilities. The Siting Council's evaluation of the long-run cost of the supply plan generally focuses on a company's supply planning methodology. Finally, the Siting Council reviews utilities' demand management programs, cogeneration projects and small power production efforts on the same basis as the consideration of new conventional bulk power facilities when analyzing the adequacy, diversity, and cost of a supply plan. In Re COM/Electric, 12 DOMSC 39, 72 (1985); In Re EUA, 11 DOMSC 61, 96 (1984).

Recently, the Siting Council has started reviewing in greater detail the supply planning processes utilized by utilities, with the objective of assessing the extent to which these processes facilitate the development and implementation of long-range supply plans that are least-cost, adequate, and diversified. Recognizing that supply planning is a dynamic process undertaken within a technological, economic, and regulatory environment that evolves over time, the Siting Council requires a utility's supply plan to identify, evaluate, and choose from a variety of supply options based on reasonable, appropriate, and documented criteria. A company's development of such criteria and its demonstration that it has consistently and systematically applied them in analyses supporting decisions would instill confidence 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, if not unreasonable, for a company to identify with exactitude all the power supply resources it plans to rely upon in the latter years of its ten-year forecast. In Re Fitchburg Gas Electric, 13 DOMSC 85, 102, (1985).

While the Siting Council has broadly defined adequacy as the ability of a utility to provide sufficient capacity throughout its forecast period, the changing character of the electricity marketplace and the risks associated with projecting both demand and the availability of power supplies requires the Siting Council to apply different standards of review for determining adequacy in the short- and long-run.

In order to establish adequacy in the short-run,[4] a company must demonstrate that it has an identified and a secure set of power supplies to meet its peak loads and reserve requirements under a reasonable ranges of contingencies. 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 an identified and a secure set of supplies under a reasonable range of contingencies in the short-run, the company must then demonstrate that it operates pursuant to a specific action plan that guides it in drawing upon alternative

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[4]The Siting Council's definition of short run will be determined on a company-by-company basis and will vary according to the shortest-lead-time resources(s) a company has under its control to put into service to meet the company's need for new capacity.

supplies should certain preferred projects not develop within the time, cost and reliability parameters needed by the company to meet its capability responsibility in a least-cost, reliable manner.

In order 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 and allow the company to make appropriate decisions regarding those supply options in sufficient time to ensure adequate 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 generating 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 its supplies in a creative and dynamic manner.

B. Previous Supply Plan Reviews

The Siting Council rejected COM/Electric's previous supply plan for failing to demonstrate an adequate supply of power and for failing to comply with two conditions issued in the Siting Council's earlier decision. 12 DOMSC 39, 78 (1985).

To ensure that its adequacy standards were met, the Siting Council ordered COM/Electric to present in this filing a supply plan that provides "sufficient capacity to cover projected peak demand and reserve requirements for all forecast years." 12 DOMSC 39, 79 (1985). The Companies have minimally complied with this condition in their 1986 Forecast, as discussed in Sections III.E.1 and III.E.2.

Furthermore, the Siting Council informed the Companies that all future supply plans or applications to construct new generation or transmission facilities had to contain an acceptable sensitivity analysis. Toward this goal, the Siting Council ordered COM/Electric "to present in its next filing a complete sensitivity analysis of the magnitude and timing of its planned additions and capacity needs under a reasonable set of contingencies." 12 DOMSC 39, 81 (1985). The Companies' 1986 Forecast has minimally complied with this condition, as discussed in Sections III.C., III.E.1, III.E.2, and III.E.3.

Because the Companies had forecast capacity short-falls and had failed to actively promote cogeneration, the Siting Council also ordered the Companies in this filing to forecast the potential for cogeneration to supply the System with capacity and energy requirements for peak reduction due to customer self-generation. 12 DOMSC 39, 83 (1985). The Companies' 1986 Forecast did not comply with all the requirements of this condition, as discussed in Section III.E.2.c.

To ensure that the Companies continued to develop their analytical capabilities to perform cost/benefit analyses of their projected supply additions, the Siting Council also ordered the System to continue its efforts to perform cost-benefit analyses of all projected supply additions and conservation programs. 12 DOMSC 39, 92 (1985). The Companies did not fully comply with this condition in their 1986 Forecast, as discussed in Section III.E.4.

C. Supply Planning Methodology

COM/Electric's current supply plan is developed through a methodology which uses a seven-step process: (1) prepare bandwidth energy and demand forecasts; (2) collect data (e.g., fuel price forecast); (3) develop a range of reasonable supply alternatives; (4) select a "base case" and a mix of alternatives; (5) analyze and evaluate the various supply strategy alternatives through the use of the Load Management Strategy Testing Model; (6) evaluate the alternatives on the basis of the expected value of different fuel price and demand scenarios; and (7) choose the alternative which offers the lowest expected cost of all alternatives (Forecast at 3).

The Companies used an expansion planning model to evaluate the adequacy of COM/Electric's available capacity to meet the System's capability responsibility and hence to forecast incremental capacity costs. If insufficient capacity were available in any time period, then the model would add capacity so that the Companies meet their capability responsibility (Forecast at 10).

The Companies used the Load Management Strategy Testing Model ("LMSTM") to calculate system production costs (i.e., energy costs and variable operation and maintenance expenses of each generating facility). LMSTM has four different submodels -- demand, supply, rate and financial -- "which work together to represent a utility system and produce detailed simulations of alternative strategies" (Forecast at 45). The demand submodel contains the System load shapes and demand forecasts generated by the Companies' Hourly Load Value Model (Forecast at 6). The supply submodel has a production costing simulator which calculates "system production costs by simulating the economic dispatching of the generating units in a company's capacity mix" (Forecast at 45). The Companies use the Gilbert Associates' Fixed Charge Program in place of LMSTM's financial and rates submodels (Tr. at 71, 75).

LMSTM is not an optimization model; the model does not select the resource which offers the lowest total net present value of system costs (Tr. at 64), nor does it determine the year(s) in which generating units are added into a company's supply mix (Tr. at 65). The modeler must specify both the type of generating unit and the year it is added. Given that LMSTM does not have an optimization routine for adding in different generation alternatives, a user must rerun, or iterate, the model manually to develop system cost estimates for different generation alternatives and identify those that offer the lowest total system costs (Tr. at 105).

The Companies used LMSTM in this iterative fashion. To test the sensitivity of their generation expansion plan to the uncertainty associated with supply options, the Companies used contingency analysis in which they evaluated the impact of a specific contingency on the total net present value of system costs. The Companies provided evidence that they evaluated thirteen supply plan contingencies, ranging from lower availabilities for Seabrook 1 or Canal 2, to cancellation of the SEMASS or Hydro Quebec Phase 2 projects.

Each contingency was also subjected to a sensitivity analysis in which the companies evaluated three fuel-price/demand growth scenarios in order to determine the expected cost of the contingency. This "scenario analysis" was conducted to capture the sensitivity of the Companies' demand forecast and supply planning requirements to the uncertainty associated with key economic variables: a base case, which was assumed to have a probability of 0.8; a high fuel-price/low-demand growth scenario with a probability of 0.1; and a low fuel-price/high-demand growth scenario with a probability of 0.1. The three different fuel-price/demand-growth scenarios were used based on forecasts and associated probabilities developed by Data Resources, Inc. (Exhibit HO-5).

D. Supply Plan Results

The Companies' use of their planning approach yielded the "supply plan" presented in the 1986 Forecast. They described it as "an optimistic scenario encompassing the full penetration of demand management and alternative resource targets, Hydro Quebec Phase II, and the construction of Pt. Lepreau 2" (Exhibit HO-GI-5, emphasis in original). Table 2 identifies the elements of this supply plan. COM/Electric further describes this supply plan "as an expansion scenario for the future that integrates the most economic elements of demand management, alternative energy resources, existing facilities and new generation, to create a balanced supply plan" (Forecast at 32).

TABLE 2

COM/Electric Long Range Supply Plan
(MW)

Year	Existing Facilities	Seabrook	Hydro Quebec Phase 2	Pt. Lepreau Unit 1	SEMASS	Black-stone Station	Pt. Lepreau Phase 2	Qualified Facilities	Pool Purchases	Gas Turbines	Total Capacity
1985	835			25				10	10		880
1986	835			25				10	44		914
1987	835	41		25	40			20	0		961
1988	835	41		25	40	-22		20	22		961
1989	835	41		25	40	-22		30	32		980
1990	835	41	58	25	40	-22		30			1007
1991	835	41	58	25	40	-22		40			1017
1992	835	41	58		40	-22	50	40			1042
1993	835	41	58		40	-22	50	50			1052
1994	835	41	58		40	-22	50	50			1052
1995	835	41	58		40	-22	50	60			1062
1996	835	41	58		40	-22	50	60		75	1137
1997	835	41	58		40	-22	50	60		75	1137
1998	835	41	58		40	-22	50	60		75	1137
1999	835	41	58		40	-22	50	60		75	1137
2000	835	41	58		40	-22	50	60		75	1137
2001	835	41			40	-22	50	60		159	1154
2002	835	41			40	-22	50	60		159	1154
2003	835	41			40	-22	50	60		225	1229
2004	835	41			40	-22	50	60		225	1229
2005	835	41			40	-22	50	60		225	1229
2006	835	41			40	-22	50	60		225	1229
2007	835	41			40	-22	50	60		225	1229
2008	835	41			40	-22	50	60		308	1304
2009	835	41			40	-22	50	60		300	1304

TABLE 2
(continued)

Year	Total Capacity	Demand	Demand Mngt.	Reserve Requirements	Total Demand	(+/-)	Reserve Margin
1985	880	725	0	21%	880	0	21.0%
1986	914	762	7	21%	914	0	21.0%
1987	961	787	11	21%	939	22	23.8%
1988	961	810	16	21%	961	0	21.0%
1989	980	831	21	21%	980	0	21.0%
1990	1007	848	28	22%	1000	6	22.7%
1991	1017	862	36	23%	1016	1	23.1%
1992	1042	877	45	24%	1032	10	25.2%
1993	1052	892	57	25%	1044	8	25.9%
1994	1052	905	71	25%	1043	9	26.1%
1995	1062	917	75	25%	1053	9	26.1%
1996	1137	930	80	25%	1063	74	33.7%
1997	1137	941	82	25%	1074	63	32.3%
1998	1137	952	85	25%	1084	53	31.1%
1999	1137	964	87	25%	1096	40	29.6%
2000	1137	979	89	25%	1113	24	27.7%
2001	1154	994	93	25%	1126	27	28.0%
2002	1154	1009	97	25%	1140	14	26.5%
2003	1229	1024	100	25%	1155	74	33.0%
2004	1229	1039	103	25%	1170	59	31.3%
2005	1229	1055	107	25%	1185	44	29.6%
2006	1229	1071	110	25%	1201	27	27.3%
2007	1229	1087	113	25%	1218	11	26.1%
2008	1304	1103	116	25%	1234	70	32.1%
2009	1304	1120	119	25%	1251	52	30.2%

Total Demand = (Peak Demand - Demand Management) * (1 + Reserve Requirement)

Reserve Margin = Total Capacity/(Peak Demand - Demand Management)

Source: Forecast, Figure 25.

In addition to existing resources, this supply plan includes: 41 MW from Seabrook 1 assumed to be available January 1, 1987;[5] 58 MW from the Hydro-Quebec Phase 2 Firm Energy Contract from 1990 through 2000; 40 MW from the SEMASS refuse-recovery plant assumed to be available in 1987; 50 MW from Pt. Lepreau (Units 1 or 2) in 1992, to coincide with the loss of the contract for 25 MW of Pt. Lepreau Unit 1; an additional 60 MW from yet to be identified Qualifying Facilities ("QFs"), assumed to be available by 1995; capacity purchases from other NEPOOL participants in 1986, 1988, and 1989; 75 MW from demand management by 1995; and 225 MW from the installation of gas turbines in years that fall outside of the Siting Council's ten-year forecast horizon. The Companies' supply plan shows no deficiencies throughout the forecast period (Forecast at 33).

In addition to identifying the specific components of their preferred supply strategy, the Companies indicate than an essential feature of their plan is its inclusion of the results of their contingency/scenario analyses and alternate supply plans on the System's projection of total incremental capital and production costs.[6]

The results of these contingency/scenario analyses are summarized in Table 3. Each line in the table indicates the key assumptions and results of a single run of the LMSTM model. In the table, the first column identifies the contingency or scenario analyzed. For example, the fourth scenario -- the first scenario after the various base case

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[5] In the Forecast the Companies assumed a starting date of January 1, 1987, as opposed to the official commercial operation date of October 31, 1986, because of programming restrictions in the Companies' supply planning model, LMSTM, which require that "new generation come on line at the beginning of the calendar year" (Exhibit HO-CSS-4a).

[6] In the Forecast the Companies state that "COM/Electric is committed to meeting the challenges of the future by developing long range plans which will be flexible enough to meet a range of future possibilities. The ultimate goal is to choose a portfolio of diversified options that will meet our customer's future needs reliably and at the lowest reasonable cost" (Forecast at 1).

TABLE 3

COM/Electric System
Summary of Sensitivity Scenarios

Scenario/Contingency	Capacity Met By:	Difference in Expected Cost Relative to Base Case Gas Turbine Plan (1000's of 1985 $)
Base Case *	Gas Turbine	$0
Base Case	Combined Cycle	$131,435
Base Case	Coal Unit	$363,909
Demand Management with Load Shifting	Gas Turbine	($51,843)
Demand Management with Conservation	Gas Turbine	($188,880)
Demand Management with Peak Clipping	Gas Turbine	($156,385)
Demand Management with Valley Filling	Gas Turbine	$19,954
Demand Management with Load Shifting	Combined Cycle	$12,200
Demand Management with Conservation	Combined Cycle	($119,176)
Demand Management with Peak Clipping	Combined Cycle	($88,075)
Demand Management with Valley Filling	Combined Cycle	$133,430
SEMASS Cancelled	Gas Turbine	$100,524
SEMASS Cancelled	Combined Cycle	$252,449
Canal Unit 1 Life Extension	Gas Turbine	$73,327
Canal Unit 1 Life Extension	Combined Cycle	$226,529
Canal Unit 1 Life Extension	Coal Unit	$568,540
Canal Unit 2 10% Increase in FOR	Gas Turbine	$25,745
Canal Unit 2 10% Increase in FOR	Combined Cycle	$150,662
Canal Unit 2 10% Increase in FOR	Coal Unit	$383,656
Canal Unit 2 20% Increase in FOR	Gas Turbine	$57,282
Canal Unit 2 20% Increase in FOR	Combined Cycle	$174,403
Canal Unit 2 20% Increase in FOR	Coal Unit	$456,707
Cannon Street Life Extension	Gas Turbine	$28,878
Cannon Street Life Extension	Combined Cycle	$186,419
Hydro Quebec Phase 2 Cancelled	Gas Turbine	$11,105
Hydro Quebec Phase 2 Cancelled	Combined Cycle	$155,680
Pt. Lepreau - 50 MW Capacity Purchase	Gas Turbine	($99,111)
Pt. Lepreau - 50 MW Capacity Purchase	Combined Cycle	$17,497
Seabrook 1 - Decrease in Capacity Factor	Gas Turbine	$10,397
Seabrook 1 - Decrease in Capacity Factor	Combined Cycle	$141,004
Fuel Availability - No Interruptible Gas	Gas Turbine	$52,337
Fuel Availability - No Interruptible Gas	Combined Cycle	$189,588

Sources: Forecast at 14-31.

* Base Case assumes that: Seabrook 1 will come on-line January 1987; Hydro-Quebec Phase 1 will be available starting in 1987; 40 MW from SEMASS will be available starting in 1987, Blackstone Station will be retired in 1988; the target of 130 MW from alternate energy resources will be reached by 1995 and gas turbine capacity will be available from NEPOOL participants during the 1980's; and the NEPOOL Reserve margin will increase to 25 percent by 1993.

scenarios -- assumes the Companies would add demand management programs that would produce a shifting of load relative to the base-case demand forecast. In the twelfth scenario, the Companies' base case forecast and supply plan would be altered only by the exclusion of the SEMASS project. The second column in Table 3 identifies the generation technology which was assumed in each analysis to meet increases in the Companies' capability responsibility in future years. The third column identifies the difference in the net present value of total system costs relative to the the base case supply plan with gas turbines. All scenarios include the base-case assumptions changed only by the actual contingency or scenario evaluated (e.g., the Pt. Lepreau 50 MW capacity purchase scenario evaluates the value to COM/Electric of a 50 MW capacity purchase from Pt. Lepreau under base case assumptions).

According to the Companies, the projections presented in the third column indicate "the maximum amount which can be spent on a particular program before it becomes uneconomic relative to the alternative of installing new generation" (Forecast at 2). The Companies provided no information on the cost of these programs so that the costs and benefits (as reflected by the change in incremental production and capital costs) could be directly compared. See Section III.E.4.

According to the analysis performed by the Companies, gas turbines offered the lowest total system cost for every contingency evaluated and under each fuel price scenario (Exhibit HO-GI-3a). (Forecast at 32). This supply plan shows the addition of new gas turbines in 1996, 2001, 2003, and 2008, in order for COM/Electric to meet its capability responsibility requirements. See Table 2.

COM/Electric attributes the favorable economics of gas turbines relative to combined-cycle and base-load coal plants to a number of factors. The Companies assert that their projected generating mix provides sufficient base and intermediate load resources such that the Companies need additional capacity, not additional energy (Exhibit HO-GI-3a). The Companies state that gas turbines, as compared to base-load generating plants, are a relatively inexpensive means of installing capacity; have relatively short construction lead times; can be installed when needed; are available in relatively small sizes (e.g., 75 MW) and make it easier for the System to absorb the increased capacity; thereby lessen the risk of surplus capacity; and thus reduce financing costs by requiring less short- and long-term borrowing (Exhibit HO-GI-3a). COM/Electric asserts that gas turbines also offer the System a large degree of flexibility, since, should the Companies need additional energy after the gas turbines have been installed, a heat-recovery boiler and steam turbine could be retrofitted to the gas turbine making it a combined-cycle unit (Forecast at 32).

Still, the Companies note that the siting of gas turbines would require an exemption from the federal Fuel Use Act of 1978, which prohibits the construction of new oil- and gas-fired power plants. The Companies believe that they can secure exemptions since the act provides a ten-year exemption for plants capable of converting to synthetic fuels, e.g., coal gasification[7] (Exhibit HO-CSS-8b).

E. Analysis of the Supply Plan

1. Adequacy of Supply in the Short-Run

In accordance with the Siting Council's previously articulated standard of review, Section III.A., supra., COM/Electric's supply plan is evaluated in terms of its ability to meet energy requirements in both the short-run and long-run.

A company's short-run forecast period is defined as the time required to implement the first resource under a company's direct control to meet the projected need for new capacity. The short-run

[7] The exemption provision provides that: "[c]ontracts based on the anticipated successful demonstration of a development program and/or the anticipated economic feasibility of a synthetic-fuels facility will generally be sufficient to meet the binding contract requirements of this exemption" (Exhibit HO-CSS-8b).

forecast period varies for different companies and different supply scenarios. See Section III.A. For purposes of this analysis, the Siting Council estimates COM/Electric's short-run forecast period to be one to five years. The Siting Council has chosen a one-to-five year period because gas turbines, the Companies' preferred option for obtaining additional capacity, require up to five years to place in service (Exhibits HO-CSS-15; HO-19).[8]

The Companies have set forth eight supply sources -- (1) Seabrook 1; (2) SEMASS; (3) NEPOOL capacity purchases; (4) Hydro Quebec Phase 2; (5) Pt. Lepreau; (6) new gas turbines; (7) small power production; and (8) demand management -- as the new elements of its supply plan to meet forecasted demand. In order to determine whether the Companies have adequate supply in the short-run, the Siting Council examines the Companies' reliance upon Seabrook 1, the SEMASS project, and NEPOOL capacity purchases.

a. Seabrook 1

COM/Electric is a joint participant in the Seabrook nuclear project. Seabrook Unit 1 was scheduled to begin loading fuel on June 30, 1986 and to begin commercial operation on October 31, 1986. As of the date of the hearing, the fuel had not yet been loaded. When the Companies filed their Forecast in December 1985, they assumed that Seabrook 1 would be on-line on January 1, 1987 (Exhibit HO-CSS-4a). The Companies now assume that for budget and planning purposes Seabrook 1 will not be available until November 1, 1987 (Tr. at 33).

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[8] In other cases, including other reviews of COM/Electric's filings, 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.

The Siting Council finds that the changing assumptions with regard to in-service dates for Seabrook 1 reflect the continuing uncertainty associated with the timing of that project. The Siting Council, therefore, finds that the delay or loss of Seabrook 1 is a reasonable contingency which the Companies have failed to evaluate in their supply planning analyses.

In response to questioning of the Siting Council staff, the Companies indicated that if Seabrook 1 were delayed they would pursue demand-side programs and contracts with small power producers to help meet their resultant capacity needs and that the remaining capacity requirements would be met through the purchases of replacement capacity from other NEPOOL participants (Tr. at 38-39).

The Companies failed to establish that they will be able to rely on these strategies in the short-run -- in particular the summer of 1987 -- in a sufficient amount to avoid capability responsibility deficiencies during those periods. At the hearing, the Companies indicated that they currently lack sufficient data to develop an accelerated implementation schedule for demand management programs of sufficient magnitude to meet the Companies' near-term capacity deficiency should Seabrook 1 not be available during the summer of 1987 (Tr. at 107). Furthermore, based on the fifteen-month lead time required for the CPC Lowell Cogeneration Corporation (Exhibit HO-SPP-19), additional contracts with cogenerators or small power producers are not likely to be a viable source for meeting the Companies' capacity deficiency in the summer of 1987. Thus, the Companies would have to rely on capacity purchases from other NEPOOL participants to cover their capacity deficiencies should Seabrook 1 be delayed through the summer of 1987, as the Companies now assume.

The Siting Council notes, however, that for the summer of 1987, if Seabrook 1 is not available, an analysis of NEPOOL projections for capacity, load, and reserve requirements for the NEPOOL member utilities indicates that there would be a net surplus in NEPOOL of only 110 MW (Tr. at 59). Relative to a projected load and reserve requirement of 22,227 MW for the summer of 1986, this 110 MW net excess for the pool reflects a relatively tight pool-wide power market that could occur if Seabrook 1 were unavailable in the summer of 1987.

In this case, the record indicates that, in January 1986, Northeast Utilities ("NU") offered up to 156 MW of summer-rated capacity to NEPOOL participants (Exhibit HO-3). However, COM/Electric has failed to establish that it has taken steps to firm up options for NU's capacity or any other capacity offers for the summer of 1987. While the Companies indicate that they are negotiating with NU and other companies that have solicited bids for capacity purchases (Tr. at 17), the Siting Council requires more concrete evidence that utilities will actually be able to contract for excess capacity to meet short-run energy requirements. Accordingly, the Siting Council finds that the Companies have failed to establish that they have an identified and a secure set of power supplies to meet energy requirements in the short-run in the event that Seabrook 1 is lost or delayed.[9]

The Siting Council has previously articulated its standard for determining adequacy of supply in the short-run. See Section III.A. In that the Companies have failed to establish their ability to meet reasonable contingencies in the short-run, COM/Electric must instead demonstrate that it operates pursuant to a specific action plan designed to draw on alternative supplies to meet reasonable contingencies.

However, we recognize that our standard of review for supply planning in the short-run has been set forth for the first time in this case. The Siting Council also notes that it requires a more detailed evidentiary record regarding any action plan of the Company. Accordingly, the Siting Council will refrain from rejecting

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[9] The Companies' failure to establish adequate supply in the short-run is exacerbated in the event that the SEMASS project is delayed past the summer of 1987, a near certain contingency. See Section III.E.1.b. As such, the delay or loss of both Seabrook 1 and the SEMASS project represents a reasonable "double contingency" which has not been addressed by COM/Electric.

COM/Electric's supply plan in this matter. Instead, the Siting Council ORDERS the Companies to produce an acceptable action plan for meeting their capability responsibility in the event that Seabrook 1 is not available in the short-run, particularly in the summer of 1987. The Companies must submit this action plan within sixty days of the issuance of this decision and provide sufficient documentation to establish that the Companies can and will be able to implement this action plan to provide an adequate supply of energy at least cost under a reasonable range of contingencies.

b. SEMASS

COM/Electric has signed a contract with Energy Answers, Inc. for the purchase of the energy and capacity, assumed to be 40 MW, from the SEMASS refuse-to-energy facility at a price based on the Companies' long-run avoided costs (Forecast at 20). In their Forecast, COM/Electric assumes that SEMASS will begin commercial operation in January 1987 (Forecast at 33). However, site preparation at SEMASS only began in early 1986 and the plant has a construction lead time of 30-to-33 months (Exhibit HO-SPP-1). Further, at the time of the hearing, the Companies indicated that they expected the SEMASS project to begin commercial operation in the first quarter of 1988 (Tr. at 9).

The cancellation of the SEMASS project is one of the contingencies evaluated by the Companies. The net impacts on the Companies' supply plan of such a cancellation were to (1) increase total system costs; (2) increase the need for capacity purchases from other NEPOOL participants prior to 1991; and (3) accelerate the generating unit installation schedule after 1990 (Forecast pp. 69-74). With the exception of the concerns mentioned in the previous section regarding short-run capacity needs associated with the possible loss of Seabrook 1 and SEMASS in the summer of 1987, the Siting Council finds that a delay or loss of the SEMASS project, alone, would not threaten the Companies' adequacy of supply in the short-run.

c. NEPOOL Purchases

COM/Electric plans on meeting its NEPOOL capability responsibility in three years of the forecast period -- 1986, 1988 and 1989 -- by purchasing capacity from other NEPOOL members. In support of its plan to make short-term capacity purchases, the Companies assert that "based on the April 1, 1986, NEPOOL CELT Report, ... there will be unit capacity available in New England at least through 1993" (Exhibit HO-CSS-10b). Furthermore, COM/Electric notes that, in the short-term, it could rely upon the NEPOOL capacity market to remedy discrepancies between "system capability and NEPOOL Capability Responsibility due to unforeseen circumstances" (Exhibit HO-CSS-10b).

In its review of COM/Electric's previous supply plan, the Siting Council expressed its concern about the risks of reliance on NEPOOL purchases. The Siting Council notes that the Companies had openly acknowledged the risks of this strategy:

> "...While this option affords maximum flexibility, it is obvious that not all NEPOOL participants can engage in such behavior indefinitely since available capacity in the Pool would soon be exhausted. Further, this is viewed as a limited option since NEPOOL participants that have capacity to sell will offer their higher cost oil-fired generation and retain their nuclear and coal capacity for their own system use." 12 DOMSC 39, 80 (1985).

To reduce the risks associated with reliance on short-term capacity purchases, the Companies are "considering a firm capacity purchase for the period through 1993, with an option for first-right-of-refusal to purchase additional capacity during that period" (Exhibit HO-CSS-10-b). In support of their assertion that sufficient capacity currently is available to meet the needs identified, the Companies provided correspondence and internal memoranda regarding short-term capacity purchases (Exhibit HO-CSS-3). These correspondence and memoranda show that sufficient capacity is available to meet the needs identified by the Companies. Accordingly, the Siting Council finds that the Companies' reliance on purchases from other NEPOOL members does not adversely affect the adequacy of the Companies' resources. The only exception related to this finding has been previously discussed in reference to a contingency wherein the delay of Seabrook 1 through the summer of 1987 could lead to a tight market for excess capacity within NEPOOL, in which COM/Electric might have to act quickly to insure it has access to sufficient competitively priced capacity for 1987 offered by other NEPOOL participants. (See Section III.E.1.a.)

2. Adequacy of Supply in the Long-Run

The Siting Council applies a different adequacy test for the long-run in that new, but as-yet unknown, resource options may arise and offer reliable and cost-effective power to an electric company in later years of its forecast. The long-run adequacy standard requires a company to demonstrate that its supply planning processes instill confidence that the company will identify and fully evaluate a reasonable range of supply options on a continuing basis and will make appropriate decisions and arrangements in sufficient time to ensure adequate power through all forecast years.

The Siting Council has considered the following long-run supply sources as set forth by the Companies.

a. Hydro Quebec Phase 2

COM/Electric is a participant in the Hydro Quebec Phase 2 project. Through a 2000 MW Hydro Quebec/NEPOOL interconnection and under the terms of the Phase 2 firm energy contract, NEPOOL will import seven billion kWH per year from Hydro Quebec from 1990 through 2000 in order to displace high cost generation and to avoid capacity additions in that period. COM/Electric's share of this project represents a capacity value of 58 MW for the Companies (Forecast at 27).

The Companies evaluated the impact of the cancellation of the Phase 2 project. The net effect of this cancellation was to increase total system costs and accelerate the installation schedule for generating units (Forecast at 89-94). Accordingly, the Siting Council finds that the cancellation of Hydro Quebec Phase 2 project would not threaten the adequacy of the Companies' resources in the long-run.

b. Demand Management Programs

The Companies have presented a schedule of annual peak reductions from demand management (See Table 2), but have provided little technical support for how these planned annual peakload reductions were determined. COM/Electric estimates that its total system demand management potential is 75 MW by 1995. COM/Electric states that "this analysis represents a first step in identifying load management potential. It is anticipated that these estimates will be re-evaluated in the near future" (Exhibit HO-DMP-1a).

Table 4 illustrates the Companies' projection of the peak load reduction from demand management for each sector for both Commonwealth and Cambridge projected to be available by 1995. These estimates were developed by first identifying the end uses which made a significant contribution to the summer peak. LMSTM was then used to estimate the reduction attributable to residential programs. The Companies estimated the demand management potential in the commercial class on the basis of information taken from a review of the electricity-conservation literature (Exhibit HO-DMP-2). The peak reduction for the industrial class was limited to one strategy -- interruptible rates -- and was estimated on the basis of the loads of the "known potential interruptible rate customers" (Exhibit HO-DMP-2).

The Companies, however, failed to provide any information on the cost-effectiveness of these demand management capacity increments. Therefore, the Siting Council is unable to determine whether the 75 MW of targeted peak reduction from demand management by 1995 is feasible, let alone consistent with a least-cost supply plan.

In this case, the Companies evaluated generic demand management strategies (e.g., peak clipping) rather than specific demand management programs (e.g., interruptible rates). The Companies stated that they used this strategy "to test the sensitivity of the different new generation strategies (i.e., gas turbine, combined cycle, coal) to the effects of generic load shape changes, not to evaluate the economics

Table 4

COM/Electric System

Load Management Potential
(Summer 1995)

COMMONWEALTH	Estimated 1995 Savings (MW)
Residential	
Uncontrolled Water Heaters	7.0
Water Heater Wrap	0.6
Total Residential	7.6
Commercial	
Lighting	18.1
Office Cooling	0.4
Stores Cooling	1.4
Total Commercial	19.9
Industrial	28.5
TOTAL COMMONWEALTH	56.0
CAMBRIDGE	
Industrial	3.7
Commercial	15.2
TOTAL CAMBRIDGE	18.9
TOTAL SYSTEM	74.9

Source: Exhibit HO-DMP-1.

of specific demand management technologies" (Exhibit HO-DMP-2). Furthermore, the Companies asserted that "[p]erforming a specific technology based analysis would have added to the complexity of the study and actually subtracted from its credibility" (Exhibit HO-DMP-2).

The Siting Council agrees that the approach taken by the Companies -- to evaluate generic demand-side management strategies as opposed to specific technologies or programs -- may be appropriate as a screening device when analyzing the cost-effectiveness of different supply options. However, the Companies must also show that their load management projections are realistic both in terms of (1) the ability of the end-uses in the System to "deliver" the targeted levels of "supply" (or peak reduction) and (2) the level of load managment that is cost-effective relative to other resource options. To ensure that this is the case, the Siting Council requires information on the viability and cost-effectiveness of proposed demand management strategies similar to that presented by the Companies in their previous Forecast.

Accordingly, the Siting Council ORDERS the Companies to present information on their existing and proposed demand management programs which will enable the Siting Council to evaluate the effectiveness of these programs as elements of a cost-effective, reliable and feasible supply plan.

The Siting Council FURTHER ORDERS the Companies to demonstrate that they have explored possible reliance on demand management strategies as part of their contingency planning/sensitivity analyses in a way that parallels their investigation of generation options. Specifically, the Companies must explore the effects of other contingencies on the cost-effectiveness of different levels of demand management.

c. Alternative Resources/Qualified Facilities

In its review of COM/Electric's previous supply plan the Siting Council found that "the System's passive approach to cogeneration is inconsistent with its pending capacity short-falls and the need for diversity of its fuel sources ... and appears to be inconsistent with its aggressive and laudatory approach to development of alternate energy projects." 12 DOMSC 39, 83 (1985). To address this deficiency the Siting Council ordered the System to forecast its potential for acquisition of capacity and energy from cogeneration, and its potential for peak reduction from customer self-generation.

The Companies have presented a schedule of capacity available from Qualifying Facilities. The Companies should continue to submit such information in future filings.

The Siting Council also ordered COM/Electric to "survey cogeneration potential among its large industrial customers that have already indicated an interest in self-generation, as well as those smaller industrial and commercial customers that may be attractive candidates for modular cogeneration units." 12 DOMSC 39, 83 (1985). The Companies' current filing fails to address those requirements (Exhibit HO-SPP-17). Therefore, the Siting Council ORDERS the Companies to comply with this condition.

COM/Electric's 1986 Forecast shows that the Companies expect to rely upon an additional 60 MW of QF capacity from as-yet unidentified sources by 1995. The Companies currently have approximately 70 MW either in operation or construction (Forecast at 20). The SEMASS resource recovery facility accounts for 40 MW and the Boote Mills (22.9 MW) and Swift River (4.5 MW) hydro projects account for another 27.4 MW.

COM/Electric believes that its avoided costs will be "higher than neighboring utilities with higher percentages of nuclear and coal in their generation mix" (Exhibit HO-SPP-7b). The Companies assert that given their higher avoided cost rates and willingness to contract for projects outside of their service territory, they "should be in a good position to acquire a significant share of the alternative resource market" (Exhibit HO-SPP-7b).

The Companies have recently signed a contract with Consolidated Power Company for the output of its 25 MW cogeneration project in Lowell. This contract reduces the amount of capacity needed to satisfy the Companies' goal to 35 MW by 1995 (Exhibit HO-SPP-19). The Siting Council finds that the Companies' goal of an additional 35 MW of QF capacity by 1995 is realistic and hence the Companies' reliance on these resources does not threaten the adequacy of the Companies' long-run supply plan. On the contrary, the Siting Council notes that cost-effective QF contracts could be used to reduce supply planning risks and as a means of responding to contingencies, given the relatively short lead-time for these projects. The Siting Council encourages the Companies to consider using QFs to reduce supply planning risks and expects that the Companies' upcoming implementation of a request-for-proposals process for QF contracts as ordered by the Massachusetts Department of Public Utilities ("DPU") in Docket No. 84-276-B (1986) will support the Companies' QF contracting goals.

d. Pt. Lepreau

Currently, COM/Electric purchases 25 MW of capacity from Pt. Lepreau Unit 1. The Companies are investigating a number of possible alternatives for securing additional capacity from the New Brunswick Power Commission's ("New Brunswick Power") Pt. Lepreau station. One such option is to extend the Companies' contract with New Brunswick Power for Pt. Lepreau Unit 1 beyond October 31, 1991. (Exhibit HO-CSS-1a). Another option relates to New Brunswick Power's expressed interest in building a second unit at the Pt. Lepreau site. COM/Electric has had discussions with New Brunswick Power regarding both of these supply options (Exhibit HO-CSS-1a). However, New Brunswick Power has been unable to obtain commitments from utilities for the 400 MW needed to justify a second unit at Pt. Lepreau (Exhibit HO-CSS-2a).

Therefore, given the status of the proposals, the 50 MW of capacity from Pt. Lepreau available in 1992 set forth in the Companies' supply plan is more of a target than a likely supply source. If the 50 MW are not available then the Companies could replace this resource by accelerating their installation schedule for gas turbines. Thus, the Siting Council finds that the 50 MW from Pt. Lepreau are not needed to ensure the adequacy of the Companies' supply plan. Accordingly, the Siting Council finds that the possible inability of the Companies' to secure 50 MW of capacity from Pt. Lepreau in 1992 would not threaten the adequacy of the Companies' resources in the long run.

e. Installation of Gas Turbines

The Companies' supply plan, as presented in Table 2, shows the installation of a 75 MW gas turbine in each of the following years: 1996, 2001, 2003, and 2008 (Forecast at 33). The Companies assert that the lead time required for siting and installing a gas turbine is between thirty-six and fifty-four months (Exhibit HO-CSS-15).

Lead-time estimates are significant within a company's supply planning context, as they enable the Siting Council to evaluate a company's response time to unforeseen contingencies. In the case of COM/Electric, the Siting Council notes that the flexibility of the Companies' supply plan could be increased and hence the risks of contingencies reduced, by shortening the lead-time required for siting and installing new generating units (or for that matter, by being able to implement other strategies with even shorter lead times). Therefore, the Siting Council encourages the Companies to investigate innovative strategies for reducing the lead-time required for siting and installing new generating units.

As noted above, the Companies' supply plan calls for the installation of four gas turbines. The Siting Council notes, however, that the Companies have not identified in their Forecast the proposed sites for these units. The Siting Council requires such siting information be provided by companies in filings whenever their supply plans or their contingency plans indicate that a gas turbine would be built within a time frame bounded by the company's conservative estimate of the lead time required for siting and installing a gas turbine. Such information is necessary to ensure that plans relying on successfully sited gas turbines are, in fact, a viable strategy for meeting the company's long-run requirements.

In COM/Electric's case the results of the Companies' contingency analyses indicate that in no case would a gas turbine be built before 1991. If, however, in future filings the Companies' plans or contingency plans call for installing a gas turbine in the short run, then the Companies must provide information on the availability of sites for new generating units, as well as plans for siting these units, including information on the infrastructural (e.g., proximity of gas pipelines and transmission lines), land, and resource (e.g., availability of cooling water) requirements.

3. Conclusions on the Adequacy of Supply

For each of the contingencies the Companies evaluated (see Table 3), the Companies' supply plan ensures an adequate supply. However, the Siting Council finds that the Companies have failed to consider a critical contingency -- the delay or loss of Seabrook 1 (See Section III.E.1.a.). Nor have they evaluated the affect on their supply plan of a reasonable range of double contingencies, e.g., the loss or delay of Seabrook 1 and the concurrent loss or delay of the SEMASS project. As indicated in Sections III.E.1.a. & III.E.1.b., the Companies assume that neither of these projects will be available in the summer of 1987.

So while the Companies have responded to the Siting Council's previous order that they provide a sensitivity analysis and contingency plans, the Siting Council cannot find that COM/Electric evaluated a reasonable range of contingencies. To ensure that the Companies consider a full range of reasonable contingencies in the future, the Siting Council ORDERS the Companies in future forecasts to evaluate the impact on resource adequacy of the loss or delay of each supply addition (i.e., power purchases, construction projects, and demand-management options), including a reasonable range of critical double contingencies.

4. Least Cost Supply

Based on the information presented by the Companies, the Siting Council believes that the Companies' gas turbine strategy offers the system many advantages, including flexibility, quick response time to contingencies, and a low-cost means of adding capacity. Additionally, the Siting Council finds that among the options evaluated through means of the LMSTM methodology, a gas turbine strategy offers the least cost plan.

However, the Siting Council notes that due to three flaws in the way the Companies have implemented their supply planning methodology, the Siting Council cannot find that the Companies' supply plan actually ensures a least cost energy supply. The first problem is COM/Electric's failure to fully evaluate the cost-effectiveness of non-generation alternatives. The second problem is that the Companies only compared alternatives over a twenty-five year forecast horizon rather than on a life-cycle cost basis and thus could have under-counted the fuel cost savings offered by more capital intensive technologies (e.g., combined cycle and base load coal plants). The third problem is COM/Electric's failure to evaluate more than one type of generation alternative for each scenario.

a. Comparison of Alternatives on an Equal Footing

The Companies did not evaluate the costs and benefits of non-generation alternatives to the same degree as generation alternatives. First, the Companies provided little evidence in support of the engineering viability of their targeted levels of demand management and purchases from cogeneration or small power facilities. Second, the Companies presented no information on the costs of company-sponsored conservation and load management or of power purchases from cogenerators and small power producers. Furthermore, the Companies have assumed across all of their plans and contingency plans a fixed level of supply from such demand-side strategies and from purchases from independent power producers. Consequently, the Companies have failed both to compare directly non-generation alternatives to generation alternatives and to demonstrate that their supply plan and planning process ensures a least-cost supply.

While it may be difficult for the Companies to evaluate the relative economics of their targets for purchases from small power producers or cogenerators given that no contract information is available and the size of the target identified in the current Forecast is itself speculative,[10] the Siting Council believes that the Companies have not evaluated adequately in either their sensitivity analyses or their contingency plans the role of these resources in meeting COM/Electric's capacity and energy requirements.

For example, the Companies' response to the cancellation of either the Hydro Quebec Phase 2 or SEMASS projects would be to increase their purchases from other NEPOOL participants prior to 1991 and then to accelerate the installation schedule for gas turbines (Forecast at 89-94, 69-74). See Section III.E.1.c & III.E.1.b. No consideration is given in the Companies' analysis as to how either of these events would affect the Companies' long-run avoided costs and therefore the potential for the Companies to enter into contracts for cogeneration and small power production (or for conservation and load management, for that matter). The cancellation of a project that was part of a least cost supply plan presumably would increase the System's long-run avoided (i.e., marginal) costs such that increased amounts of cogeneration and small power production (or conservation and load management) might become cost-effective. The Companies' analysis takes no consideration

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[10] Particularly, under the DPU's rules governing sales of electricity to utilities from small power producers and cogenerators, QFs will have the opportunity in the future to bid on the right to supply the Companies' capacity requirements, in direct competition with the utility. See D.P.U. 84-276-B.

of this effect. The Siting Council believes that this failure to evaluate the impact of the cancellation of these projects on the relative attractiveness of non-generation alternatives is indicative of the way the Companies' used a relatively "neutral" supply planning process but gave greater consideration to conventional generation alternatives.

Similarly, the Siting Council believes that the Companies did not fully evaluate load management. This is particularly significant given the Companies' stated need for additional capacity to meet peak loads, rather than for energy. No information on the costs or benefits of load management strategies is presented. Without this information, the Siting Council is unable to evaluate the cost-effectiveness of the Companies' peak-load reduction target of 75 MW by 1995. Nor can the Siting Council be sure that the potential for cost-effective load management in the Companies' service territory is only 75 MW. Consequently, the Siting Council cannot conclude that the Companies' supply plan ensures a least-cost power supply.

In many ways, the supply planning methodology presented by the Companies is a traditional generation expansion analysis. While the analytical techniques themselves are capable of analyzing a full range of strategic options, the Companies have used this methodology in a way that fails to consider non-generation alternatives on the same basis as generation alternatives. The Companies essentially acknowledged this when they stated:

> The intention of the analysis (i.e., analysis of the economics of different demand management strategies) was to test the sensitivity of the different new generation strategies (i.e., gas turbine, combined cycle, coal) to the effects of generic load shape changes, not to evaluate the economics of specific demand management technologies[11] (Exhibit HO-DMP-2).

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[11] However, in the Forecast the Companies state that "new generation will be added to the system whenever the total system capability falls (Footnote Continued)

The Siting Council has consistently held that a reasonable range of alternatives should be compared on an equal basis and that a reasonable range must include conventional and non-conventional supply options. Massachusetts Electric Company et al., 13 DOMSC 119, 178, 179. Petitions for approval of new generating facilities or associated transmission facilities must demonstrate that the preferred alternative ensures the least-cost power supply and that a reasonable range of alternatives have been considered.

In this case, the Companies stated they are committed to fully developing non-generation alternatives before installing additional generation (Forecast at ii). The Siting Council finds, however, that unless the Companies demonstrate that they are actually comparing a full range of alternatives on an equal basis, then the Companies will not be able to know that they have selected appropriate targets for demand-management and for purchases from independent power producers -- that is, whether targets are too high or too low in terms of contributing to ensuring a reliable, least-cost supply. Accordingly, the Siting Council ORDERS the Companies to compare generation and non-generation alternatives on an equal footing in future supply plans as well as in applications for the construction of energy facilities.

b. Time Frame for Comparison of Alternatives

The Siting Council finds a second instance of the Companies' supply plan's failure to demonstrate that it has ensured a least cost supply: the supply plan presented by the Companies in the current Forecast uses a twenty-five year time horizon for analytic purposes. While a forecast horizon longer than ten years is valuable to the Siting Council's supply

(Footnote Continued)
below the capability responsibility requirement and will be considered on an equal basis with all other reasonable options. New generation is not the only supply planning solution, nor is it ruled out as an option" (Forecast at 2).

plan review given the long lead-time required for large generating facilities, planning analyses that rely on only twenty-five years of projected data are inherently biased in their treatment of options with economic lives that are longer than twenty-five years. Any resource option whose benefits exceed its costs beyond the twenty-five year cut-off period will be under-valued in the Companies' analysis.[12] Thus, for a gas turbine built in 1996 (consistent with the Companies' supply plan), the relatively high variable costs for the last sixteen years of the units' twenty-five-year useful life are not considered. Similarly, for a combined-cycle plant built in 1996, the fuel-cost savings for the last sixteen years of the plant's life are not considered. Since combined cycle units offer variable cost savings relative to gas turbines, then by failing to consider the variable cost savings of the last sixteen years of the units' life, the Companies have failed to present analytic results that adequately demonstrate that gas turbines ensure a least cost power supply.[13] In the analysis presented by the Companies, gas turbines may appear more favorable than they in fact may be.

The Siting Council refrains from rejecting the Companies' supply plan on this basis because the Siting Council is articulating this standard for the first time in this case and because the Companies

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[12] In support of this practice, the Companies assert that the present value of fuel savings outside of the forecast horizon is negligible (Exhibit HO-CSS-11b). The Companies use a thirteen-percent discount rate, based on their weighted average cost of capital (Forecast at 13). The Siting Council acknowledges that at a 13-percent discount rate the present value of one dollar to be received in twenty-five years is only 4.71 cents. However, since the Companies are proposing to have the first of these units operational in 1996, the fuel costs of only the first fourteen years of the unit's life are being considered representing only fifty-six percent of a gas turbine's useful life.

[13] The Siting Council wonders whether one reason why the Companies only compared alternatives over a twenty-five year time horizon was the twenty-five year limit on the LMSTM analysis period. If so the Siting Council questions the appropriateness of using LMSTM to evaluate generation alternatives in a long-range planning analysis.

forecast and supply planning analyses show that COM/Electric does not yet need to embark on an action plan with respect to securing long-run capacity additions for a few more years. However, in future filings, the Siting Council ORDERS the Companies to compare alternatives on the basis of their full life-cycle costs and benefits when presenting to the Siting Council long-range supply plans and applications for construction of new facilities.

The Siting Council notes that the Companies only compared alternatives over a twenty-five year time horizon due to the twenty-five year limit on the LMSTM analysis period (Exhibit HO-GI-7b). Together, this limited analysis time period, the consequent inability of the model to properly deal with end-effects (i.e., where differences between the costs and benefits of different generation alternatives are not reflected in the analysis period), and the number of manual iterations of LMSTM required to compare a full range and mix of generation alternatives under a full range of contingencies (Tr. at 105), indicate to the Siting Council that LMSTM may not be an appropriate model to use for long-range supply planning. Furthermore, the Siting Council notes that the Companies' own description of the supply sub-model states that the sub-model "has been specifically developed to account for the effects of demand management strategies" (Forecast at 45). This causes the Siting Council to further question the appropriateness of the Companies' use of LMSTM as a comprehensive long-range supply model. Accordingly, the Siting Council ORDERS the Companies in their next filing to demonstrate the appropriateness of LMSTM for use in long-range supply planning studies.

c. Mix of Generation Alternatives Evaluated for Each Scenario

When evaluating different generation expansion plans for the base case and for each of the contingencies, the Companies only evaluated one type of generating capacity at a time for each contingency or scenario. That is, if in the contingency or scenario additional generating capacity is needed in 1996, 2001, 2003, and 2008, then gas turbines would be added in each of these years. In an alternative analysis, only combined cycle units would be added in each of those years. In no case did the Companies explore adding a mix of gas turbines, combined cycles, and coal units for each scenario (Tr. at 65). By failing to evaluate a mix of generation options when analyzing each scenario, the Companies failed to consider a reasonable range of generation alternatives for their scenarios. Therefore, the Siting Council cannot find that the Companies' supply planning methodology ensures a least cost supply of power. Accordingly, the Siting Council ORDERS the Companies in the future filings to evaluate a reasonable mix of expansion plans or resource mixes for each scenario.

5. Diversity of Supply

COM/Electric depends heavily on oil to meet its energy requirements. As Table 5 shows, in 1985 oil-fired generation provided 58.3 percent of the Companies' energy requirements. Moreover, 79.0 percent of the Companies' capacity is provided by oil-fired units of which two-thirds is from residual-oil units (a fourth of which can also burn natural gas) and one-third is from distillate-oil units (Exhibit HO-3, p. 3).

TABLE 5

COM/Electric System

Actual and Forecasted Energy Mix

for 1985, 1990, and 1995
(GWH)

	1985	(%)	1990	(%)	1995	(%)
Residual Oil	2,389	58.1%	2,460	52.1%	2,635	51.6%
Distillate Oil	8	0.2%	103	2.2%	39	0.8%
Natural Gas	217	5.3%	---	---	276	13.2%
Nuclear	1,279	31.1%	1,356	28.7%	1,190	23.3%
Small Power	30	0.7%	551	11.7%	714	14.0%
Hydro	---	---	248	5.3%	248	4.9%
Miscellaneous*	189	4.6%	---	---	---	---

Source: Exhibit HO-3 pp. 3-5.

* Miscellaneous includes energy from short-term transactions and NEPOOL energy services.

COM/Electric projects that its reliance on oil will be reduced in the future by nuclear energy from Seabrook 1, hydro-electric energy from Hydro Quebec, and alternative energy resources. Although these non-oil resources represent a significant contribution to the Companies' resource mix, the Siting Council notes that the net effect of these additional resources on the Companies' oil requirements will be relatively small -- oil-fired generation is projected to account for 52.4 percent of the System's total energy requirements as opposed to 58.3 percent in 1985.

Therefore, the Siting Council encourages the Companies to continue to attempt to reduce their reliance on oil-fired generation and to give full consideration to the benefits offered by supply sources which increase the diversity of the Companies' fuel mix.

6. Summary of the Analysis of the Supply Plan

The Siting Council finds that the Companies' new supply planning methodology as presented in their 1986 Forecast is an innovative approach and addresses some of the concerns expressed in the Siting Council's rejection of the Companies' last supply plan. While the Siting Council has determined that the Companies' supply plan is adequate despite some of the serious problems addressed earlier, we expect that the Companies will be able to establish that they have an action plan to provide adequate supply in the short-run.

The Companies' planning methodology does offer a valuable tool with potential to help the Companies identify least-cost strategies for meeting the System's capability responsibility in all upcoming years of the forecast period. However, the Siting Council cannot determine whether the way in which the Companies have implemented their methodology has produced a supply plan and contingency plans that will actually ensure a least-cost power supply. While the Siting Council finds that the Companies' use of their planning methodology has enabled them to identify the least-cost strategies from the array of options analyzed, the Siting Council cannot determine that the Companies have analyzed a reasonable range of supply alternatives. The Companies failed to fully evaluate non-generation alternatives on an equal footing with generation alternatives and to compare the costs and benefits of even those generation alternatives on a life-cycle cost basis.

To enable it to make a determination that the Companies have evaluated a reasonable range of supply alternatives in future cases, the Siting Council ORDERS the Companies to evaluate demand-management alternatives in a similar analytical fashion as generation alternatives, and to evaluate all options on the basis of their life cycle costs within a framework of analysis that relies on comparing alternatives in terms of their net present value of revenue requirements.

IV. ORDER AND CONDITIONS

The Siting Council hereby approves, subject to Conditions, the 1986 Supplement to the Second Long-Range Forecast of Electric Power Needs and Requirements of the Cambridge Electric Light, Canal Electric, and Commonwealth Electric Companies. As discussed herein, the Siting

Council approves, subject to six conditions, the Companies' supply plan: Accordingly, it is ORDERED:

1. That the Companies provide within sixty days a contingency analysis and action plan that outlines how they will meet their projected peak loads and reserve requirements in the summer of 1987.

In the next forecast, to be filed on or before September 1, 1987, it is FURTHER ORDERED:

2. That the Companies present information on their existing and proposed demand management programs which will enable the Siting Council to evaluate the effectiveness of these programs as elements of a cost-effective, reliable and feasible supply plan.

3. That the Companies survey cogeneration potential among their large industrial customers that have already indicated an interest in self-generation, as well as among those smaller industrial and commercial customers that may be attractive candidates for modular cogeneration units.

4. That the Companies present contingency planning and sensitivity analyses which evaluate loss or delay of each supply addition, including demand management, as well as a reasonable range of double contingencies.

5. That the Companies compare a reasonable mix of generation and non-generation alternatives and compares them on an equal footing in future supply plans and in applications for the construction of transmission lines and generating facilities.

6. That the Companies compare alternatives on the basis of their full life-cycle costs and benefits.

7. That the Companies demonstrate the appropriateness of LMSTM for use in long-range supply planning studies.

Robert D. Shapiro

Robert D. Shapiro
Hearing Officer

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council by the members and designees present and voting: Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs); Joellen D'Esti (for Joseph D. Alviani, Secretary of Economic and Manpower Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Stephen Umans (Public Electricity Member); Madeline Varitimos (Public Environmental Member); Joseph W. Joyce (Public Labor Member). Ineligible to vote: Dennis J. LaCroix (Public Gas Member). Absent: Elliot J. Roseman (Public Oil Member).

Sharon M. Pollard

Sharon M. Pollard
Chairperson

3 November 1986

Date

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of Taunton Municipal Lighting Plant's Long-Range Forecast of Electricity Needs and Resources	EFSC No. 85-51

FINAL DECISION

Hearing Officer
Robert D. Shapiro

William S. Febiger
Staff Analyst
On the Decision

The Energy Facilities Siting Council ("Siting Council") hereby APPROVES with conditions the 1984 Forecast Supplement ("Supplement") of the Taunton Municipal Lighting plant ("TMLP"). This Supplement covers TMLP's projections through the 1993-94 winter season.

I. INTRODUCTION AND PROCEDURAL HISTORY

TMLP is a publicly owned utility of the City of Taunton, serving Taunton and surrounding areas in the town of Raynham, and portions of the towns of Berkley, Lakeville, and Dighton. TMLP is a stand-alone member of NEPOOL, and operates a 110 megawatt ("MW") combined cycle generating plant, as well as a 25 MW oil peaking unit, in Taunton.

TMLP filed its 1984 Supplement on July 15, 1985.[1] TMLP provided notice of this Adjudication by publication and posting in accordance with the Hearing Officer's instructions.

On April 9, 1986, the Siting Council Staff ("Staff") issued preliminary information requests for purposes of technical session. A technical session was held between the Staff and representatives of TMLP on May 5, 1986. The first set of information requests was issued on June 20, 1986, with responses due July 8, 1986. TMLP provided its responses September 22, 1986.

II. COMPLIANCE WITH PREVIOUS CONDITIONS

The conditional approval of TMLP's last forecast in EFSC Docket 83-51 specified that four demand conditions and four supply conditions be met. In Re Taunton Municipal Lighting Plant, 10 DOMSC 252, 276 (1984).

A. Demand Conditions

Previous Condition 1 required that TMLP test other econometric model formats beyond linear regression for all its customer classes. TMLP has tested a non-linear model for the residential base class, and presented reasons why it believes the linear format is more appropriate. Information Response 3. The Siting Council accepts TMLP's compliance with this condition.

Previous Condition 2 required that TMLP test residential class model runs reflecting customer characteristics such as personal income and household size. TMLP has successfully incorporated personal income as an independent variable in forecast models for the residential base class and electric hot water class. See Section III-C, infra. The Siting Council finds that TMLP has complied with this condition.

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[1] The filing date, originally set for October 1, 1984, was extended three times in response to written motions filed by TMLP on September 17, 1984 and February 15, 1985, and an oral motion made by TMLP on January 14, 1985.

Previous Condition 3 required that TMLP work toward reflecting price and conservation trends in its forecast for the residential electric hot water class. TMLP substantially improved its forecast for this class by successfully modeling sales as a function of price and personal income. Supplement, P. II-14. The Siting Council finds that TMLP has complied with this condition.

Previous Condition 4 required that TMLP begin disaggregating current and future industrial sales data by two-digit SIC code. TMLP presented such a disaggregation for a typical month. The Siting Council finds that TMLP has complied with the condition, but as part of this Decision is requiring follow-up reporting and analysis, and discussion of forecasting implications. See Section III-E, infra.

B. Supply and Conservation Load Management Conditions

Previous Condition 1 required that TMLP report on the effectiveness of improvements to its combined-cycle plant Cleary 9 in maintaining availability factors. TMLP presented data demonstrating improved availability levels, and thus has complied with this condition. Supplement, P.IV-5.

Previous Condition 2 required that TMLP discuss its plans to enhance the economic viability of Cleary 9. TMLP is following through on plans to fully convert Cleary 9 to burn natural gas as well as oil. See Section IV-B-1, infra. The Siting Council finds that TMLP has complied with this condition.

Previous Condition 3 required that TMLP investigate methods to bring about increased purchases of customer-owned generation. TMLP has analyzed cogeneration potential, particularly as related to prospects for a steam district heating-cooling system, and provided technical assistance to prospective cogenerators. The Siting Council finds that these efforts are partially responsive to the condition. TMLP did not present its consideration of financial and contractual methods for fostering customer-owned generation as required in previous Condition 3. See 10 DOMSC 252, 274. Thus, the condition is reinstated as part of this Decision. See Section IV-C-2, infra.

Previous Condition 4 required that TMLP discuss progress or plans regarding appliance use surveys and demonstrate consideration of conservation and load management strategies as part of an integrated supply planning approach. TMLP discussed progress regarding appliance use surveys for the industrial class, but not other classes. TMLP discussed its progress in developing an integrated supply planning approach, but did not show how consideration of conservation and load management is being or can be integrated. Thus, the Siting Council finds that TMLP partially complied with the first part of the condition concerning customer surveys, but did not comply with the second part of previous Condition 4 concerning integrated analysis of conservation and load management. The condition is reinstated as part of this Decision See Section IV-E, infra.

III. DEMAND FORECAST

A. Background & 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", Mass. Gen. Laws Ann. ch. 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". Mass. Gen. Laws Ann. ch. 164, sec. 69J.

To ensure that the foregoing standard is met the Siting Council applies three standards to demand forecasts: 1) reviewability, i.e., whether the results can be evaluated and duplicated by another person, given the same level of technical resources and expertise; 2) appropriateness, i.e., whether the forecast methodology is technically suitable to the size and nature of the utility's system; and 3) reliability, i.e., whether the methodology instills confidence that the data, assumptions and judgments produce a forecast of what is most likely to occur. In Re Boston Edison Company, 10 DOMSC 203, 209 (1984).

TMLP has forecasted total electrical energy requirements for its system to grow from 348,120 megawatt hours ("MWH") in 1983 to 445,180 MWH in 1993; this is equivalent to a 2.5 percent annual compound growth rate. For the same ten-year period, the winter peak also is forecasted to grow at a 2.5 percent equivalent annual compound rate, from 63.2 MW to 80.9 MW. Supplement, P.V-2. Table 1 compares base period and forecast period growth rates for the respective classes.

TABLE 1
Sales Growth Rates of Customer Classes

	Compound Average Annual Percentage Change	
Class	1970-83	1983-93
Residential:		
Base Rate	3.6	2.4
Electric Heat	7.7	2.1
Domestic Hot Water	-0.5	0.1
Commercial	7.1	2.3
Industrial	1.3	4.0
Street Lighting	1.6	-2.3
Total Sales	2.7	2.8
Total Requirements*	2.8	2.5

* Includes internal use and losses.

Based in part on staff calculations.
Source: Supplement, P. V-1

B. Overview of Forecast Methodology

In its previous forecast, TMLP introduced econometric models to forecast sales for the residential, residential heating, commercial and industrial classes. In the current forecast, TMLP again has relied on econometric modeling for those classes and extended it to cover the fifth class -- residential hot water.

The econometric models in TMLP's forecast continue to be based on a linear regression format. Since the last filing, however, TMLP had added one additional explanatory variable to three of its class-by-class models -- incorporating personal income into the residential and commercial class models, and degree days into the industrial class model. See Section C, D, and E, infra.

As in past filings, TMLP has provided information on known new development projects and their prospective electrical requirements. The information serves as a cross-check on TMLP's statistical models. Supplement, P. V-34 to V-36.

C. Residential forecast

Residential sales are forecast for three classes -- base rate, electric heat and electric hot water. Together, they account for 34.7 per cent of total 1993 system sales. In 1983, there were 15,190 base rate customers, 1,205 electric heat customers, and 3,940 hot water customers. Supplement, PP. V-5 to V-7.

The aggregate sales for the three residential classes are forecasted to increase at an annual compound rate of 1.8 per cent between 1983 and 1993. The forecasted rates of annual change among the individual classes range from flat in the hot water class to +2.4 per cent in the base-rate class.

For both the base-rate and heating classes, the forecasted rates of sales increase are about one-third higher in the current forecast, as compared with the previous forecast prepared two year earlier. 10 DOMSC 252, 257. This result is consistent with changes in the independent variables used in TMLP's models since the previous filing, including a sizable drop in the expected rate of increase in price and, in the case of the base-rate class, the effect of adding personal income as a second driving variable. Supplement, PP.V-18, V-26.

TMLP's current forecast demonstrates three accomplishments that are responsive to concerns previously raised by the Siting Council. The accomplishment are:

- the addition of personal income as a second driving variable in the base class, reducing reliance on population;
- the testing of a non-linear regression model format for the base class; and
- the successful modeling, for the first time, of the hot water class. Supplement, PP. II-2, II-14; Information Response 3.

TMLP's efforts in testing new independent variables and a non-linear format for the base-rate class are a response to the Siting Council's concerns about the high elasticity of sales to the independent variable population in the previous forecast. Supplement, P. III-2 to III-3. The Siting Council questioned the reliability, for forecasting purposes, of a modeled relationship in which, other factors being equal, electricity sales are expected to increase at a constant rate over time of two-to-three times the rate of increase in population. 10 DOMSC 252, 259.

TMLP has provided data indicating that the mean elasticity of base-rate class sales to population is 32 percent lower in the current forecast than the previous forecast. However, the elasticity is still greater than two. Supplement, P. III-5.

TMLP has argued that the elasticity of sales to population embodied in the base-rate model reflects electricity use factor changes from both the addition of new homes and changes in per-capita usage in existing homes, and is thus not surprising. Information Response 3. However, TMLP has not provided any data comparing either per-capita or per-customer usage levels between existing homes and new homes.

TMLP also has failed to discuss the possible extent to which changes in average number of persons per household may account for any changes in per-capita usage levels in existing homes. Instead, TMLP has argued that it is "not presently aware of any circumstances which would indicate a deficiency in the forecasting methodology on account of a lack of consideration of family size." Supplement, P. II-4.

Yet, between 1970 and 1983, the total number of residential customers increased 25.9 per cent and the number of base-rate customers increased 25.2 per cent, while service area population increased only 12.5 per cent. Thus, average household size clearly was decreasing over the base period. Supplement, PP. V-20, V-24, V-28. At the same time, the forecast shows that total residential and base-class residential sales increased by 40.9 per cent and 58.6 per cent, respectively. Supplement, P. V-1. Thus, there appear to have been sizable increases in per-capita usage.[2] Any such increase with respect to base-rate customers is only partially explained by other independent variables, i.e., income and price, as evidenced by the modeled elasticity of base-rate sales to population.

What is unclear is the extent to which any past increases in per-capita usage may have simply reflected decreases in household size, as opposed to increases in the propensity of customers to acquire and use electrical devices. Reductions in household size could be significant for components of usage which are to a greater or lesser extent collective (e.g., lighting, refrigeration, television viewing). If any effects of decreasing household size are imbedded in TMLP'S base period data, then awareness of the likely relationship of past and expected trends in household size is important to the reliability of the forecast.

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[2] An increase in per-capita usage clearly occurred for residential customers in aggregate, but is only implied for the base-rate (or any other) class since population by class is not known.

Still, the Siting Council continues to find that TMLP's residential forecast modeling is appropriate for a system of TMLP's size. However, the Siting Council notes that most larger electric systems in Massachusetts now use end use modeling in their residential class forecasts,[3] and thus employ a more household-based form of forecasting than TMLP. TMLP should supplement its econometrically based forecasting approach with reporting and analysis that can help detect any differences in usage patterns between new and existing customers, and any potentially related trends in household characteristics.

As a CONDITION of approval of its long-range forecast, TMLP shall provide in its next filing an analysis which compares, by residential rate class in 1986, average full-year usage levels of "new" customers connected in 1985 with "old" customers connected prior to 1985. TMLP also shall report and discuss the forecasting implications of the relative rates of change over the base period for service area population, total residential customers, and base-class customers.

D. Commercial Forecast

Commercial sales have shown an erratic pattern of change since 1970, more than doubling between 1970 and 1976, leveling out between 1976 and 1981, and rising 8.7 per cent between 1981 and 1983. Supplement, P. V-3. The forecasted annual compound rate of growth in commercial sales is 2.3 per cent. This compares with 1.6 per cent in the previous forecast, prepared before the recent pick up in sales. 10 DOMSC 252,257.

Based on TMLP's modeling, the resumption of sales growth in 1982 and 1983, and throughout the forecast period, appears to reflect the leveling of electricity prices since 1982 and expectations that future price increases will be more modest than those in the mid-to-late 1970's. In addition, the commercial model now includes as an independent variable personal income, which is expected to increase by $12,400 between 1983 and 1993, compared with a $9,000 increase between 1973 and 1983. Supplement, P. V-8.

TMLP has argued that historically its commercial sales largely were to customers serving a local retail market, internal to the utility's service area. Supplement, P. III-13 to III-14. Service area population, and now county personal income, have been presented as the appropriate variables to explain such sales. In the current filing, TMLP also has successfully introduced a dummy variable to explain the sharp increase in sales between 1972 and 1974, which TMLP attributes to the opening of the Taunton Mall and development along Route 44. Supplement, P. III-7 to III-10. The Siting Council approves of TMLP's methods in forecasting this component of commercial sales.

In the current forecast, TMLP also has noted the recent emergence of a new component in its customer base -- customers that are similar to non-process

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[3]Besides TMLP, only Nantucket Electric Company relies primarly on econometric models for forecasting residential sales. Fitchburg Gas and Electric Company currently relies on neither econometric nor end use models.

industrial customers but that buy electricity under the commercial class rate. TMLP says such customers are reflected in TMLP's listing of known planned commercial projects, which includes 21 projects expected to add 6,963 MWH in annual load over the next three years.[4] TMLP cites eight of these projects, accounting for 4,475 MWH of annual loads, as being examples of relatively large commercial businesses serving a national or regional market.[5] Supplement, p. III-12 to III-13, V-34.

TMLP acknowledges that it may need to adjust its forecast methodology in future filings to reflect this new type of commercial customer. TMLP believes these customers appear to be "similar to industrial customers, in being affected by price and national economic trends, and could possibly be modeled as such." Supplement, P. III-13 to III-14. Information Response 4.

The Siting Council largely concurs with TMLP's assessment of changes in TMLP's commercial customer base. Indeed, the Siting Council views TMLP's analysis and insights with respect to a "new type" of commercial-industrial customer as exemplifying the type of perspective the Siting Council believes TMLP should attain in forecasting its industrial sales, generally. Such a perspective can be attained by separating out important sectoral trends or patterns of sales change over time among various types of industrial customers. See Section E, infra.

E. Industrial Forecast

Industrial sales trends in recent years have reflected both cyclical trends in the national economy and some longer-term uncertainty about prospects for major process-oriented industrial sectors in the Taunton area. See 10 DOMSC 252, 262. Industrial sales accounted for 41 per cent of TMLP's 1983 system sales, and are thus of great importance to the reliability of TMLP's overall forecast.

Industrial sales in 1983 were 12.2 percent lower than in 1978, and only 3.5 percent higher than in 1973. Supplement, P.V-4. For the near future, TMLP has identified only three known industrial projects, which are expected to provide just over 2,000 MWH of additional load.[6] Supplement, P. V-35.

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[4]By way of comparison, TMLP's previous forecast showed only fourteen known commercial projects expected to add 3,118 MWH in annual load. 10 DOMSC 252,261.

[5]The forecast also indicates that an additional seven projects are under consideration at Myles Standish Industrial Park. Although unnamed, the projects are indicated by business type, and their annual load requirement estimated at up to 2,500 MWH. Supplement, P. III-36 to III-37.

[6]TMLP also states that 37 lots recently have been zoned as part of the West Industrial Park. The potential addition to annual load from full development of this park is estimated to be 10,700 MWH. Supplement, P. III-36, V-37.

Despite the limited evidence of ongoing growth in the industrial class, TMLP forecasts that industrial sales will increase 50,415 MWH over the next ten years. Supplement, P.V-14. The forecasted annual compound rate of growth is 4.0 per cent, well above all other classes. The forecasted rate of growth is nearly three-quarters higher than that in the previous forecast, although the industrial class was expected to be the fastest growing class in that forecast as well. 10 DOMSC 252, 257.

Since the previous forecast, TMLP has improved the backcasted fit of its industrial sales model by including degree days as an independent variable. However, as in the previous forecast, gross national product and price are the actual determinants of the forecasted trend in industrial sales. Supplement, P. V-14.

It is evident that TMLP's expectations for a sizable reduction in the rate of increase in price are having a profound effect on the forecast. While price per KWH increased from 2.07¢ to 7.54¢ between 1973 and 1983, it is forecasted to increase only to 9.39¢ by 1993. Id. However, If the expected absolute change in price between 1983 and 1993 was assumed to be the same as it was between 1973 and 1983, the projected 4.0 percent rate of increase in sales would be reduced by more than half, and 1993 sales would be nearly 30,000 MWH lower, than as modeled using TMLP's price assumptions.

The Siting Council does not question TMLP's price forecast. However, the Siting Council does question the reliability of a forecast model that embodies such wide swings in sales trends, as compared between the base and forecast periods, and that appears to attribute such swings largely to price. The Siting Council is not satisfied that the possible roles of other factors, not captured in the model, are being adequately considered.

In its previous decision, the Siting Council stressed the importance of considering sectoral changes as an underlying factor in explaining overall industrial sales trends. The Siting Council's concern was prompted by recent plant closures and production declines in the metals industry, a historically predominant sector of the local economy. 10 DOMSC 252, 262-3.

TMLP has begun to comply with the Siting Council's previous Condition 2, requiring disaggregation of current (and future) sales data by SIC code. See Section II-A, supra. By the time of its next filing, TMLP should have two or more years of disaggregated annual sales data. TMLP now should begin to apply such information, at least qualitatively, as part of its forecasting efforts.

The Siting Council notes that TMLP's discussion of the emergence of a "new type" of commercial customer similar to an industrial customer, may, in effect, represent an important insight concerning sectoral growth patterns. See Section D, supra. The acknowledgement that industrial growth is not occurring as much in process-oriented industries, as in industries whose electrical requirements are such as to allow use of a commercial class rate, may be a key element of the overall understanding that would emerge from a fuller sectoral analysis of TMLP's commercial-industrial customer base.

TMLP should undertake an overall review of sectoral trends as background for any consideration of modeling changes to reflect the new type of commercial-industrial customer. As a CONDITION of approval of its long-range forecast, TMLP shall in its next filing provide compilations of annual industrial sales by SIC code for all available years from 1984 through 1986, discuss implications of sectoral trends for its forecasting in general, and report as appropriate on its consideration of specific modeling changes to the industrial and/or the commercial class to better capture sectoral growth patterns.

IV. ANALYSIS OF THE SUPPLY PLAN

A. Background and Standard of Review

In keeping with its mandate to "provide a necessary power supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost," Mass. Gen. Laws Ann. ch. 164, sec. 69H, the Siting Council consistently reviews three dimensions of a utility's supply plan: adequacy, diversity, and cost.[7] 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. 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. COM/Electric, 12 DOMSC 39, 72 (1985). The Siting Council also addresses whether a supply plan minimizes the long-run cost of power subject to trade-offs with adequacy, diversity, and the environmental impacts of construction and operation of new facilities. Finally, the Siting council reviews utility demand management programs, cogeneration projects and small power production efforts on the same basis as the consideration of new conventional bulk power facilities when analyzing the adequacy, diversity, and cost of a supply plan. In Re COM/Electric, 12 DOMSC 39, 72 (1985). In Re Eastern Utilities Associates, 11 DOMSC 61,96 (1984).

Recently, the Siting Council has started reviewing in greater detail the supply planning processes utilized by utilities, with the objective of assessing the extent to which these processes facilitate the development of long-range supply plans that are least-cost, adequate, and diversified. Recognizing that supply planning is a dynamic process undertaken under evolving circumstances, the Siting Council believes that a utility's supply plan should identify a variety of supply options based on identified and explained criteria. A company's consistent and systematic application of such criteria of supply planning decisions would instill confidence in the Siting Council that a utility is fully evaluating new projects, contracts, or purchases, and alternatives in a manner that leads the Company to produce a power supply that is a least-cost and minimum environmental impact. In Re Fitchburg Gas Electric, 13 DOMSC 85, 102 (1985).

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[7] TMLP asserts that its current supply plan does not require Siting Council approval because TMLP is not planning to construct a facility subject to Siting Council jurisdiction. Supplement, P. IV-1. In response to a similar TMLP assertion in the previous Siting Council proceeding, the Siting Council affirmed that it does have authority to rule on all supply plans of jurisdictional electric companies. 10 DOMSC 252, 254.

Rather, cost and diversity of supply have been the principal concerns in past Siting Council reviews of TMLP's forecast. In fact, the disposition of excess capacity from Cleary 9, which historically has been dispatched as an intermediate rather than a base-load unit, is itself a major factor in TMLP's long term planning in connection with minimizing the cost of supply. Many of the changes TMLP has made in its supply plan since the previous filing involve efforts to improve the efficiency of and sign contracts for Cleary 9.

In Summer, 1985, TMLP had entitlements to 77.6 MW of generating capacity to serve current requirements. Cleary 9 accounted for 35.7 MW, or 46 per cent, of TMLP's entitlement.[8] Table 2 shows TMLP's existing entitlements, including ownership and purchase agreements.

TMLP's sales of Cleary 9 capacity to Montaup Electric Company (Montaup), which amounted to 63.3 MW in 1985, are due to be phased out by 1987-88. Additional capacity expected to come on line early in the forecast period includes TMLP's 1.15 MW share of Seabrook 1. However, TMLP's capacity purchase contract with Montaup for 10 MW of Canal 2 expires at the end of 1986-87. In the absence of any additional agreements to sell excess capacity, TMLP's system reserve is projected to reach a maximum of about 90 per cent in 1987-88, and decline thereafter with growth in demand. Supplement, P. V-45.

B. Cleary 9

1. Conversion to Natural Gas

As a result of increased availability of natural gas at competitive prices, TMLP has embarked on a program to fully convert the Clearly 9 combined cycle plant to burn gas as well as oil. Gas is provided by Bay State Gas Company ("Bay State") during its off-peak summer season. The 23 MW combustion turbine was converted in 1983, and provided first-year savings in excess of the conversion cost. 10 DOMSC 252, 267. The 87 MW steam boiler conversion is in progress.

As a result of recent drops in the price of oil, the potential cost savings from burning gas instead of oil may be diminished or less certain than when the combustion turbine was converted. Thus, TMLP says it cannot determine at this time the economic risk to TMLP of the steam boiler conversion project. Supplement, pp. IV-7 to IV-8. Based on an agreement between TMLP and Bay State, Bay State will reimburse TMLP through discounted fuel prices for the estimated $1,275,000 cost of the conversion and $400,000 in additional electricity procurement expenses as a result of the boiler being out of service during construction. Information Response 12. However, the time period over which such reimbursement will be made has not been determined.

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[8] Under its long standing agreement with Montaup Electric Company, TMLP is entitled to that portion of Cleary 9 capacity needed to just meet TMLP's NEPOOL responsibility, each year, after other specified entitlements of TMLP are taken into account. Montaup purchases the remainder. The agreement expires when Montaup's cumulative annual purchases reach 25 percent of Cleary's expected life-of-unit capacity. See 10 DOMSC 252, 264.

Table 2

Existing Generating Facilities
Including Unit purchases
(1985)

Category	Station Name and Unit Numbers	Location	Winter Rating MW	Summer Rating MW	Type of Fuel	Ownership MW
Capability:						
Base Intermediate Fossil	Cleary No. 9	Taunton, MA	110	105	Oil Gas	35.7
Peaking Fossil	Cleary No. 8	Taunton, MA	25	25	Oil	25.0
Joint Ownership:						
Base-load Nuclear	Maine Yankee	Wiscasset, ME	830	814	Uranium	4.5
	Vermont	Vernon, VT	528	496	Uranium	2.4
Purchases:						Purchase MW
Base-Load Fossil	Canal No. 2	Sandwich, MA	584	580	Oil	10.0

Source: Supplement, P. V-42.

2. Sales of Excess Capacity

Under its contract with Montaup, TMLP can sell Cleary 9 capacity to Montaup only up to a total limit of 825 megawatt years, which is 25 per cent of the plant's net capability over its lifetime. After making annual sales of 60-65 MW in recent years, and in the current year 1985-86, TMLP will have only 17 MW of sales left on the contract in 1986-87, and none thereafter.[9] Information Response 15. Thus, new sales contracts for excess capacity are being sought by TMLP.

TMLP has stated that it has "an excellent improved market for Cleary 9 because it has made investments to improve the unit's availability and to enable it to burn gas as well as oil."[10] Supplement, P. IV-12.

TMLP has made a start in signing short-term and non-binding agreements with other municipal electric systems which, if renewed or exercised, would help absorb excess Cleary 9 capacity beyond 1985-86. These agreements, amounting to a potential 11 to 25 MW after 1988-89, are shown below:

TMLP's New Sales Agreements

System	Renewable Short-Term (MW)	Option For Life-of Unit (MW)
Braintree Electric Department	4 (thru 87-88)	12 (88-89 on)
North Attleboro Electric Department	2 (thru 87-88)	8 (88-89 on)
Massachusetts Municipal Wholesale Electric Co.	5 (indefinite)	

Source: Supplement, pp. IV-13 to IV-14.

TMLP has provided an analysis indicating that, were TMLP to make no sales in 1986-87 under new agreements such as those shown above (i.e., beyond the 17 MW of projected sales to Montaup and other normally expected power pool sales), the annual system revenue requirements from TMLP's customers in that year would be 12 percent higher than if the excess Cleary capacity were to be fully disposed of under such agreements. Document 4 provided at technical session. In later years, when sales to Montaup will have dropped to zero, the potential maximum impact on revenue requirements of any such failure to make sales under new agreements could be even greater.

The Siting Council finds that TMLP has taken appropriate steps to improve the attractiveness of Cleary 9 to utilities potentially seeking to purchase capacity. However, given that TMLP must replace, in each of the next few years, 40-55 MW of current capacity sales to Montaup, the Siting Council finds

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[9] See Footnote 8, supra.

[10] For a discussion of improvements, see Supplement, P. IV-3.

that the progress to date in signing agreements is limited and that the potential cost impacts, which may begin to affect ratepayers in a matter of months, are significant. Accordingly, the Siting Council intends to closely monitor TMLP's further progress in signing new agreements.

As a CONDITION for approval of its 1984 Supplement, TMLP shall provide to the Siting Council on or before December 15, 1986, a progress report on its efforts to sign new capacity sales agreements for Cleary 9. TMLP also shall provide a full update in its next filing.

C. Supply Diversification, Renewables and Cogeneration

TMLP historically has been highly dependent on oil. The gas conversion project has significantly modified TMLP's oil dependence, but only on a part-year basis. 10 DOMSC 252, 265 to 267. Assuming no use of gas at Cleary 9, as likely in the winter, TMLP was just over 90 percent dependent on oil for its capacity entitlements in 1985. See Table 2.

TMLP's participation in regional projects and its pursuit of other options to diversify supplies have been addressed in previous forecast reviews. See 10 DOMSC 252, 269-274. In summary, TMLP now receives over 3 MW of firm power from the Power Authority of the State of New York ("PASNY"). TMLP is also a participant in the Hydro Quebec transmission projects of which the first phase now is providing non-firm power and the second phase is planned to provide additional power including firm power in 1990. TMLP has pursued local projects involving coal and refuse burning, and capacity purchases involving nuclear and wood. TMLP has proceeded with a study of cogeneration potential in its service area, particularly as it may relate to the possible development of a district steam heating and cooling system. Supplement, pp. IV-27 to IV-43.

TMLP's recent efforts in the area of refuse burning and cogeneration are highlighted below.

1. Refuse Burning

Since the previous review, TMLP has culled and refined its local supply options involving refuse burning, alone or in conjunction with coal. Based on in-house review, TMLP has dropped two relatively large projects involving both fuels -- the Integrated Municipal Energy Resource System project, and the West Water Street Conversion project. Supplement, P. IV-30. TMLP says it now is pursuing through a consultant modular refuse-to-energy on a small 1 MW, 100 tons-per-day scale, with steam sales to the Commonwealth of Massachusetts Dever School. Supplement, P.IV-28. Meanwhile, TMLP is keeping open, but not pressing, the option of converting Cleary 9 to burn coal. Information Response 17.

The Siting Council previously has supported TMLP's pursuit of a waste-to-energy project, but questioned its ability to move ahead without a more regional project. 10 DOMSC 252, 273. TMLP believes it can implement a small project, apparently utilizing refuse from Taunton alone. However, TMLP acknowledges that project feasibility depends on sale of steam to the Dever School. Supplement, P. IV-28.

TMLP should continue to actively pursue regional possibilities for increasing the size of the project, in order to achieve greater supply diversification for TMLP and any economies of scale available in the context of a modular design. However, the Siting Council strongly supports the prospective achievement of multiple project benefits, which, in addition to supply diversification and fuel oil savings, include a direct environmental benefit for the Commonwealth by reducing the need to land fill trash.

2. Cogeneration and Independent Power Producers

Since the last filing, TMLP has engaged in a commercial/industrial customer survey and provided technical assistance to customers. In the survey TMLP identified 30 customers who either use steam now or have the potential to do so. The survey was conducted in part to determine the feasibility for a district steam heating and cooling circuit. Supplement, P. IV-34. However, TMLP was not able to report any specific implementation of cogeneration in its service area, whether related or unrelated to TMLP's technical research or consultation activities.

The Siting Council supports TMLP's pursuit of activities that are directly or indirectly related to fostering implementation of cost-effective cogeneration. However, the Siting Council placed a condition in its last decision requiring TMLP to "investigate methods to help bring about increased purchases of customer-owned generation." 10 DOMSC 252, 274. TMLP'S efforts were to include consideration of financial incentives and other ways to overcome obstacles to implementation of cost-effective customer-owned generation.

As a CONDITION for approval of its 1984 Supplement, TMLP shall provide in its next filing an update on plans of local customers to implement cogeneration, and a discussion, with recommendations, of alternative contractual and power-purchasing schemes (including pricing mechanisms) for encouraging economic purchases of customer-owned generation.

D. Conservation and Load Management

Since the last filing, TMLP has sponsored a cooperative effort with Mass Save, Inc. to facilitate low-cost installation of attic insulation for TMLP customers through a group bidding process. Supplement, P. IV-46. Although 42 attics have been insulated under the program, TMLP has not indicated any participation by its electric heat customers. Information Response 7. TMLP has no other ongoing or planned programs, beyond energy audits and informational activities, to help implement conservation and load management.

TMLP cites its efforts to promote conservation, through advertising and other informational methods, and even word of mouth. Supplement, P. IV-44 to IV-45. The Siting Council agrees that TMLP, as a publicly owned utility with a compact service area, likely does have the potential to be effective in promoting conservation through a variety of such mechanisms.

TMLP reports that it has implemented rate changes that charge more for peak use, and that it is considering a connection charge to discourage high penetration of low cost heat pumps. TMLP also indicated that it assisted Taunton High School and Reed & Barton with their analyses and negotiations regarding cogeneration, but did not report the extent of any actual implementation. Information Response 20.

With regard to customer implementation of conservation, TMLP does acknowledge that "for many customers, even a relatively short payback of 2 to 3 years on a relatively safe investment may still not be an adequate financial incentive." TMLP's response is that it is considering programs that would "front-end" the investment cost, but provide for total pay back to the utility from the customer's energy savings. Supplement, P. IV-48 to IV-49.

The Siting Council encourages TMLP to proceed with implementation of programs to facilitate implementation of cost-effective conservation and load management.

However, in its previous decision, the Siting Council ordered TMLP to demonstrate its consideration of conservation and load management strategies as part of an integrated supply planning approach. The Siting Council deemed this approach necessary to enable TMLP to determine the maximum extent to which conservation and load management could and should be implemented as part of a least-cost supply plan. The Siting Council also ordered TMLP to report on its progress and/or plans regarding appliance use surveys.[11]

TMLP has stated that it will be obtaining models that better quantify economic demand strategies. Information Response 11. While the Siting Council supports this step, it is concerned that TMLP has cited its excess-capacity situation as a reason for not aggressively pursuing all related analyses, particularly development of load management strategies and implementation of residential appliance use surveys. Information Responses 9 and 10.

The Siting Council finds that TMLP's excess-capacity situation is not an excuse for delay, in developing cost-effective demand-side strategies and related analytical tools. Development of such capabilities requires lead time. Until TMLP has the ability to analyze what is possible within its service territory and what, if any, strategies could reduce system costs even in light of excess capacity, TMLP will not know whether it is planning for and actually providing a least-cost power supply to its customers. Accordingly, the Siting Council reinstates the condition from the previous decision.

As a CONDITION for approval of its 1984 Supplement, TMLP is required to report in its next filing on its progress and/or plans regarding appliance-use surveys, and is required to demonstrate its consideration of conservation and load management strategies as part of an integrated supply planning approach in all of its future filings.

E. Supply Planning Process

TMLP is developing a strategic power supply planning model aimed at integrating demand forecasting and supply planning. TMLP has begun to apply

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[11] Although beneficial for incorporating the most accurate data possible, such surveys are not a prerequisite for initial demonstration of an integrated analysis.

the model, and TMLP states that the object of its strategic power supply planning efforts to date has been to determine the most diverse and economical power supply currently available to TMLP. Supplement, P. IV-22.

In its applications of the model, TMLP thus far has focused on capacity expansion, system generation and revenue requirements submodels. These submodels select the least cost power supply configuration, based on net present value calculations and use of monthly load duration curves to approximate the operation of TMLP's annual supply resources. Any costs of incurring power shortfalls (i.e., for NEPOOL outage services) also can be reflected. TMLP has used the model to analyze sales of excess Cleary 9 capacity, conversion of Cleary 9 to burn gas as well as oil, conversion of Cleary 9 to coal, and various new supply options. Supplement, P. IV-23 to IV-24.

TMLP indicates that it will be obtaining sub-models and, as necessary, appropriate end use data to better quantify demand strategies. TMLP believes that, in theory, demand side resources can be modeled, but that "the reality of modeling these resources is difficult." Information Response 11.

The Siting Council approves the direction TMLP is taking with respect to strategic planning models, and the progress to date in applying such models, as appropriate for a utility of TMLP's size and circumstances. Because of the significant lead times required for development and application of necessary capabilities, the Siting Council believes TMLP should now actively pursue the integration of demand side strategies into its planning approach, and not wait for the current excess-capacity situation to be resolved. See Section D, supra.

V. DECISION AND ORDER

The Siting Council hereby APPROVES the 1984 Forecast Supplement of Taunton Municipal Lighting Plant subject to the following conditions:

1. TMLP shall provide in its next filing an analysis which compares, by residential rate class in 1986, average full-year usage levels of new customers connected in 1985 with old customers connected prior to 1985. TMLP also shall report and discuss the forecasting implications of the relative rates of change over the base period for service-area population, total residential customers and base-class customers.

2. TMLP shall provide in its next filing compilations of annual industrial sales by SIC code for all available years from 1984 through 1986, discuss implications of sectoral trends for its forecasting in general, and report as appropriate on its consideration of specific modeling changes to better capture sectoral growth patterns.

3. TMLP shall provide on or before December 15, 1986, a progress report on its efforts to sign new capacity sales agreements for Cleary 9. TMLP also shall provide a full update in its next filing.

4. TMLP shall provide in its next filing an update on plans of local customers to implement cogeneration, and a discussion, with

recommendations, of alternative contractual or power purchasing schemes (including pricing mechanisms) for encouraging economic purchases of customer-owned generation.

5. TMLP is required to report in its next filing on its progress and/or plans regarding appliance-use surveys and is required to demonstrate its consideration of conservation and load management strategies as part of an integrated supply planning approach in all of its future filings.

The next forecast will be due on April 1, 1987.

Energy Facilities Siting Council

By Robert D. Shapiro
Robert D. Shapiro
Hearing Officer

Boston, October 21, 1986

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council by the members and designees present and voting: Sharon M. Pollard, (Secretary of Energy Resources); Sarah Wald (for Paul W. Gold, Secretary of Consumer Affairs); Joellen D'Esti (for Joseph D. Alviani, Secretary of Economic and Manpower Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Stephen Umans (Public Electricity Member); Madeline Varitimos (Public Environmental Member); Joseph W. Joyce (Public Labor Member). Ineligible to vote: Dennis LaCroix (Public Gas Member). Absent: Elliot J. Roseman (Public Oil Member).

Sharon M. Pollard
Sharon M. Pollard
Chairperson

3 November 1986
Date

COMMONWEALTH OF MASSACHUSETTS

Energy Facilities Siting Council

In the Matter of the Petition of Cambridge Electric Light Company for Approval of its Occasional Supplement to its Second Long-Range Forecast of Electric Power Needs and Requirements	)	EFSC No. 83-4A

FINAL DECISION

Robert D. Shapiro
Hearing Officer

On the Decision:
Steven E. Oltmanns

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The Energy Facilities Siting Council ("Siting Council") hereby conditionally APPROVES the Petition of Cambridge Electric Light Company ("the Company" or "CELCo") to construct an underground 115 kilovolt ("kv") transmission line beginning at the Company's Alewife Substation and terminating on Putnam Avenue, and to construct a 115 kv/13.8 kv substation ("Proposed Substation" or "Putnam Station") on Putnam Avenue in the City of Cambridge ("Cambridge" or "the City").

I. INTRODUCTION AND HISTORY OF THE PROCEEDINGS

A. Overview

Cambridge Electric Light Company is an electric utility engaged in the production, sale and distribution of electric energy at retail to approximately 39,000 customers in Cambridge, Massachusetts. CELCo also sells power to the Town of Belmont, and steam from its electric generating stations at wholesale to COM/Energy Steam Company, an affiliated company.

In 1985 the Company experienced a summer peak demand of 216 megawatts ("Mw") and sold a total of 1,070,179 megawatt-hours ("Mwh") (excluding sales at wholesale to the Town of Belmont). The Company's 1986 long-range forecast projects that by 1995 its peak demand will be 308 Mw (Exh. HO-N-27(c)). The Company's sources of electric power are its own generating stations, located in the City of Cambridge, and purchased power wheeled into the city via transmission lines owned by Boston Edison Company ("Boston Edison" or "BECo"). Purchased power is received by the Company at three interconnection points with Boston Edison: Blackstone Substation, Prospect Substation, and Alewife

Substation.

The Company is a party to an agreement ("the Agreement") with Boston Edison which provides for the availability and support of various facilities at Boston Edison's Brighton Substation which ties into the Company's 13.8 kv system at Blackstone Substation. This provides approximately 55 megavolt-amperes ("MVA") of transmission capacity to the CELCo system (Exh. HO-1, p. 2).

The Company was notified by Boston Edison on May 18, 1981, that BECo intended to implement the termination provision of the Agreement and that service would not be provided from the Brighton Substation after June 1, 1985 (Exh. HO-1, p. 2). This date has since been extended to May, 1987 (Exh. HO-2, p. 2). Brighton Substation is the primary feed for wheeling power into the commercial and industrial (Blackstone/Kendall) area of Cambridge. The Company alleges that without this service, its system will be unable to supply peak demands under single contingency conditions experienced at the time of peak load (Exh. HO-N-3).

With this filing, the Company requests the Siting Council's approval to construct an underground 115 kv transmission line approximately four miles in length beginning at Alewife Substation and terminating on Putnam Avenue, and a 115 kv/13.8 kv substation at the Putnam Avenue end of that transmission line. The proposed route for this transmission line would extend under public streets in Cambridge.

B. History of the Proceedings

On June 30, 1983, CELCo filed with the Siting Council the Company's Occasional Supplement to the April 1, 1982 Long-Range

Electric Forecast ("Occasional Supplement") which included its proposal for construction of a 115/13.8 kv substation on Putnam Avenue and a four-mile 115 kv underground transmission line along Memorial Drive and the Charles River (hereinafter referred to as "Memorial Drive/River Route") to connect the proposed substation to Alewife Substation (Exh. HO-1).

After due notice, on September 20, 1983, the Siting Council and the Department of Public Utilities ("DPU") conducted a joint public hearing in Cambridge. The Siting Council and the DPU conducted a pre-hearing conference on September 21, 1983.[1]

On December 6, 1983, the Hearing Officer issued a Procedural Order granting the petitions to intervene of the City of Cambridge; petitioners Anninger, Martha and Paul Lawrence, Brode, Vickery, Wheeler and Lowery as individuals and as representatives of the Neighborhood Ten Association ("Neighborhood Ten"); petitioners Santoro, Shatz, Warren, and Turrell as individuals and as representatives of the Putnam and Western Avenue Tenants Association ("PWATA"); Francis Hagerty; Dr. A.K. Solomon; and Don K. Price.

On December 19, 1983, the Siting Council conducted a second pre-hearing conference to discuss the discovery schedule. On January 5, 1984, the Hearing Officer issued a Procedural Order requiring the Company to provide a written report of its interactions with relevant government agencies and other interested parties concerning the proposed transmission line. The Company submitted that report on

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[1] Although the Siting Council and the DPU agreed to jointly conduct the public hearing and first pre-hearing conference, each agency has the authority to render an independent decision pursuant to its particular statutory authority.

January 11, 1984.

On April 2, 1984, the Siting Council conducted an informal technical session for the purpose of discussing the Company's transmission and distribution systems.

On April 24, 1984, Neighborhood Ten requested that the Hearing Officer take measures to bring Boston Edison into the proceeding as "an active party or as an informal participant" in order to provide information that Neighborhood Ten deemed essential for a determination of need. On May 2, 1984, PWATA joined Neighborhood Ten in this request. On May 24, 1984, the Hearing Officer informed Neighborhood Ten and PWATA that it planned no immediate action regarding the involvement of Boston Edison in the proceeding.

On May 22, 1984, the Siting Council conducted an informal meeting to discuss possible alternatives to the Company's proposed Memorial Drive/River Route. On July 9, 1984, CELCo informed the Siting Council that, as a result of the May 22 meeting, the Company was pursuing its investigation of alternative routes. On August 15, 1985, the Company filed Amendment No. 1 to its June 30, 1983 Occasional Supplement, designating a new route, hereinafter known as the "City Streets Route," as its primary alternate route, and another new route, hereinafter referred to as the "River Crossing Route" as its secondary alternate route (Exh. HO-2).

After due notice, on January 21, 1986, the Siting Council conducted a public hearing in Cambridge regarding the Company's amended proposal for construction of the transmission line. The notice of public hearing invited new parties to file petitions to intervene. At the same time, the Hearing Officer required all existing intervenors to file a letter indicating their desire to continue as an intervenor in the proceeding.

On April 2, 1986, the Hearing Officer issued a Procedural Order granting the petitions to intervene of Harvard College ("Harvard"); the Massachusetts Institute of Technology ("MIT"); and the Metropolitan District Commission ("MDC"). At the same time, the Hearing Officer noted that Francis Hagerty had not requested continuation of his intervention, and Charles W. Hare had replaced Don Price as an intervenor. All other intervenors requested to remain in the proceeding.

The Siting Council conducted a third pre-hearing conference on April 15, 1986, to discuss the discovery and hearing schedule (Exh. HO-3). At the pre-hearing conference, the Company submitted an amendment to its facilities proposal, designating the City Streets Route as its proposed route (Exh. HO-4). The Company did not designate an alternate route.

On July 11, 1986, the request of Charles W. Hare to withdraw as an intervenor was granted. On August 29, 1986, the Hearing Officer granted Harvard's request to withdraw as an intervenor.

On August 28, 1986, the Hearing Officer submitted certain information requests to Boston Edison in response to BECo's agreement to respond to such requests (Exh. HO-6).

On September 22, 1986, the Siting Council conducted a fourth pre-hearing conference to discuss a revised discovery and hearing schedule. At this conference, the Hearing Officer also ordered the Company to file a letter designating its alternate route for the transmission line, as well as primary and alternate sites for its proposed substation (Exh. HO-7).

On September 25, 1986, the Company submitted a letter reaffirming the City Streets Route as its proposed route and designating the Poleyard as the proposed site for the proposed substation (Exh. HO-8).

On October 16, 1986, the Company submitted a letter designating the corner of Putnam and Western Avenue as its alternate substation site, describing said site as an "undesired and nominal alternative." At the same time, the Company designated the River Crossing Route as its alternate transmission line route (Exh. HO-10).

The Siting Council staff conducted an evidentiary hearing on November 24, 1986. The Company presented four witnesses at the hearing: Beauford L. Hunt, Supervisor of Facilities Planning; Robert L. Fratto, Manager of Demand Planning and Forecasting; Harold W. Eklund, Chief Electrical Engineer; and W. Stephen Collings, Environmental Engineer. The Hearing Officer entered 97 exhibits in the record, largely composed of the Company's responses to information and record requests.

II. STANDARD OF THE REVIEW

Before it can approve an application to construct facilities under its jurisdiction, the Siting Council must find that the proposed construction is consistent 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. In so doing, the Siting Council determines whether plans for construction of an applicant's proposed facilities are "...based on substantially accurate historical information and reasonable statistical projection methods." G. L. c. 164, sec. 69J.

The Siting Council requires applicants to justify facility construction in two phases. First, the applicant must show that facilities are needed. For an electric transmission system proposal, the Siting Council has found that the inability of the existing system to withstand the loss of any single major component is sufficient to justify the need for facilities to maintain reliability. In Re Hingham Municipal Lighting Plant, 14 DOMSC 7, 12 (1986); Boston Edison Company, 13 DOMSC 63, 67 (1985); Taunton Municipal Light Plant, 8 DOMSC 148, 154 (1982); Commonwealth Electric Company, 6 DOMSC 33, 44-47 (1981). Alternatively, the Siting Council might base its determination of need on other considerations, such as forecasted reliability problems associated with load growth or a balance of cost advantage versus environmental impact. Massachusetts Electric Company et al., 13 DOMSC 119, 133 and 188 (1985); Boston Gas Company, 11 DOMSC 159, 163 (1984).

Second, the applicant must show that the proposed construction plan is superior to the alternatives in satisfying the identified need. The applicant must demonstrate that it has identified a reasonable range of practical alternatives, including non-construction alternatives, and evaluated all of the options on an equal basis. The proposal and alternatives are compared on the basis of the environmental impacts and costs of maintaining a secure and adequate power source, all of which must be consistent with the Siting Council's statutory mandate. In Re Hingham Municipal Lighting Plant, 14 DOMSC 7, 12; Massachusetts Electric Company et al., 13 DOMSC 119, 133, 188 (1985); Boston Edison Company 13 DOMSC 63, 67, 68 (1985).

III. REVIEW OF THE NEED FOR THE PROPOSED FACILITIES

A. Description of the Existing System

Figure 1 shows the existing CELCo system facilities, including generating stations, substations, and transmission lines. The Company provides power through its own generation and through power wheeled into Cambridge via BECo transmission lines.

The Company's system is split into two electrically independent load areas, as shown in Figure 2. The Company refers to the southeast area as "the South Island," and the remainder of the City as "the North Island" (Exh. HO-N-3, p. 10).

The Company owns and operates two generating stations, Kendall Station ("Kendall") and Blackstone Station ("Blackstone") (Exh. HO-5). Power which is wheeled into the City of Cambridge from Boston Edison enters the CELCo system at three interconnection points: (1) from Brighton Substation, 55 Mw of capacity is imported at Blackstone Substation; (2) from Somerville, 84 Mw of capacity is imported at Prospect Substation; and (3) from Boston Edison Substation No. 509 located in the North Island, 50 Mw of capacity is imported at Alewife Substation (Tr. 29).

All four of the Company-owned substations (Alewife,[2] Blackstone, Kendall, and Prospect) operate at 13.8 kv. This is consistent with the existing CELCo transmission system, which also operates at 13.8 kv. The Company is currently in the process of

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[2] The CELCo owned portion of BECo's North Cambridge Substation is known as Alewife Substation.

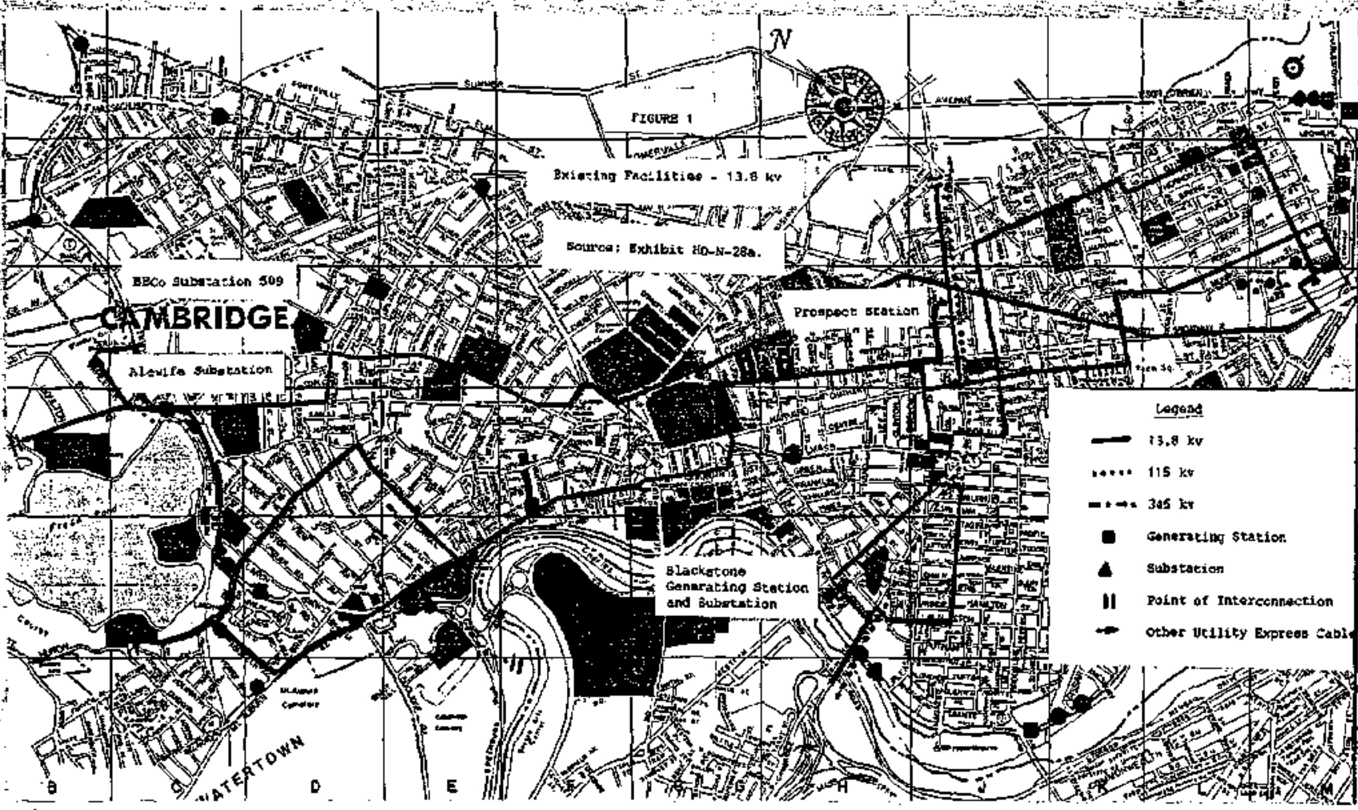
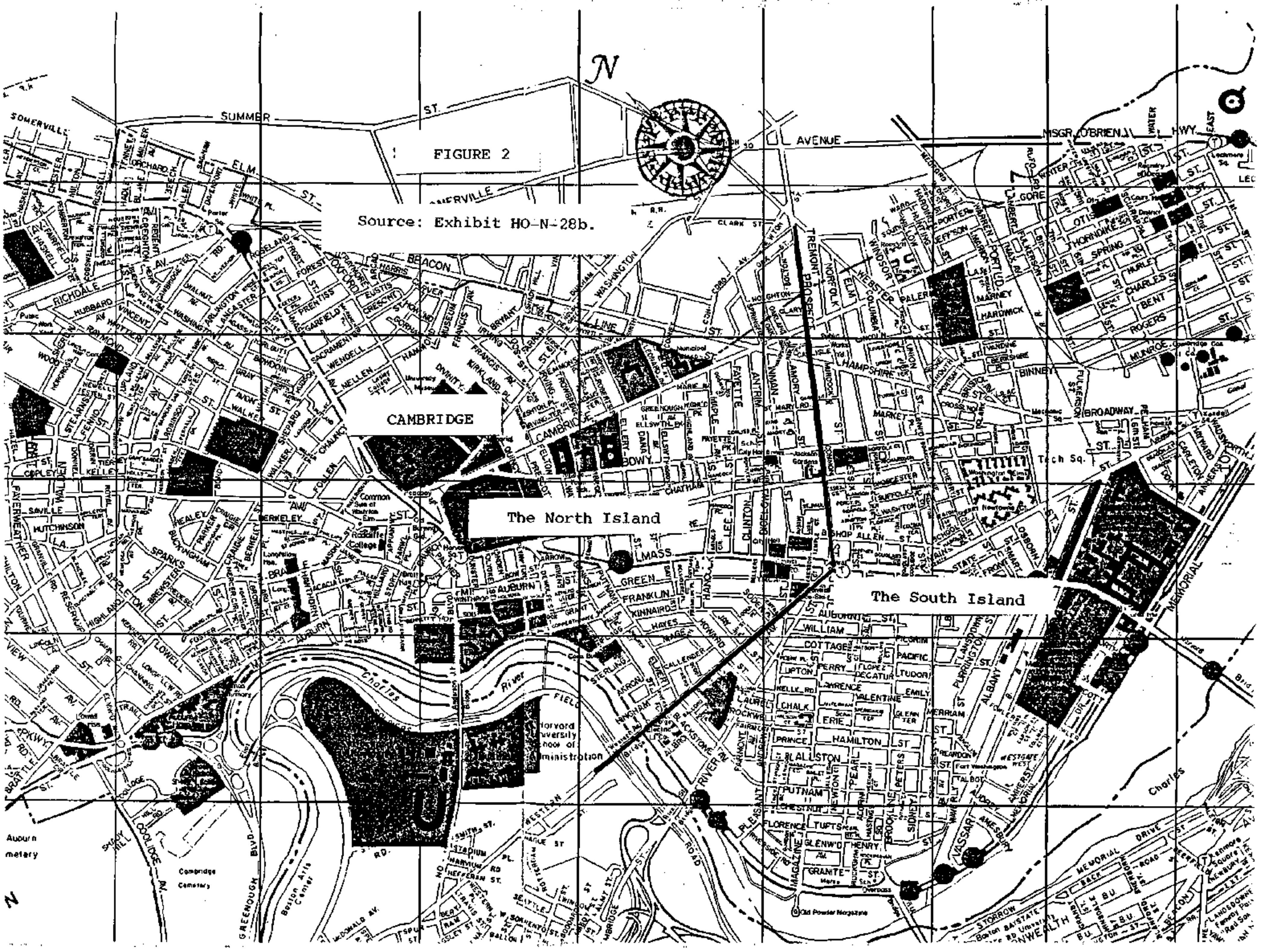

N
FIGURE 1
Existing Facilities - 13.8 kv
Source: Exhibit HO-N-28a.
BECo Substation 509
CAMBRIDGE
Alewife Substation
Prospect Station
Blackstone
Generating Station
and Substation
WATERTOWN
Legend
13.8 kv
115 kv
345 kv
Generating Station
Substation
Point of Interconnection
Other Utility Express Cabl

FIGURE 2

Source: Exhibit HO-N-28b.



installing a second transformer at Alewife Substation, to provide support for the existing transformer at that substation. Installation of this second transformer at Alewife, planned to be completed in 1987, will bring the normal capacity of the CELCo system to 348 Mw (Exh. C-1-2).

Also illustrated on Figure 1 are facilities in Cambridge which are not owned by the Company. Boston Edison maintains two 115 kv transmission lines, each consisting of two cables, which run through the City of Cambridge, and 115 kv substation, Boston Edison Substation No. 509. Also in the City, Boston Edison owns a 345 kv transmission line, consisting of two cables, running from its Substation No. 509 to its Substation Nos. 211 and 250 (not shown) (Exh. HO-1, p. 26).

B. Adequacy of the Existing System

The Company asserts that new facilities are needed because its existing facilities will be inadequate to ensure a reliable supply of power to the South Island of the system in the absence of interconnection with BECo's Brighton Substation. BECo has informed the Company that the Brighton interconnection will not be providing service to the Company beyond May, 1987. The Company notes that without the Brighton interconnection, the power normally taken over these cables must enter the system at either Alewife Substation or through Somerville Substation. The Company claims that these interconnections would reach their thermal limits at peak load conditions because of the heavy power flow, even though all existing internal generation is on line. CELCo argues that if all generators are operating at maximum output, further control of power flow on the

Alewife and Somerville interconnections is only achievable by load shedding[3] (Tr. 31).

The Company identifies several single contingency situations which would cause equipment overload and voltage degradation without disconnection of major load sources. In addition, the Company indicates that based on its latest forecast of peak load growth, even if the Brighton Substation remained interconnected, CELCo would be unable to meet total connected load as early as 1991 in the event of a 50 Mw single contingency (Exh. HO-N-8).

The Company provides reliability standards for evaluating the adequacy of its transmission system; describes its methods and assumptions for calculating loadings on individual system elements; and attempts to show that, in several instances, the loadings calculated for several system elements exceed the capacity limits dictated by the Company's reliability standards.

In regard to reliability standards, the Company presents the "Reliability Standards for the New England Power Pool" ("NEPOOL Standards") and the "Basic Criteria for Design and Operation of Interconnected Power Systems" of the Northeast Power Coordinating Council ("NPCC Standards") (Exh. HO-N-1(b)). Both the NEPOOL and NPCC Standards require that all equipment operate within normal capacity limits when there is no contingency and within emergency limits following any reasonably expected contingency.[4] These standards

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3 "Load shedding" is defined as the reduction of system demands by systematically, interrupting in a predetermined sequence, the load flow to major customers and/or distribution circuits, normally in response to system or area capacity shortages or voltage control considerations.

4 "Normal" and "emergency" limits refer to the maximum (continued)

also require that transmission systems be designed so that loss of critical system elements will not adversely affect the stability of the system.[5] In addition, the Company requires all transmission system voltages be within plus and minus five percent of the nominal 13.8 kv level to provide voltage to customer equipment which falls within the accepted standard range designed for the equipment by the manufacturers. In actual practice, CELCo states that the voltage on its system is controlled within a much tighter tolerance than plus and minus five percent. The Company notes that typically, the voltage variation on the system is closer to plus and minus two or three percent (Exh. HO-N-2).

The Siting Council consistently has found that transmission systems should have line loadings that are within normal ratings under normal conditions and within emergency ratings after a contingency. In addition, the Siting Council concurs that the CELCo system should be able to maintain its stability and its required voltage levels in the event of a contingency. Failure of the system to meet these standards might be reasonable proof that the existing system is

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(footnote continued)
amount of power (in MVA) that a transmission line can carry under normal and emergency conditions. A transmission line that is loaded beyond its capacity limits can suffer permanent physical damage, shortened life expectancy and increased probability of failure in service. A "disturbance" or "contingency" might be the loss of service of a major system element, such as a major transmission line, transformer, or generating unit. In Re Boston Edison Company, 13 DOMSC 63, 70 (1985).

5 "Stability" refers to the ability of an alternating current ("AC") power system to maintain its integrity following a disturbance. The possible consequences of instability include permanent damage to generators and widespread loss of electrical service to customers for a long period of time. In Re Boston Edison Company, 13 DOMSC 63, 70 (1985).

inadequate. In Re Boston Edison Company, 13 DOMSC 63, 70 (1985).

To calculate loadings on individual system elements, CELCo uses the technique known as "load flow analysis." This analysis requires the Company to determine voltages at certain key points in the system and loadings on specific transmission lines and transformers, under pre-specified conditions. The Company compares these voltages and line loadings with equipment ratings to determine if reliability standards are being violated. The pre-specified conditions include assumptions as to the level of system demand; the distribution of demand among various points in the system; the amount of power provided by individual generating units; the operating characteristics of relevant transmission lines and transformers; and the configuration of relevant transmission lines, transformers, generators, demand nodes, and breakers. A full analysis also requires specification of the contingencies that the system should be able to withstand. (Tr. 40, 41).

"Exposure hour analysis" was done as part of the Company's load flow analysis. Such an analysis reveals the percentage of time during which the occurence of contingencies would require a response (e.g., load shedding) to insure system reliability. The results are a function of the load level at which the outage occurs and the number of hours which the load level is expected to equal or exceed the level of capacity remaining on the system to serve load (Exh. HO-N-8).

The load flow analyses conducted by the Company were performed in the following manner. First, the contingencies were analyzed at the projected 1986 peak load level of 259 Mw, assuming the Brighton interconnection in service. Next, the analyses were conducted assuming the Brighton interconnection in service as well as the addition of a second transformer which the Company expects to have installed at Alewife Station in 1987, assuming a projected peak load level of 267 MW for that year. Third, CELCo analyzed load flows in 1991 assuming the second Alewife transformer in service and the Brighton interconnection still available at a peak load level of 287 MW for that year. Finally, the Company repeated this analysis for 1991, except that the Brighton interconnection was not assumed to operate, so as to reflect the system configuration after the Company loses this service (Exh. HO-N-5(a), HO-N-5(b), HO-N-6(a), HO-N-6(b), HO-N-10(a), and HO-N-10(b)).

In its load flow analysis and exposure hour analysis, the Company used the 1985 long-range peak load forecast as presented in Table 1 (Exh. HO-N-27(b)). The peak load forecast is provided in a bandwidth format, illustrated in Table 1 (Exh. HO-N-27(b)). Confidence intervals at the 90 percent and 95 percent level define boundaries of several possible escalation rates from 1985 through 2015. CELCo used a base case demand forecast and the upper 95 percent bound for facility planning so that system planners are 95 percent confident that the system peak demand will fall within the upper and lower bounds. Since installed facilities must be designed to meet actual peak demand in future years, CELCo plans its facilities against a 95 percent bound of the forecast which includes a reserve margin (Exh. HO-N-3, p. 11).

The Company's 1986 long-range peak load forecast exceeds the values in its 1985 forecast (Exh. HO-N-27(c)). The Company's demand forecast methodology was unconditionally approved in 1984, In Re Commonwealth Electric Company, 12 DOMSC 39, 50 (1985), and in 1986 In Re Commonwealth Electric Company, 15 DOMSC __, __ (1986). For the

TABLE 1

CELCo 1985 Long-Range Load Forecast

Summer Peak Load (MW)

Year	Upper Bound 95%	Upper Bound 90%	Base Case	Lower Bound 90%	Lower Bound 95%
1985	243	241	230	219	217
1986	259	256	244	233	230
1987	267	264	251	239	236
1988	271	269	255	242	239
1989	277	274	260	246	243
1990	283	279	264	250	246
1991	287	284	268	253	250
1992	291	288	271	255	252
1993	296	292	275	258	254
1994	300	296	277	259	255
1995	302	298	279	261	257
1996	304	300	281	263	258
1997	306	301	282	264	259
1998	308	304	284	265	261
1999	310	306	286	267	262
2000	312	307	287	267	263
2001	316	311	290	270	266
2002	320	315	293	273	269
2003	324	319	297	276	272
2004	328	323	301	279	275
2005	332	327	305	282	278
2006	336	331	309	285	281
2007	341	335	313	288	284
2008	346	339	317	291	287
2009	351	343	321	294	290
2010	356	348	325	297	293
2011	361	353	329	300	296
2012	366	358	333	303	299
2013	371	363	337	306	302
2014	376	368	341	309	305
2015	381	373	345	312	308
Compound Annual Growth Rate	1.51%	1.47%	1.36%	1.19%	1.17%

purposes of this proceeding, the Siting Council accepts the Company's 1986 peak load forecast.

In several recent facilities cases, the Siting Council has accepted load flow analysis as a reasonable calculation method. In Re Massachusetts Electric Company et al., 13 DOMSC 119, 133 and 189 (1985); Boston Edison Company, 13 DOMSC 63, 71 (1985); Boston Edison Company, 3 DOMSC 81 (1979). In these cases, however, the Siting Council has carefully reviewed the assumptions used by Companies in these analyses. In this case, the Siting Council finds that the use of load flow analysis is appropriate, but reviews the Company's input assumptions, including the record of actual occurrences of the conditions that are used to show the need for the line. The various contingencies explored by the Company are described in detail below.

1) Loss of Alewife Transformer

The first contingency addressed by the Company is the loss of the transformer at Alewife Substation, assuming that the Brighton interconnection remains in service. This is the largest single contingency which the Company plans for and would result in a loss of 50 Mw of capacity. At a peak load of 259 Mw (a condition expected to occur during 17 hours in 1986 [6]), load shedding would be required if the Alewife transformer were out of service. The Company's concern here revolves around the thermal limits on the transmission lines from the Prospect Bulk Substation to North Cambridge Substation, and the

[6] The period of time at which the Company expects to shed load under specific circumstances is a statistical determination and not necessarily a continuous period of time.

Somerville transformers. Power flow through the two Somerville transformers exceeds normal operating limits even with 23 Mw of load shedding (Exh. HO-N-5(a)). Under this circumstance, the Company would be forced to shed 23 Mw of load from Prospect Bulk and Alewife Substations during 17 hours to reduce flow through Somerville transformers (Exh. HO-N-5(a) and HO-N-8).

In 1987, the Company expects to complete installation of a second transformer to the 115 kv bus at Alewife Substation. According to the Company's load flow analysis, the addition of the second transformer postpones the estimated need to shed load until 1991, provided that the Brighton interconnection is still in service, since CELCo could use internal generation to support the system so that the Somerville lines operate within normal limits (Exh. HO-N-6(a) and HO-N-8).

But in 1991, with the second transformer at Alewife Substation and the Brighton interconnection still in service, the Company alleges that failure of an Alewife transformer would cause overloading on the Prospect Bulk to Alewife Substation tie lines as the Prospect Bulk source took on some of the load (Exh. HO-N-10(a)). One Mw of load shedding would be required for a period of two hours (Exh. HO-N-8).

With the loss of the Brighton interconnection in 1991, loss of a tranformer at Alewife Substation would place increased load on the remaining transformer and CELCo would approach the operational limit at Somerville Station. System-wide load shedding would be required. By disconnecting 41 Mw of load during an expected ninety-two hours, the system would be allowed to function but overloads would remain on the Somerville Substation and transmission lines (Exh. HO-N-10(b) and HO-N-8).

CELCo reports that it actually experienced loss of the Alewife transformer on June 23, 1982. Since the system load was 140 Mw and there was sufficient generating capacity available within the City, no major load shedding was required, although there was a temporary loss of load before switching to alternate sources (20 Mw for approximately thirty-five minutes) (Exh. HO-N-7(a)). Accordingly, the Siting Council finds that the loss of the Alewife transformer is a reasonable contingency to consider when determining the adequacy of the Company's existing facilities.

2) Loss of Prospect Bulk Bus and Two Tie Lines

The Company states that under a situation where CELCo lost the Prospect Bulk Bus and two tie lines, load shedding would be required to protect the two transmission lines between the Prospect Bulk bus and the Somerville Substation. At and above 94 percent of peak load (a situation that occured during ten hours in 1986), 16 Mw of load shedding would be required for a ten hour period from feeder busses at Prospect Substation to reduce the power flow on the remaining two Somerville tie lines to within emergency limits (Exh. HO-N-5(a) and HO-N-8).

The Company states that in 1987, with the second transformer at Alewife Substation, loss of two of the Somerville tie lines would still place a burden upon the remaining two tie lines, but no load disconnection would be required and voltage levels would remain within normal limits (Exh. HO-N-6(a) and HO-N-8).

The Company states that in 1991, with both the Brighton interconnection and the second transformer at Alewife Substation in service, loss of Prospect Bulk Substation bus with two tie lines would cause the remaining two Somerville Substation tie lines to be at their emergency rating, but still no load shedding would be required, and normal voltages could be maintained by adjusting the voltage at Brighton Substation (Exh. HO-N-10(a) and HO-N-8).

The Company states that after the Brighton interconnection is expected to terminate in 1991, loss of the Prospect Bulk bus with two tie lines would cause overloading on the remaining tie lines between Somerville and Prospect Bulk Substations. To control flow on these two lines, one transformer at Somerville Substation would need to be disconnected in order to increase power flow into the system from Alewife Substation. All internal generation would be required to be on line, and 26 MW of load shedding from Prospect Bulk Substation with an additional 20 MW of load shedding systemwide for a 132 hour period would be required to maintain normal operating limits on the Somerville tie lines (Tr. 32; Exh. HO-N-10(b) and HO-N-8).

Although this contingency has never occurred, the Company states that the possible loss of the Prospect Bulk bus must be examined because of the magnitude of capacity that would be lost and the length of time required to restore those facilities to normal (Exh. HO-N-7(a)). Accordingly, the Siting Council finds that loss of the Prospect Bulk Substation and two tie lines is a reasonable contingency that must be considered in order to determine whether the Company's existing facilities are adequate.

3) Loss of Kendall Station Unit 3

CELCo's load flow analysis indicates that loss of Kendall Station

Unit 3 in 1986 at peak load conditions of 259 Mw would not result in any loss of load (Exh. HO-N-8).

The Company states that with the installation of the second transformer at Alewife Substation in 1987, loss of Kendall Station Unit 3 would still not be cause for load shedding at the forecasted peak load of 267 Mw (Exh. HO-N-8 and HO-N-6(a)).

CELCo estimates that in 1991, assuming both the second Alewife transformer and the Brighton interconnection in service, failure of Kendall Station Unit 3 would reduce the ability to control power flow on the Brighton tie lines but load shedding could be avoided by pushing the remaining Kendall Station jets to the maximum capability (Exh. HO-N-10(a) and HO-N-8).

According to the Company, without the Brighton interconnection in 1991, the loss of Unit 3 would prevent the Company from controlling tie line flows, resulting in overload of facilities at Somerville Substation. Load shedding of 20 Mw at Kendall Substation and 10 Mw at Prospect Bulk Substation would be the minimum required for thirty-three hours to reduce the flow to within operating limits at Somerville Substation (Exh. HO-N-10(b) and HO-N-8).

The Company has reported eighteen outages of Kendall Station Unit 3 since 1976. In each case, no load shedding was required. The following is a list of the forced outages of Unit 3 since 1976 (Exh. HO-N-7(a)):

Kendall Station Unit 3 Forced Outages

	Date		Duration	Cause of Outage
1976	September	1	24 Hours	Repair Steam Line Flange
1978	February	2	24 Hours	Boiler Tube Repair
1978	August	29	24 Hours	Repair Condenser Leak
1979	January	21	96 Hours	Repair Boiler Tube Leak
1979	January	26	48 Hours	Repair Boiler Tube Leak
1980	May	13	9282 Hours*	Major Generator Field Repairs
1981	July	11	24 Hours	Repair Condenser Leak
1981	July	17	24 Hours	Repair Turbine Steam Valve
1981	October	30	24 Hours	Repair Boiler Fuel Oil Valve
1981	November	24	24 Hours	Turbine Balance Move
1983	March	14	24 Hours	Rotor Inspection
1983	October	1	48 Hours	Repair Desuperheater
1983	December	12	18 Hours	Repair Turbine Governor
1984	January	12	29 Hours	Repair Exciter
1984	February	10	3 Hours	Repair Main Breaker
1984	April	13	8 Hours	Repair Exciter
1985	January	15	59 Hours	Repair Throttle Valve
1985	July	19	5 Hours	Vibration Problem

* Kendall Station Unit 3 was forced out of service from May 13, 1980 (5549 hours in 1980) until June 4, 1981 (3733 hours in 1981), for a total outage of 9282 hours.

The Siting Council notes that without the Brighton interconnection in 1991, load shedding would be required if Unit 3 went out of service. Accordingly, the Siting Council finds that the loss of Kendall Station Unit 3 is a reasonable contingency to considered in determining whether the Company's existing facilities are adequate.

4) Summary

The Siting Council finds that the Company's assumptions in analyzing contingencies and conducting load flow analyses are reasonable because they are based on accurate historical information and an approved demand forecasting methodology. The information provided by the Company indicates that if the projected levels of load are considered in conjunction with contingencies and generation conditions which have occurred in the past and reasonably could occur in the future, unacceptable transmission system conditions would result. Accordingly, the Siting Council finds that the Company's existing facilities are inadequate to ensure a reliable supply of power to the North and South Islands of the Company's system in the future.

C. Alternatives

1) Non-construction Alternatives

The Company has indicated that 23 Mw of load shedding may be required with the largest single contingency in 1986. Thus, to solve the reliability problems cited above, a non-construction alternative would have to account for load reductions of at least 23 Mw in 1986. In 1991 without the Brighton interconnection in service, as CELCo expects, the largest single contingency would require a total of 46 MW of load shedding, so a non-construction alternative would have to account for load losses of 46 Mw by 1991.

To explore the viability of a non-construction solution to the reliability problems, the Company evaluated the potential of load management to deliver sufficient levels of load reductions within the required lead times identified in these contingency analyses.

Although specific end-use data necessary to support an independent load management analysis for the City of Cambridge were not available, CELCo based its estimates of load management potential on a similar estimate for Commonwealth Electric Company. The Company states that relative to load growth over the time period from 1986 to 1995, the amount of gross load management potential is considered to be much less than the incremental load growth. CELCo therefore estimates the total load management potential for its service territory to be 19 Mw in 1995. As a result, CELCo believes that load management potential cannot be relied upon solely to eliminate the need for additional supply to the CELCo system (Exh. HO-N-23(a) and HO-N-23(b)).

The Company also asserted that there is limited potential for cogeneration within the City of Cambridge. Presently, the only plan envisioned by the Company is a 25 Mw proposed facility at MIT, for which no commitments or construction schedules have been released (Exh. HO-N-24(a) and HO-N-24(b)). The Company argues that even with the addition of this 25 Mw cogeneration facility or an equivalent production source, the need for the proposed transmission facilities would not be eliminated since the Company estimates that a total of 46 Mw of load shedding will be required in 1991 (Exh. HO-N-24(a) and HO-N-24(b)).

The Company states that even after combining estimated load management and cogeneration resources, additional load shedding would be required in 1991 without the Brighton interconnection in service. Even if 19 Mw of load management were available in 1991, as opposed to 1995, and 25 Mw of cogeneration were also available at that time, 1 Mw of load shedding still would be required if the Prospect Bulk bus and two transmission tie lines were lost and the Brighton interconnection were out of service.

The Company also examined other non-construction alternatives, including: enlarging the existing transformer banks at Brighton

Station; tapping the existing BECo 115 kv transmission cables which extend from BECo's Mystic Station to Brighton Substation; and utilizing a portion of BECo's existing duct system running through the City of Cambridge. The facilities at Brighton Substation were unable to be enlarged, due to space limitations and BECo's concern that these facilities were already the largest on the BECo system (Exh. HO-1, p. 6). The transmission cables between Mystic Station and Brighton Substation (into which CELCo's Prospect Substation supply is already tapped at Somerville Substation) are already overloaded under contingency conditions in the BECo system. Finally, since there were no spare ducts in BECo's existing duct system, the Company was unable to obtain such facilities (Exh. HO-1, p. 6, 7).

Accordingly, the Siting Council finds that the Company has adequately considered non-construction alternatives. The Siting Council further finds that since these alternatives are not practicable, there is a need for additional facilities to ensure a reliable supply of power to the City of Cambridge.

2) Construction Alternatives

To satisfy the need for the facilities identified above, the Company examined three construction options for capacity expansion: distribution expansion; generation expansion; and new transmission. Of these, the Company has determined that the transmission plan is the most desirable option because the plan has the lowest total revenue requirements and offers superior performance (Exh. HO-N-3, p. 4). The revenue requirements for each of the plans are as follows (Exh. HO-C-7):

Revenue Requirements

1986 Dollars

	Total
Distribution Plan	$561,578,000
Generation Plan	$599,594,000
Transmission Plan	$547,313,000

The distribution expansion plan involves expanding and improving the existing 13.8 kv distribution system. This would allow capacity increments to be installed as needed, closely following peak load growth. Expanding the distribution system would also achieve high system reliability because many of the system elements would carry a comparatively small amount of the total power transfer (Exh. HO-N-3, p. 2, 13, 16).

The primary difficulty the Company sees with the distribution plan is the power transfer capability of the low voltage system. The Company argues, however, that conversion to a higher voltage (34.5 kv) would be expensive and time consuming. A distribution system expansion plan is therefore limited to the existing 13.8 kv voltage (Exh. HO-N-3, p. 2, 13, 16).

Because the existing 13.8 kv distribution system is approaching its power transfer capability, the Company prefers to minimize the distance between power sources and load centers. With reductions in tie line capacity to the BBCo system, sources of generation within the CELCo system would have to be relied upon heavily. However, existing internal generation sources alone cannot be relied upon to meet demand, regardless of where these sources are situated within the system (Exh. HO-N-3, p. 2, 16).

The distribution plan has a lifetime of approximately 24 years, beyond which further capacity increases would be difficult. The distribution plan would also rely on maintaining internal power generation sources indefinitely and require a substantial amount of street trenching to install a network of ducts for transmission cables. The plan could also encounter unforseen construction costs, exceeding the estimated costs. (Exh. HO-N-3, p. 26, 29).

The generation plan involves construction of additional sources of capacity within the CELCo system and the necessary additions to the 13.8 kv distribution network to accomodate those additions. The generation plan, like the distribution plan, would allow for incremental capacity installations to closely follow system load growth, and for desirable voltage regulation throughout the system (Exh. HO-N-3, p. 3, 26, 29).

The Company states that the generation expansion plan would require the renovation of Hampshire Street Substation and permanent modifications to Prospect Street Substation. The power source for Hampshire Street Substation would be two 25 Mw combustion turbines (to offset the initial loss of 55 Mw from the Brighton interconnection), to be installed at Kendall Station. This plan would also require the Company to install two additional 25 Mw generators at Kendall Station in the seven years which follow to meet system demand, and add a fifth 25 Mw generator around 2010 to accommodate system growth (Exh. HO-N-3, p. 26).

The Company regards the generation plan as undesirable for several reasons. First, this plan entails the greatest capital and energy production costs of the three expansion options. The generation plan also has the greatest short circuit power magnitudes of the three plans.[7] The generation plan faces environmental constraints and would be subject to a lengthy permitting process. As is true for the distribution plan, the generation plan would result in no future interconnections with the BECo system other than at Alewife Substation, and would result in questionable reliability for the South Island (Exh. HO-N-3, p. 3). In summary, the Company believes that the generation plan has the highest capital and energy costs among the options, relying on expensive sources of power generation and exhibiting undesirable operational behavior in later years.

The transmission plan involves construction of a higher voltage transmission system in the City of Cambridge which would supply the existing 13.8 kv system. CELCo states that the 115 kv transmission system would be used to wheel bulk power to several key distribution points in its system. At these locations, substations would step the voltage down from 115 kv to 13.8 kv and then send the power into the existing distribution system (Exh. HO-N-3, p. 34, 35, 38).

The Company states that the transmission plan would provide better voltage control; reduce short circuit power magnitudes; essentially eliminate power transfer constraints up to the 450 Mw load level; provide for improved operating flexibility; provide a convenient means for a second interconnection with the BECo system in

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[7] "Short circuit power" is a measure of the electrical current delivered by the electrical system to a point of fault on the electrical system. A fault is the failure of a piece of electrical equipment so that energized conductors come into direct contact with the earth or any return path back to the source of electrical energy. This fault or short circuit path inherently presents a very low resistance to the flow of electric current giving rise to high currents within the electrical system. This abnormally high current would then be detected by protective relay equipment which can control the operation of power circuit breakers to open and disconnect the failed equipment from this remainder of the electrical system (Exh. HO-D-1).

future years; entails the lowest total and energy production costs of the three plans; is the least sensitive to load growth; requires the least amount of modification to the existing 13.8 kv system; and permits future retirement of all internal sources of generation. Finally, the CELCo states that the transmission plan is the only option capable of meeting system demand beyond the 350 Mw load level (Exh. HO-N-3, p. 34, 35).

The Company also notes that while the transmission plan has its capital revenue requirements that are 9.8 percent higher than the requirements for the distribution plan, the transmission system will provide 28 percent more capacity than the distribution plan (450 Mw versus 350 Mw) (Exh. HO-N-3, p. 4).

The Siting Council finds that the Company has adequately examined both distribution and generation options in order to meet the need established in Section III. B. Accordingly, the Siting Council finds that the transmission plan is preferable to both the distribution plan and the generation plan.

IV. DESCRIPTION AND COMPARISON OF PROPOSED FACILITIES AND ALTERNATIVES

A. Description of the Proposed Facilities

1) The Transmission Plan Overview

The transmission plan involves construction of both a 115 kv/13.8 kv substation and 115 kv transmission line. The proposed substation, Putnam Substation, would be constructed on a Company-owned parcel of land on Putnam Avenue in Cambridge and connected to Alewife Station by means of the proposed 115 kv transmission line (Exh. HO-1, p. 3).

The transmission line would consist of two pipe-type cables, enclosed in a welded six to eight inch steel pipe and immersed in non-PCB (polychlorinated biphenyl) mineral insulating oil. Each cable will have a nominal capacity of 200 Mw (Exh. C-1-3). The Company asserts that although pipe-type cables are in general, extremely reliable, the Company would install two cables for redundant supply to the proposed substation.

Each of the pipe-type cables would consist of three insulated copper conductors in the oil pipe and would be maintained at a pressure of 200 pounds per square inch accomplished by means of an oil pumping plant located at Alewife Substation. The entire system would be cathodically protected and grounded. The proposed line would be built so as to conform to the DPU's Code for the Installation and Maintenance of Electric Transmission Lines (Exh. C-1-3).

According to the Company, construction of the proposed pipe-type transmission cables would require digging a trench at least thirty inches deep to accommodate placing the two coated steel pipes approximately two feet on center apart from each other into a concrete envelope. The Company has stated that the trench would be opened to the required depth and would not exceed 500 feet of continuous, open trench at any one time; at the end of each work day, the trench would be backfilled to within fifty feet of the most recently completed pipe joint with steel plates placed over the trench to allow access to homes or businesses. According to the Company, several work crews at various locations would be employed to expedite construction of the project. After completion of temporary paving by the Company, CELCo has stated that all excess backfill material would be removed from the site. The pipe-type cables would be encased in a minimum of three inches of concrete and located a minimum of thirty inches below final grade. The Company has stated that the surface of the trench would be restored to a condition at least equivalent to the conditions which existed before the project began (Exh. C-1-3).

The proposed transmission line is designed to minimize the need for manholes and any repaving of city streets would conform to the standards of the city, state, or other agency having jurisdiction. CELCo states that throughout the project construction, the Company will make available a representative to address the concerns of local residents that might arise (Exh. C-1-3).

2) The Proposed 115 kv Transmission Line

a. Proposed Route

The transmission plan entails construction of a 115 kv transmission line approximately four miles in length from Alewife Station to the proposed substation on Putnam Avenue. The City Streets route, as shown in Figure 3, begins at Alewife Substation and travels south along Wheeler Street and then southeast along Concord Avenue until reaching Bay State Road and heading in an easterly direction. The route then turns off Bay State Road onto Field Street until reaching Garden Street. The route continues southeast along Garden Street until reaching Chauncy Street, where it heads east and crosses Massachusetts Avenue onto Everett Street. The route continues east along Everett Street until reaching Oxford Street. Heading south

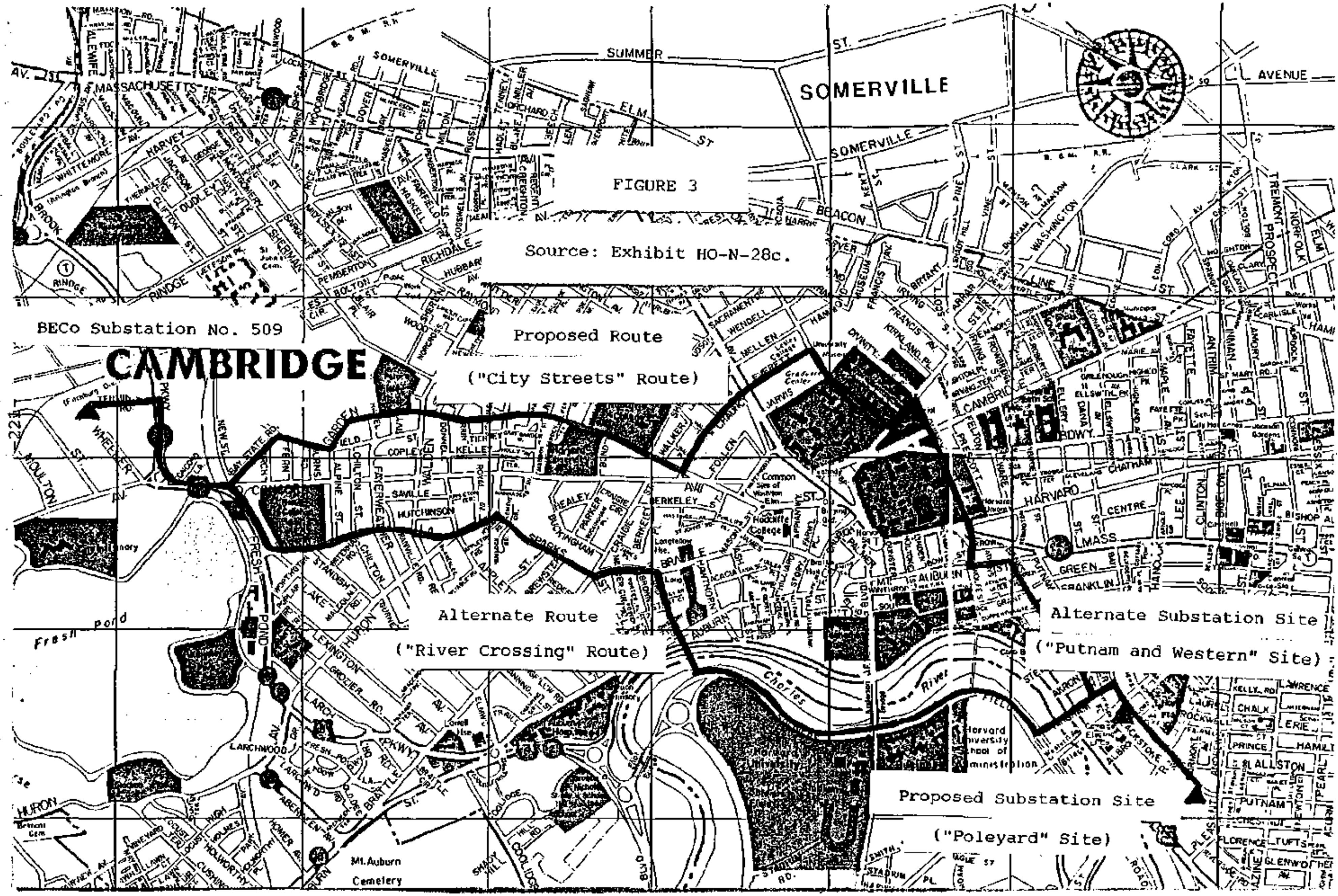
FIGURE 3
Source: Exhibit HO-N-28c.
BECo Substation No. 509
Proposed Route
("City Streets" Route)
Alternate Route
("River Crossing" Route)
Alternate Substation Site
("Putnam and Western" Site)
Proposed Substation Site
("Poleyard" Site)
SOMERVILLE
CAMBRIDGE

along Oxford Street, the route turns east onto Kirkland Street and then south onto Quincy Street, through Quincy Square and onto Bow Street. Turning off of Bow Street and onto De Wolfe Street briefly, the route then heads east along Mount Auburn Street until reaching Banks Street. Continuing south along Banks Street, the route then turns east onto Hingham Street and then south onto Putnam Avenue, crossing Western Avenue, and terminating at the site of the proposed substation on Putnam Avenue. (Exh. HO-2 and C-1-3).

The Company has stated that prior to construction, CELCo will perform a detailed study of the selected route including existing underground structures and utilities, traffic conditions, planned street improvements, and grades. The Company states that it eventually will determine the precise location, width, and depth of all trenches along the selected route in accordance with study results (Exh. C-1-3).

The costs of constructing the proposed transmission line route in October 1986 dollars can be found in Appendix A. The proposed route has an estimated present value cost of $9,699,000 if the substation is constructed at the proposed location and $9,114,000 if the substation is constructed at the alternate location. The Company estimates that final engineering design, acquisition of material and construction would require thirty months after regulatory approvals have been obtained (Exh. HO-1, p. 5).

b. <u>Alternate Route</u>

The Company has also proposed an alternate route ("River Crossing Route") between Alewife Substation and the proposed substation location as shown in Figure 3. Like the proposed route, the alternate route begins at Alewife Substation and heads south on Wheeler Street, turning southeast onto Concord Avenue. Here, the alternate route heads south along the Boston & Maine Railroad line and then crosses Fresh Pond Parkway heading southeast along Vassal Lane until reaching Sparks Street where it heads south, crossing Craigie Street onto Brattle Street. Travelling along Brattle Street turning south onto Willard Street, the route enters the Charles River Basin National Register District. The route proceeds to cross the Charles River into Boston, travelling southeast along the river through Boston and re-crossing the river back into Cambridge onto Hingham Street. Following Hingham Street in an easterly direction, the route then goes south on Putnam Avenue until reaching the site of the proposed substation (Exh. C-1-3).

According to the Company, locating the transmission line along this alternate route would not alter the proposed facility, which would be constructed using the same practices as would be used on the proposed route with the exception of the river crossing. A manhole would be installed at each side of the river crossing and a trench would be dug along the river bottom between the manholes approximately ten feet wide and four feet deep. A six inch layer of clean gravel would be placed in the trench, upon which the two pipe-type cables would be placed and then covered with a minimum of at least three feet of clean thermal sand or gravel to maintain thermal conductivity (Exh. HO-2, p. 7).

Final engineering design, acquisition of material and construction is also estimated to require thirty months from obtaining all necessary permits (Exh. HO-2, p. 7). The costs of constructing the alternate transmission line route in October 1986 dollars can be found in Appendix A. The alternate route has an estimated present value cost of $9,009,000 if the substation is constructed at the proposed location and $8,425,000 if the substation is constructed at the alternate location.

3. The Proposed 115 kv/13.8 kv Substation

In addition to the proposed transmission line, the transmission plan requires the construction of a 115 kv/13.8 kv substation in the vicinity of the existing Blackstone Station. CELCo believes that locating a substation on Putnam Avenue would allow the transformers to be located near the load center, which in turn would allow for better voltage regulation (Exh. HO-N-3, p. 4). As proposed, the substation would initially consist of an eight-breaker, 115 kv ring bus with two of the positions being used for the proposed dual-cable transmission line and two positions being used for two 50 MVA transformers. The Company states that two transformers are required because the low impedance[8] of the supply circuit causes transformers to load heavily (Exh. HO-N-3, p. 34).

To construct the proposed substation, CELCo would clear the site of the proposed substation and level all buildings or obstructions. A reinforced concrete slab would be poured to serve as the foundation for the substation. The substation would consist of a two-story 70-by-100 foot building and a one-story 75-by-105 foot building. Both

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[8] Impedance is the total opposition offered by an electric circuit to the flow of an AC circuit of a single frequency: it is a combination of resistance and reactance and is measured in ohms.

buildings would be steel-framed and constructed with masonary brick. The transformers would be enclosed with soundproof blocks and located inside the single story building. The site would also be fenced and enclosed (Exh. C-1-3, HO-F-3).

CELCo states that it will design the substation so as to blend in with the surrounding area, and to meet or exceed the requirements of all state and local ordinances (Exh. C-1-3).

a. Proposed Location

The proposed location is on a parcel of Company-owned land known as "the Poleyard" and located on Putnam Avenue as shown in Figure 3. The proposed substation would be the southeastern terminus of the proposed transmission line and its site has been planned for a location where it can easily connect into CELCo's distribution system (Exh. C-1-3).

The proposed location is zoned for business, professional offices and multi-family dwellings. At present, the Company leases use of a portion of the Poleyard site to a private business. CELCo uses the remainder of the site for storage of Company equipment (Exh. C-1-3).

The cost of constructing the substation at the proposed location is $5,730,604 in October 1986 dollars (See Appendix A). These construction costs are independent of the route selected for the transmission line (Exh. HO-C-5(a), HO-C-5(b), HO-C-5(c) and HO-C-5(d)).

b. Alternate Location

The Company also identified an alternate location for the proposed substation on a parcel of Company-owned land at the corner of Putnam and Western Avenues, approximately one and one-half blocks north of the proposed location. The alternate location is also zoned for business, professional offices and multi-family dwellings. The alternate site is adjacent to the existing Blackstone Station, as well as to a 13.8 kv underground feeder distribution substation and a 4.16 kv distribution substation which serves local area loads. On the actual site are two multiple unit dwellings, owned by the Company and consisting of sixteen rental units.

These residential buildings are subject to rent control laws in the City of Cambridge (Exh. C-1-3 and HO-C-2(a)). Therefore, before the substation could be constructed at this alternate location, local permits such as removal permits from the Rent Control Board would be required.

Constructing the substation at the alternate location would entail the same practices as outlined in Section IV. A. 3) a. The completed substation would also have the same design and appearance as that described for the proposed location.

The cost of constructing the substation at the alternate location is $5,011,604 in October 1986 dollars (See Appendix A). These construction costs are independent of the route selected for the transmission line (proposed or alternate). These total construction costs are lower than the costs for the proposed location because of lower costs for building and site preparation ($1,100,000 versus $1,325,000) and for fencing, conduit, and grounding ($525,000 versus

$1,019,000) (See Appendix A). These lower costs are related in part to the proximity of the alternate substation location to the existing Blackstone Substation, with which the proposed substation would interconnect.

Although the Company has designated this site as an alternate, it regards this alternative as an undesirable alternative for several reasons. First, the alternate location is one which has been subject to "serious and unresolved permitting impediments" (Exh. HO-10). The Cambridge City Council, while endorsing the designation of the Company's primary location on Putnam Avenue, has joined with the Cambridge Rent Control Board in strongly opposing location of the substation at this alternate site. Therefore, the Company does not anticipate that local permits will be granted within any predictable time period (Exh. HO-10).

In addition, the Company has stated that use of this alternate location would be considered only after tenants currently residing in the rent-controlled properties were to accept a plan for relocation. To date, however, the tenants have opposed all relocation plans proposed by the Company (Exh. HO-10). The Company believes that the public interest would not be well served by pressing these tenants to accept undesirable relocation arrangements and by pressing for support from the Cambridge City Council and the Cambridge Rent Control Board, when the proposed substation site is available (Exh. HO-10).

B. Analysis of the Facility Plans and Proposals

1) Adequacy of the Range of Practical Alternatives

As part of its review of proposals to construct facilities, the Siting Council requires that companies consider a reasonable range of alternative approaches to constructing those facilities. In Re Boston Edison Company, 13 DOMSC 63, 77 (1985); Massachusetts Electric Company, et. al., 13 DOMSC 119, 190 (1985); Hingham Municipal Lighting Plant, 14 DOMSC 7, 22 (1985). The Company has considered several routing alternatives to the facilities proposed to import power into the South Island section of the system.

In addition to the proposed and alternate routings for the transmission line, the Company also considered four other routes but found each one to be unfeasible. The first route would have gone through the City of Somerville, but would have been the longest and most costly alternative, involving heavily traveled streets. Another route would have used the Boston & Maine Railroad routes, but was rejected because of problems related to construction of the facilities. A route through the Massachusetts Bay Transit Authority ("MBTA") tunnels was also considered, but the MBTA was unwilling to allow oil-filled cables in the tunnels because of potential fire hazards and installation problems. Finally, a route along Rindge Avenue was considered, but was found to be longer and more costly than the proposed route (Exh. C-1-3).

With regard to the proposed substation, the Company has considered several other locations. A primary consideration in the selection process was proximity to the bulk distribution supply, Blackstone Station. One location considered was the site presently occupied by a parking lot near Tree Land Nursery, but the Company considered this location too small, situated too close to nearby housing, and not owned by the Company. A second location at the Blackstone Station site was considered, but underground oil storage tanks prohibited any building there. A lot adjacent to Blackstone Station was also considered by the Company, but other utilities' existing duct work under this lot prohibited any building on this site. A final site considered was land currently used as a parking lot on Blackstone Street, but the owner of that parcel of land was not willing to sell (Exh. C-1-3).

Accordingly, the Siting Council finds that the Company has examined a reasonable range of alternatives, as well as the "no build" alternative, and has presented primary and alternate plans for construction of both a transmission line and substation which satisfy the reliability standards identified in Section III, supra, as well as the Siting Council requirements for facility proposals as set forth in G. L. c. 164, sec. 69I and Rule 64.8(3). Based on the Company's presentation of evidence on the economic and environmental aspects of these alternative sites, the Siting Council finds that none of these alternatives appear to be practical when compared with the Company's proposals.

2) Comparison of the Proposed and Alternate Plans

The Siting Council compares the Company's facility plans and proposed and alternate transmission line routes and substation locations by reviewing the cost, environmental impact, and reliability of each alternative. Because there is a proposed and alternate route or location for both the transmission line and the substation, there are essentially four plans to be reviewed:

1) proposed transmission route and proposed substation location;
2) alternate transmission route and proposed substation location;
3) proposed transmission route and alternate substation location;
4) alternate transmission route and alternate substation location.

a. Cost

The Company estimated the costs of the four project options in two ways: first, in terms of direct construction costs; and then in terms of the present value of revenue requirements.

Total project cost estimates for the four facility plans are:

Total Project Costs
(October 1986 Dollars)

	Substation Location	
Transmission Route	Proposed (Poleyard)	Alternate (Putnam & Western Avenue)
Proposed (City Streets)	$15,429,604	$14,125,604
Alternate (River Crossing)	$14,739,604	$13,436,604

(Exh. HO-C-5). See Appendix A.

The net present value of revenue requirements associated with each of the four construction plans are:

Net Present Value of Revenue Requirements
(October 1986 dollars)

	Substation Location	
	Proposed (Poleyard)	Alternate (Putnam & Western Avenue)
Transmission Route		
Proposed (City Streets)	$629,876,000	$625,900,000
Alternate (River Crossing)	$628,733,000	$624,759,000

(Exh. HO-C-6). In this cost analysis, the Company estimated the present worth of system revenue requirements needed to cover the project's capital costs, line losses and energy production costs over the project's life cycle (Exh. HO-C-6).

As discussed above, construction of the substation at the alternate (Putnam and Western Avenue) site involves replacement housing for tenants along with associated relocation and legal expenses, as well as interim system modifications. The Company estimated that the additional costs that would be incurred in securing the alternate site would range between $1,125,000 and $1,510,000 (Exh. HO-RR-1). Adjusting the Company's cost estimates to include an average value for these additional costs produces the following estimate of total project costs:

Total Project Costs
(October 1986 Dollars)

	Substation Location	
	Proposed (Poleyard)	Alternate (Putnam & Western Avenue)
Transmission Route		
Proposed (City Streets)	$15,429,604	$15,443,104*
Alternate (River Crossing)	$14,739,604	$14,754,104*

* Includes the average added estimated expenses associated with securing the alternate site.

The results of the project cost analysis and the present worth of revenue requirements analysis without consideration of the expenses associated with securing the alternate substation site produce a nearly identical ranking of the four plans in terms of their cost. However, once the anticipated average expenses associated with securing the alternate substation site are included in the analysis, and taking into account only economic costs, the least costly plan then becomes construction of the alternate transmission route and proposed substation site and the most expensive plan becomes construction of the proposed transmission route with the alternate substation site.

b. Environmental Impact

The Company has identified short-term and long-term environmental impacts associated with the proposed and alternate transmission line routes.

The Company asserts that construction of the proposed transmission line route, involving an underground line below city streets, will impose no permanent impacts affecting land use, water resources, air quality, solid waste, radiation, or noise. The major impacts identified by the Company occuring during construction of the line include: above-normal noise levels; fugitive dust; disruption of traffic patterns including minor residential access and egress problems; and restricted use of open space on the Metropolitan Distric Commission park traversed by the line (Exh. HO-E-6). The Company has stated that it will attempt to reduce these short term construction impacts by scheduling construction during hours of the day which will least interfere with the normal routines of local area residents; simultaneously constructing various portions of the route to reduce total construction time; using dust-reducing agents to minimize airborne dust; and back-filling construction trenches as soon as the pipe-type cable is installed, with placement of steel plates over all unsurfaced sections of the trench, to allow residents access to their homes. Finally, the presence of manholes along the route could present minor long-term impacts along with occasional inspection of the transmission line by work crews (Exh. HO-E-6).

According to the Company, construction of the alternate transmission line route would impose several short term impacts affecting land use and water resources associated with the construction in city streets and the dredging of two trenches across the Charles River. The impacts along city streets are the same as those outlined above for the proposed route. The environmental impacts directly associated with the river crossing are specific to this route. The Company states it would have to establish an area along the banks of the river from which to direct operations, creating undesirable visual impacts along the riverbanks during operations as well as the possibility of degradation to sensitive areas in the Charles River Basin National Register District as a result of heavy construction-related traffic. Sediments and materials dredged and removed from the river bottom must be disposed of at an approved disposal site via trucks. Before removing these sediments from the site, CELCO must drain them, creating odor problems and requiring additional land area at the site to be temporarily inaccessible to the public (Exh. HO-C-6).

CELCO states that the dredging operation will increase particulate suspension in the river which could increase deposition of silt downstream and turbidity problems in the immediate vicinity of the operation. The Company has stated that it will attempt to reduce siltation problems by using a hydraulic dredge and by controlling the effluent created by the dewatering process to reduce the amount of suspended material returned to the river. In general, the Company states that it will attempt to minimize these and other environmental impacts associated with the dredging operation by completing this phase of the project as quickly as possible and returning the area to its original condition (Exh. HO-E-6).

The Siting Council finds that both the proposed and alternate transmission line routes would impose short-term as well as possible minor long-term environmental impacts resulting from the construction of the transmission line below city streets. The Siting Council finds further that the alternate route would impose additional short term impacts as a result of the dredging operation across the Charles River. Accordingly, the Siting Council finds that the proposed route produces fewer adverse environmental impacts than does the alternate route and is therefore consistent with minimizing environmental impacts.

Further, while the Siting Council recognizes the value of a detailed study prior to construction of the transmission line, it can not support in advance any flexibility as to routing based on the prospective results of such a study alone. Accordingly, the Siting Council will require the Company to obtain Siting Council approval if CELCo believes that the route, as approved, should be changed. See Section V, *infra*.

The Company states that construction of the proposed substation at either the proposed or alternate location imposes minimal adverse impacts affecting water resources, air quality, solid waste, radiation, or noise. During construction of the substation at either site, there will be some above-normal fugitive dust and noise levels above normal. The transformer enclosures would be made of soundproof blocks with brick veneer facing compatible with the substation. The site would be fenced and enclosed. The proposed substation at either the proposed or alternate location would meet or exceed all state and local ordinances. Accordingly, the Siting Council finds that the environmental impacts associated with the proposed and alternate substation sites are negligible.

c. Reliability

Both routes involve two underground pipe-type cables, either of which would be able to serve the City of Cambridge until approximately 2003 (325 MW peak load). Since both routes involve installing the same cables in cathodically protected steel pipe, the Company considers both routes to have the same protection and reliability of service (Exh. HO-N-26).

Accordingly, the Siting Council finds that there is essentially no difference in reliability between the proposed and alternate transmission routes. Either route would meet the Company's reliability criteria as outlined above in Section III. B.

d. Conclusion

The Siting Council finds that the proposed and alternate transmission line routes as well as the proposed and alternate substation sites meet the need established in Section III., *supra*.

A comparison of total project costs reveals that the Company's alternate route and proposed substation site is the least costly of the four options presented. See Section IV. B. 2) a., *supra*. However, the Siting Council has rejected the alternate route because of adverse environmental impacts. See Section IV. B. 2) b., *supra*. Accordingly, the Siting Council finds that the Company's proposed route is preferrable to its alternate route.

Therefore, the Siting Council must determine which substation site is consistent 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. Since the environmental impacts associated with both the proposed and alternate substation sites are negligible (see Section IV. B. 2) b., *supra*), the Siting Council's determination must be based on a cost comparison. As discussed above, the alternate substation site, including the costs associated with replacement housing, tenant relocation and legal expenses, and interim system modifications, is more costly than the proposed substation site. See Section IV. B. 2) a., supra.

Accordingly, the Siting Council concludes that the Company's proposal to construct the 115 kv transmission line along the City Streets route and its proposal to site the 115 kv/13.8 kv substation at the proposed Poleyard location are consistent with ensuring an adequate, least-cost energy supply at minimum environmental impact.

V. DECISION

The Siting Council hereby APPROVES the Petition of the Cambridge Electric Light Company to construct an underground 115 kv transmission line along the proposed route and to construct a 115 kv/13.8 kv substation at the proposed site on Putnam Avenue subject to the following conditions:

1) That after conducting its pre-construction study, the Company shall not deviate from the approved route without receiving approval from the Siting Council.

2) That during the entire construction process, the Company make available a representative from CELCo to talk to area residents and address any problems that may arise during construction.

Robert D. Shapiro

Robert D. Shapiro

Hearing Officer

December 18, 1986

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of December 18, 1986, by the members and designees present and voting: Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Joellen D'Esti (for Joseph Alviani, Secretary of Economic Affairs); Joseph W. Joyce (Public Labor Member). Ineligible to vote: Acting Chair Dennis J. LaCroix (Public Gas Member); Elliot J. Roseman (Public Oil Member). Absent: Madeline Varitimos (Public Environmental Member); Sharon M. Pollard (Secretary of Energy Resources). Recused from vote: Stephen D. Umans (Public Electricity Member).

12/19/86

Date

Dennis J. LaCroix

Dennis J. LaCroix

Acting Chairperson

APPENDIX A

Itemized Total Project Construction Costs
(October 1986 Dollars)

Transmission Line

(Transmission Route) (Substation Site)	(Prop.) (Prop.)	(Prop.) (Alt.)	(Alt.) (Prop.)	(Alt.) (Alt.)
Cable, Cable Installation, Pipe and Pipe Installation	7,460,000	6,960,000	6,900,000	6,400,000
Paving	932,000	870,000	837,000	775,000
Termination and Miscellaneous Equipment	325,000	325,000	325,000	325,000
Oil Pumping Station and Oil	482,000	459,000	447,000	425,000
Engineering and Contingencies	500,000	500,000	500,000	500,000
Total	$9,699,000	$9,114,000	$9,009,000	$8,425,000

Substation

Two Transformers 30/40/50 MVA	903,604	903,604	903,604	903,604
SF6-4 Breaker Ring Bus 115 kv Minisub	1,150,000	1,150,000	1,150,000	1,150,000
15 kv Breakers, Relaying, Disc, Cubicles	950,000	950,000	950,000	950,000
Building and Site Preparation	1,325,000	1,100,000	1,325,000	1,100,000
Supervisory Control System	28,000	28,000	28,000	28,000
Fence, Grounding MH's Conduit and Cable	1,019,000	525,000	1,019,000	525,000
Duct and MH System	55,000	55,000	55,000	55,000
Engineering and Contingencies	300,000	300,000	300,000	300,000
Total	$5,730,604	$5,011,604	$5,730,604	$5,011,604
Total Costs	$15,429,604	$14,125,604	$14,739,604	$13,436,604

Source: Exh. HO-C-5.

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Massachusetts Electric Company, New England Power Company, Yankee Atomic Electric Company, and Manchester Electric Company for Approval of Supplement 2B of their Second Long Range Forecast of Electric Resources and Requirements	EFSC Docket No. 83-24

FINAL DECISION

Robert D. Shapiro
Hearing Officer

On the Decision:

Susan Fallows Tierney

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The Energy Facilities Siting Council ("Siting Council") hereby finds that Massachusetts Electric Company, New England Power Company, Yankee Atomic Electric Company, and Manchester Electric Company ("the Companies") are in compliance with the Siting Council's Order in Docket No. 76-24 (hereinafter the "1977 Order").[1]

I. INTRODUCTION AND HISTORY OF THE PROCEEDINGS

A. Description of the Companies

The Massachusetts Electric Company ("MECo") and the New England Power Company ("NEPCo") are wholly owned subsidiaries of the New England Electric System ("NEES").

NEPCo is a bulk power supply company and provides generation and major transmission facilities for NEES' retail subsidiaries, which include MECo and Manchester Electric Company in Massachusetts, and companies in Rhode Island and New Hampshire.

All of the NEES Companies are members of the New England Power Pool ("NEPOOL"). As such, the planning of their bulk transmission facilities is done within a regional framework. The operation of NEPCo and NEES facilities is under the control of the NEPOOL dispatch center, the New England Power Exchange ("NEPEX").

1/ In a Procedural Order dated September 29, 1983, the Hearing Officer ordered that the Siting Council's review of the Companies' Long-Range Forecast of Electric Resources and Requirements ("1983 Forecast") would be conducted in two phases. The Phase I issues, i.e., compliance with the 1977 Order, are the subject of the current decision. The remaining issues associated with the 1983 Forecast were to be the subject of a Phase II. The Siting Council's subsequent approval of the Companies' 1984 Forecast of Electric Resources and Requirements has obviated the need to adjudicate the Phase II issues of Docket No. 83-24 (Massachusetts Electric Company et al., EFSC 84-24, 12 DOMSC 197 (1985)).

B. Overview

In this case, the Siting Council has been asked to determine whether the Companies have complied with the conditions set forth in its approval of two transmission lines in its 1977 Order, Massachusetts Electric Company et al., EFSC 76-24, 2 DOMSC 1, 4-6 (1977), in light of changed circumstances, and, if not, whether a modification of that Order is warranted.

The two facilities in question are both high-voltage transmission lines. One, known here as the "Amesbury-Tewksbury line," would extend from an existing substation in Tewksbury, Massachusetts, to the Massachusetts state line in Amesbury, where it would connect with a line the Public Service Company of New Hampshire ("PSNH") proposed to build from the Seabrook nuclear power plant in Seabrook, New Hampshire. 2 DOMSC 1, 2. The second line, known here as the "Dracut-Tewksbury line," would run from the existing substation in Tewksbury to the Massachusetts border in Dracut, where it would connect with a line PSNH proposed to run to a substation at Scobie, New Hampshire. 2 DOMSC 1, 5.

Specifically, the Siting Council now has been asked to determine whether the Companies have satisfied the conditions in Order No. 76-24 that the Companies "...undertake construction [of the Amesbury-Tewksbury line and the Dracut-Tewksbury line] in a manner which is consistent with the construction program at the Seabrook facility." 2 DOMSC 1, 4-6.

C. History of the Proceedings

On May 2, 1983, the Companies filed their 1983 Forecast with the Siting Council. The Companies provided notice of the proceeding by publication and posting in accordance with the directions of the Hearing Officer.

On June 22, 1983, the Siting Council received a Petition to Intervene from State Senator Nicholas Costello ("Costello"). At a pre-hearing conference held on June 24, 1983, the Companies expressed their opposition to Costello's petition. On July 6, 1983, pursuant to an agreement between the parties, Costello submitted a Memorandum in Support of the Petition to Intervene. On July 18, 1983, the Companies submitted their Memorandum in Opposition. On August 10, 1983, after consideration of memoranda and oral argument from both parties, the Hearing Officer issued a procedural order granting Costello's Petition to Intervene for the limited purpose of allowing him to address the issues of whether the Companies were in compliance with the Siting Council's 1977 Order and whether, as a result of changed circumstances, the Siting Council should modify that Order.

On August 17, 1983, the Companies filed a Motion for Review of the Hearing Officer's August 10, 1983 Procedural Order. On September 8, 1983, the Siting Council's Director, Charles McMillan, notified the Companies that their Motion for Review would not be placed on the Siting Council's agenda, stating that no statute or regulation allowed such an interlocutory review.

On September 5, 1983, the Attorney General of Massachusetts ("Attorney General") notified the Hearing Officer that the Attorney General would be submitting a late-filed petition to intervene in the case. On September 7, 1983, the Siting Council conducted a second pre-hearing conference in this proceeding. At the conference, the Companies voiced their opposition to the Attorney General's possible intervention while Costello reserved judgment on the issue.

On September 13, 1983, the Attorney General filed a Petition to Intervene. On September 16, 1983, Costello notified the Hearing Officer that he supported the Attorney General's intervention. On September 21, 1983, the Companies filed their response to the Attorney General's petition. On September 26, 1983, the Attorney General filed a Reply to the Companies' response. On September 29, 1983, the Hearing Officer issued a procedural order granting the Attorney General's petition. At the same time, the Hearing Officer ruled that the scope of the proceeding would be expanded to include both the Dracut-Tewksbury line and the Amesbury-Tewksbury line.[2]

2/ The Hearing Officer also noted that the intervenors had not indicated an intention to present a case on environmental issues, instead limiting the scope of their inquiry to need and cost issues (Procedural Order, September 29, 1983, p. 3). In fact, there was no evidence presented on environmental issues in the proceeding.

On December 12, 1983, pursuant to Siting Council Rule 15.3, the New England Power Pool ("NEPOOL") filed a Petition to Participate as an Interested Person in the proceeding. On December 14, 1983, the Boston Edison Company ("BECo") filed a similar petition. On December 30, 1983, the Companies filed a Statement in Support of the NEPOOL and BECo petitions. On January 3, 1984, Costello filed his Opposition to the NEPOOL and BECo petitions.

On December 15, 1983, the Siting Council conducted a third pre-hearing conference in this case.

On January 18, 1984, the Hearing Officer issued a procedural order granting Interested Person status to NEPOOL, while denying the BECo petition. In granting the NEPOOL petition, the Hearing Officer noted NEPOOL's unique position as a central electric facility planning authority. In denying interested person status to BECo, the Hearing Officer ruled that BECo had failed to set out a specific interest in the proceeding that was not already adequately represented by NEES and NEPOOL.

Evidentiary hearings commenced on January 24, 1984, and concluded on February 24, 1984. In all, eight days of evidentiary hearings were held. The Attorney General presented one witness, Paul L. Chernick, a research associate for Analysis and Inference, Inc., who testified on the issues of need and cost. Costello presented one witness, Dr. Peter Graneau, an electrical engineer employed by the Underground Power Corporation, who testified on the issues of need and cost.

The Companies sponsored one witness, Robert O. Bigelow, vice-president of NEPCo and director of the Power and Planning Supply Division of New England Power Service Company, a subsidiary of NEES. Mr. Bigelow also testified on the issues of need and cost.

Pursuant to a briefing schedule established by the Hearing Officer, the Attorney General, Costello, the Companies and NEPOOL filed their initial briefs on March 26, 1984. On April 9, 1984, the Attorney General, Costello and the Companies filed reply briefs.

On April 9, 1984, the Companies also filed a Motion to Strike certain portions of Costello's initial brief on the grounds that it included "testimony unsupported by any witness and not subject to cross-examination or rebuttal testimony." On April 17, 1984, Costello filed a Memorandum in Opposition to the Companies' motion. On April 18, 1984, the Attorney General submitted a letter in opposition to the Companies' Motion to Strike. On April 26, 1985, the Hearing Officer issued a Procedural Order denying the Companies' motion.

On September, 17, 1986, the Town of Amesbury ("Amesbury") filed a Petition to Intervene in the proceeding. On October 10, 1986, the Companies and NEPOOL filed their responses in opposition to Amesbury's petition. On November 5, 1986, the Hearing Officer issued a Procedural Order denying Amesbury's petition, stating that Amesbury had failed to demonstrate: (1) that its entrance as an intervenor at a late stage in the proceeding would assist the Siting Council; and (2) that its position was unique and not adequately represented by other parties to the proceeding.

On October 15, 1986, the Town of West Newbury ("West Newbury") filed a Petition to Intervene in the proceeding. On November 17, 1986, West Newbury requested that its petition be "held in abeyance and that no action be taken on the Petition at this time."

II. SITING COUNCIL DECISION IN DOCKET NO. 76-24

In 1976, the Companies filed their Long Range Forecast in which they petitioned the Siting Council for approval of a package of transmission facilities. On June 15, 1977, the Siting Council issued an order in Docket No. 76-24 (hereinafter, the "1977 Order") conditionally approving facilities that included the Amesbury-Tewksbury and Dracut-Tewksbury transmission lines.

A. Amesbury-Tewksbury Line

NEPCo had proposed to build a 31.9-mile 345 kV transmission line from an existing substation in Tewksbury to the state line in Amesbury, where it would tie into a line proposed by PSNH to extend from Amesbury to its proposed Seabrook nuclear plant ("Seabrook") in New Hampshire. (Hereinafter, when referenced together, these transmission lines will be known as the "Seabrook-Tewksbury line.") See Figure 1. The Amesbury-Tewksbury line was proposed to be built on an existing right-of-way, of which all but two miles was already occupied by one or more transmission lines. In Re Massachusetts Electric Company et al., 2 DOMSC 1, 2-3 (1977).

NEPCo had stated that the line was needed for two reasons: (1) to connect Seabrook to the main 345 kV transmission grid in New England (hereinafter "the grid"); and (2) to provide a source of supply to the 115 kV transmission system in northeastern Massachusetts by means of NEPCo's proposed new substation at Boxford Junction (76-24 Hearing dated 3/24/77, pp. 3-84, 3-85). The Companies had submitted evidence that the proposed line was one of three needed under federal nuclear plant licensing requirements to carry power from Seabrook to the grid (Id., pp. 4-91, 4-92). Also, NEPCo testified that without the Seabrook-Tewksbury line, the existing transmission facilities between northern and southern New England would be insufficient to absorb the new power from Seabrook (76-24 Exhibit N-16B, pp. 4-5).

In its 1977 Order, the Siting Council found the Amesbury-Tewksbury line was needed and was consistent with the Siting Council's mandate to ensure a necessary power supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost, "subject, however, to the following conditions. The Council finds that the need for the line...is directly dependent on the completion of the Seabrook nuclear plant...because its purpose is to carry power from the plant....The Council approves these facilities; however, the Council directs the Company to undertake construction in a manner which is consistent with the construction program at the Seabrook facility." 2 DOMSC 1, 4.

B. Dracut-Tewksbury Line

NEPCo also had proposed a 6.6-mile 345 kV line to run from the Tewksbury substation to the state line in Dracut, from where it would continue on to a proposed PSNH substation at Scobie Pond, New Hampshire. The Companies stated that the entire line (hereinafter the "Scobie-Tewksbury line") was needed coincident with the operation of the second nuclear unit at Seabrook, so as to provide for reliable power flows from New Hampshire to the Massachusetts transmission grid (76-24 Hearing dated 3/24/77, pp. 4-96, 4-97).

The Siting Council's 1977 Order approved the Dracut-Tewksbury line but, as with the Amesbury-Tewksbury line, conditioned it upon the Companies' building it "in a manner which is consistent with the construction program at the Seabrook facility." 2 DOMSC 1, 6.

III. STANDARD AND SCOPE OF REVIEW

The current case presents the Siting Council with an array of issues which are not generally addressed in facility review proceedings. In a typical facility review case, the Siting Council evaluates a petitioner's proposal pursuant to G.L. c. 164, sec. 69H. Here, the intervenors have asked the Siting Council to determine whether the Companies, in light of changed circumstances, have complied with a 1977 Order allowing them to construct a transmission line. In the event that the Siting Council finds that the Companies have not complied with the 1977 Order in light of changed circumstances, the intervenors ask the Siting Council to determine whether the Company's non-compliance warrants modification of the earlier order.

A. The Siting Council's Authority

The Companies and NEPOOL have consistently argued that the Siting Council has no authority to review this matter and that any request for modification should be rejected as a matter of law (NEES Brief, pp. 3-7; NEPOOL Brief, pp. 3-16).

In support of their contention, the Companies argue that the Siting Council has no explicit power to modify prior forecast approvals. Principally, the Companies rely upon the language of G.L. c. 164, sec. 69I(3) which sets out certain filing requirements for a long range forecast, but exempts "facilities which have been approved as part of a previous long range forecast or supplement thereto." The Companies conclude that this statutory exemption makes "it clear that once a forecast has been approved, it becomes final and cannot be readjudicated" (NEES Brief, p. 3, incorporating by reference NEES Memorandum In Opposition to Costello Motion to Intervene, pp. 8-9).

The Companies also rely upon the Supreme Judicial Court's decision in Plymouth County Nuclear Information Committee v. Energy Facilities Siting Council, 374 Mass 236, 239-240 (1978), where the Court affirmed the Siting Council's decision exempting a facility from review because construction had commenced before the effective date of the Siting Council statute. The Companies argue that the decision in Plymouth County supports the contention that once a facility is under construction, it is not subject to further Siting Council review (NEES Brief, pp. 4-6).

In a Procedural Order dated August 10, 1983, the Hearing Officer rejected the Companies' contention that the Siting Council has no authority to review the Companies' compliance with its 1977 Order (Procedural Order, August 10, 1983, pp. 4-5). Neither the Companies nor NEPOOL have presented the Siting Council with a compelling reason to reverse the Hearing Officer's ruling.

In the August 10, 1983 Procedural Order, the Hearing Officer ruled that Costello would be allowed to intervene "solely for the purpose of addressing the issues of whether the Companies are in compliance with the Council's order in Docket No. 76-24 and whether, as a result of changed circumstances, that order should be modified" (Id., p. 7). In disputing the Siting Council's authority in this proceeding, the Companies fail to acknowledge that our review here is hinged upon a 1977 Order where the approval of proposed facilities was conditional. In granting the Companies' facilities request with a condition attached thereto, the Siting Council clearly envisioned the possibility of a later review of the Companies' compliance with that condition.

In issuing its 1977 Order with an "open ended" condition, the Siting Council retained a powerful discretionary tool which enabled the agency to review the Companies' compliance at any time. While this condition may have left the Companies unduly vulnerable to later inquiries, the Siting Council must accept the plain language of its earlier decision. That language required the Companies to proceed with construction of the transmission lines in a manner consistent with construction of the Seabrook facility. As such, the Siting Council's 1977 Order was dynamic in nature and required the Companies' to respond to changes in circumstances surrounding the construction at Seabrook.

As noted by NEPOOL, the ability of a regulatory agency to subject its decisions to conditions is not in dispute in this proceeding (NEPOOL Brief, p. 8). Pursuant to G.L. c. 164, sec. 69J, the Siting Council's authority to review facility requests is broad and does not preclude the issuance of decisions that conditionally approve a proposal for new facilities. Accordingly, we find that G.L. c. 164, sec. 69J enables the Siting Council to determine whether the Companies have complied with its 1977 Order.[3]

B. Burden of Proof

In two procedural orders issued in this matter, the Hearing Officer ruled that the Intervenors have the burden of proof with respect to the threshold question of whether the Companies have complied with the conditions set forth in the Council's 1977 Order (Procedural Order, September 29, 1983, p. 2; Procedural Order, January 4, 1984, p. 2).[4] The Siting Council finds that this burden requires the intervenors to demonstrate that the Companies have not complied with the 1977 Order in light of changed circumstances, not merely raise doubts as to the measure of their compliance.

3/ The Siting Council's decision in this proceeding makes it unnecessary to rule on the question of whether the agency has the authority to modify its 1977 Order. Similarly, the Siting Council refrains from determining whether it has the authority to review a decision in which a facilities proposal has been unconditionally approved.

4/ In light of its decision in this proceeding, the Siting Council need not reach the question of which party would have had the burden of proof in the event of a finding that the Companies had not complied with the 1977 Order.

IV. THE COMPANIES' COMPLIANCE WITH THE SITING COUNCIL'S 1977 ORDER IN LIGHT OF CHANGED CIRCUMSTANCES

The threshold question the Siting Council must address is whether, in light of changed circumstances, the Companies are in compliance with the Siting Council's 1977 Order. To answer this question, the Siting Council first reviews the parties' positions with respect to circumstances that may have changed since 1977 and whether: (1) either of the two proposed transmission lines is still needed in light of those changes; and (2) if so, which of the two lines is the least-cost route. Then the Siting Council reviews the parties' criticisms of each other's evidence and arguments. Finally, the Siting Council makes findings as to changed circumstances and the Companies' compliance with the Siting Council's 1977 Order in light of any such circumstances.

A. The Intervenors' Positions Regarding Changed Circumstances and Need for the Lines

1. The Attorney General's Position

The Attorney General, through the testimony of Mr. Chernick, noted that the following conditions existed at the time the Companies received approval of their facility proposals in Siting Council Docket No. 76-24 (Exhibit 15-AG-1, pp. 4-5; AG Brief, pp. 4-6):

(a) two 1150-megawatt ("MW") nuclear generating units were planned for construction at Seabrook Station;

(b) for reliability purposes, such a two-unit nuclear facility would require three 1000+ MW transmission lines to connect it to the grid;

(c) the three transmission lines were proposed in the following order of construction, from Seabrook north to Newington (the "Seabrook-Newington line"), from Seabrook southwest to

Tewksbury, and from Seabrook west to Scobie (the "Seabrook-Scobie line") (See Figure 2);

(d) the two-unit Seabrook station would also require two transmission lines to be built across the Massachusetts/New Hampshire border -- i.e., the "North/South Interface" of the New England transmission grid -- in order to reinforce the existing transmission network so as to absorb Seabrook's output and transmit it to load centers in southern New England;

(e) one of these two north/south transmission lines -- the Seabrook-Tewksbury line -- would be built in conjunction with Seabrook 1, and the second -- the Seabrook-Scobie-Tewksbury line -- would be timed with Seabrook 2;

(f) an alternative to the Seabrook-Tewksbury line would be a second line along the Seabrook-Scobie-Tewksbury route and would require more right-of-way and additional cost; and

(g) the Seabrook-Tewksbury line would add a source of power to northeastern Massachusetts through a new substation proposed in the Boxford area.

Mr. Chernick also identified a number of changes that had occured since 1976-1977 with respect to the circumstances listed above (Tr. I, p. 146; Exhibit 15-AG-1, pp. 5-8; AG Brief, pp. 6-7):

(a) completion of Seabrook 1 is still at least two years away (i.e., in late 1986 or early 1987), and Seabrook 2 is slated for the 1990's at the earliest, if not cancelled outright;

(b) the order of construction of the lines from Seabrook has changed, with both the Seabrook-Scobie and Seabrook-Newington lines already built;

(c) with two transmission lines already built and one nuclear plant expected, the rationale for a third line to connect Seabrook to the grid no longer exists;

(d) with one unit at Seabrook, reinforcement to the North/South Interface is needed but would require only a single new 1000+ MW transmission line;

(e) since the Seabrook-Tewksbury line is not necessary to connect Seabrook to the grid, then an alternative to the Seabrook-Tewksbury line for crossing the North/South Interface is the Scobie-Tewksbury line;

(f) the Scobie-Tewksbury line is shorter and less costly to construct than Seabrook-Tewksbury; and

(g) the Boxford Junction substation is not needed until at least 1992 and, therefore, should not be a justification for Seabrook-Tewksbury in the short run.

The Attorney General concluded that these changes have significantly altered the justification for the Seabrook-Tewksbury line since 1977. He concluded that either the Seabrook-Tewksbury line or the Scobie-Tewksbury line may be needed for transmission-system reinforcement purposes, that the two lines have roughly equal reliability benefits (Tr. I, pp. 144-145), that based on direct construction costs the Scobie-Tewksbury line is preferable (Exhibit 15-AG-1, p. 20), and that the need for the Seabrook-Tewksbury line in the 1980's has not been demonstrated (Id., p. 6).

In response to questions of the Companies, Mr. Chernick stated that his comparison of costs of the two lines did not reflect differential line loss costs or the economic penalties that could occur if the Scobie-Tewksbury line could not be built in time for Seabrook 1's commercial operation and if resultant transmission constraints prevented NEPEX from dispatching the region's generating stations in a least-cost fashion (Tr. I, pp. 122-123, 144, 147).

2. Costello's Position

Costello also identified changes that have transpired since 1976-1977 which eliminate the need for the Seabrook-Tewksbury line in conjunction with Seabrook 1. Specifically, he cited: the almost certain cancellation of Seabrook 2; the ability of Seabrook 1 to be put into service with only the two existing lines in place; the ability of either the Seabrook-Tewksbury line or the Scobie-Tewksbury line to transmit Seabrook's energy to southern New England; and the deferral of the need for the Boxford substation until the year 2000 (Costello Brief, pp. 6-8).

Costello argued that these changes demonstrate that the Seabrook-Tewksbury line is no longer required in conjunction with Seabrook 1, as was the case at the time of the Siting Council's decision in Docket No. 76-24.

Additionally, Costello's witness, Dr. Graneau, testified that the two existing 345 kV transmission lines already connected to the Seabrook site -- the Seabrook-Newington and Seabrook-Scobie lines -- are sufficient to tie Seabrook's 1150 MW into New England's transmission system (Exhibit 1-C-1, p. 3). Dr. Graneau further testified that if another line crossing the North/South Interface were necessary, the Scobie-Tewksbury line would be preferable in terms of combined line loss and incremental construction costs (Id., pp. 4-6). Dr. Graneau also stated that his cost analysis was incomplete because he lacked information on the Seabrook-Tewksbury line's sunk capital costs (Tr. I, pp. 19, 25-26), regional line loss differentials (Id., p. 72), and capacity cost component of line losses (Id., p. 84).

Finally, Dr. Graneau proposed a method for connecting the Seabrook-Scobie and Scobie-Tewksbury lines into the Scobie substation (via a three circuit breaker arrangement) so as to improve the reliability and reduce the line losses of the local transmission system (Exhibit 46-C-7, pp. 1-6).

B. The Companies' Position Regarding Changed Circumstances and Need for the Lines

1. The Companies' Position

a. Need

The Companies argued that in spite of changed circumstances, the Seabrook-Tewksbury line is still needed in conjunction with Seabrook 1 and the Companies remain in compliance with the Siting Council's 1977 Order.

The Companies' witness, Mr. Bigelow, conceded that certain changes indeed had occured since 1977. Since both the Seabrook-Newington and Seabrook-Scobie lines were in service, he agreed that Seabrook-Tewksbury was not necessary as a direct connection between Seabrook and the grid in order to meeting federal licensing requirements (Exhibit 17-N-11, pp. 17-18; Tr. III, pp. 21-24). Mr. Bigelow also agreed that: it was unlikely that Seabrook 1 would be operating before mid-1986 or early 1987 (Exhibits 35-B-14 and 64-N-14); Seabrook 2 was indefinitely delayed and would possibly be cancelled (Tr. III, p. 73; Tr. IVA, pp. 63-64; Exhibits 34-B-13 and 36-B-15); and the Boxford Substation was not needed in the foreseeable future (Tr. III, p. 27; Tr. IVB, pp. 58-59; Exhibit 40-B-19).

However, the Companies argued that some circumstances had not changed since the Siting Council's 1977 Order. The Companies asserted that they had provided evidence in Docket No. 76-24 that the Seabrook-Tewksbury line was needed in conjunction with Seabrook 1 not just to interconnect Seabrook to the grid but also because the North/South Interface needed reinforcement when Seabrook 1 came on line. In support of that contention, the Companies cited an exhibit from the record of the 1977 proceeding (NEES Brief, pp. 13-14):

> Today, there are only two 345 kV lines connecting the Northern New England system with Massachusetts. The ability of these lines to transfer power to Massachusetts is limited to

approximately 1050 megawatts. Clearly, there is a need to increase transmission capability between Northern New England and Massachusetts by the time Seabrook is in full operation. Otherwise, the significant savings which can be realized by operating the most economic pattern of generation cannot be realized. The Seabrook to Tewksbury 345 kV line is one of the additional facilities which will accomplish this economic benefit. [Docket No. 76-24, Exhibit N-16B, pp. 4-5.]

Mr. Bigelow testified that a new 345 kV transmission line was still needed to cross the North/South Interface in time for Seabrook 1. Without such a new crossing, the limited north/south transfer capability of the existing system would inhibit the ability of NEPEX to economically dispatch the region's power plants and purchases (Exhibit 17-N-11, pp. 21-22, 26). In that case, Mr. Bigelow noted that: (1) NEPEX would have to avoid reliability problems by dispatching supplies and operating the transmission system in accordance with the North/South Interface's transfer limits; and (2) these operational constraints would mean that economic penalties would occur any time the economic generation available in northern New England exceeded the sum of the northern New England loads plus the transfer limit (Exhibit 17-N-11, pp. 20-23, 25-27; Tr. IVB, pp. 9-11; Tr. II, pp. 48-49; Exhibit 61-B-27). Mr. Bigelow testified that a new transmission line was needed to be built across the North/South Interface in conjunction with Seabrook 1, just as it had been needed in 1977, to avoid "locked-in" economic generation north of the Massachusetts border (Exhibit 17-N-11, pp. 19-25).

Mr. Bigelow noted that the Scobie-Tewksbury line and the Seabrook-Tewksbury line would be roughly equivalent in terms of their ability to satisfy the need to increase the north-south transfer capability sufficiently to allow an economic dispatch with Seabrook 1 on line. However, he asserted that the Seabrook-Tewksbury line is still the line to construct in conjunction with Seabrook 1 since one line is needed and the Seabrook-Tewksbury line is the lower-cost alternative (Id., pp. 18-20, 29-30, 38).

b. Cost

The Companies argued that even in light of the changes that had occured since 1977, the Seabrook-Tewksbury line is still the least-cost line to build to meet the need for a line across the North/South Interface in conjunction with Seabrook 1 (Exhibit 17-N-11, pp. 38-40). In support of this contention, Mr. Bigelow presented the results of various cost analyses of the Seabrook-Tewksbury and Scobie-Tewksbury lines (Id., Sch. ROB-13, ROB-14, ROB-15). The Companies' cost evidence related to three types of costs: construction costs; line loss costs; and economic penalties.

i. Construction Costs

Mr. Bigelow presented several construction cost estimates for each line, where the estimates changed due to different assumptions regarding the expected completion dates for the lines and for Seabrook 1 (Exhibit 17-N-11, Sch. ROB-13, ROB-14, ROB-15).

The first analysis assumed the lines would need to be completed by December 1984, when PSNH expected Seabrook 1 to be operational (Exhibit 17-N-11, pp. 33-35, Sch. ROB-13). The second analysis assumed an in-service date for Seabrook 1 of July 1986, the planning date then used by NEES (Id., p. 35, Sch. ROB-14). Both of these studies resulted in present values (in 1983 dollars)[5] of $20.1 million for the Scobie-Tewksbury line's construction costs and $26 million to $26.7 million for the Seabrook-Tewksbury line's construction costs.

In both of these analyses, NEPCo assumed that the Seabrook-Tewksbury line could be built in time for Seabrook 1's commercial operation, but a projected 4.5-year licensing and construction lead time for the Scobie-Tewksbury line meant that the latter line could

5/ Hereinafter, all present worth figures will be expressed in terms of 1983 dollars, using a 14.24 discount rate based on the Companies' weighted incremental cost of capital (Exhibit 17-N-11, p. 33). Both the Companies and Mr. Chernick agreed that this was an appropriate basis for the discount rate (Tr. IVB, pp. 52-55; Tr. V, pp. 135).

not be completed until late 1988 (Id., pp. 30-32). To demonstrate the long lead time for Scobie-Tewksbury, the Companies provided a list of permits that had not yet been obtained from Massachusetts and New Hampshire agencies, along with a flow chart indicating the expected critical path schedule for these permits and construction activities (Id., Sch. ROB-12; Exhibit 41-B-20). The Companies also noted that their estimate of a 31.5-month permitting period and a 22.5-month construction process for the Scobie-Tewksbury line was optimistic, since it assumed no appeals or other licensing complications that had surrounded the Seabrook-Tewksbury line (NEES Brief, pp. 29-32; Exhibit 17-N-11, p. 32).

These estimates show that the Companies expected the Seabrook-Tewksbury line to cost more to construct than the Scobie-Tewksbury line.

ii. Line Loss Costs

Mr. Bigelow also calculated line loss costs associated with running the region's transmission system with one or the other of the two lines. He based his calculations on the results of line loss studies performed by NEPOOL (Exhibit 17-N-11, p. 34, Sch. ROB-13, ROB-14, ROB-15). These results showed that with the Seabrook-Scobie-Tewksbury route for the line crossing the North/South Interface, regional line losses would be higher than with the Seabrook-Tewksbury line (Id.). The Companies cited two reasons for these higher losses: (1) the predominant north-to-south power flow from Seabrook 1 would have to travel a longer distance over the Seabrook-Scobie-Tewksbury route (about fifty-five miles) than over the Seabrook-Tewksbury route (about forty miles) (Tr. IVA, p. 5; Exhibits 4-N-3 and 14-B-4); and (2) without the Seabrook-Tewksbury line, there would be higher current on the Seabrook-Scobie-Tewksbury route, since there would be only two paths for the power to flow out of Seabrook, which would produce higher loadings than would occur with three paths out of Seabrook (Exhibit 4-N-3; Tr. III, pp. 11-12; Tr. IVA, pp. 5-9, 20-21).

Since the Companies asserted that the differential losses would start in 1988, the year the Companies assumed the Scobie-Tewksbury line would be in service, and would end in 1990 when a second line would be built across the North/South Interface (something the Companies had scheduled to be tied with Seabrook 2) (Exhibit 29-B-9; Exhibit 51-N-13, pp. 15-16), the Companies calculated the value of differential line losses over three years. They estimated the present value of these three years of losses to be $3.1 million (Exhibit 17-N-11, Sch. ROB-14).

According to Mr. Bigelow, this estimate is conservative since the Companies do not expect Seabrook 2 to be completed in the foreseeable future and since the incremental line losses would continue as long as the construction of a second crossing of the North/South Interface continued to be postponed (Exhibit 51-N-13, pp. 15-16; NEES Brief, p. 21). Further, the line loss calculations do not reflect megavar loss costs which if included would have raised the line loss cost estimates (Tr. IVA, pp. 86-87).

iii. Economic Penalty Costs

Since the Companies assumed that the Scobie-Tewksbury line could not be completed until late 1988, they asserted there would be locked-in economic generation north of the Massachusetts border if Seabrook 1 went into operation and a new North/South Interface crossing were not in service. Locked-in low-cost generation north of the Massachusetts border would have to be replaced with higher-cost power generated in southern New England. The Companies used several planning dates for Seabrook 1's start-up to estimate how long these economic penalties would run and how much they would cost the region (Exhibit 17-N-11, pp. 22-29, 32-38, Sch. ROB-9, ROB-10, ROB-13, ROB-14).

The Companies used a computer model known as ECOPEN to simulate how NEPEX would dispatch the region's generating stations to meet certain load conditions, taking into account the presence or absence of a transfer limit (i.e., lack of a new transmission line) across the North/South Interface. The difference in production costs between two dispatches with and without a transfer limit is the gross economic penalty (Exhibit 17-N-11, Sch. ROB-9, ROB-10; NEES Brief, pp. 26-28).

According to the Companies, with Seabrook 1 on line in December 1984, the absence of a new transmission line would incur economic penalties in the range of $7 million to $17 million a year, depending upon assumptions about power plant performances. The present value of the Companies' expected penalty is $29.1 million for the Scobie-Tewksbury line and $0 for the Seabrook-Tewksbury line (since the Companies expect the latter can be in service at the time of Seabrook 1's start up) (Exhibit 17-N-11, Sch. ROB-9, ROB-13). The Companies estimated that with Seabrook 1 on line in July 1986, the annual economic penalty associated with the Scobie-Tewksbury line would range from $16 million to $31 million, with a present worth for the total expected penalty of $20.5 million (Exhibit 17-N-11, Sch. ROB-10, ROB-14); the economic penalty associated with the Seabrook-Tewksbury line would again be zero.

Mr. Bigelow asserted that these estimates were expected values, since with better than assumed performance of the generating stations, the total economic penalty could increase as much as 300 percent (Exhibit 17-N-11, p. 34, Sch. ROB-9), while unexpected summer outages of Seabrook 1 could reduce the penalty by $5 to $10 million a year (Id., Sch. ROB-10).

iv. Total Costs

The Companies argued that the same rationale that pushes for building a new line across the North/South Interface in conjunction with Seabrook 1 requires the Companies build the line that can be completed in sufficient time to avoid substantial economic penalties (NEES Brief, p. 26). According to the Companies, this line is the Seabrook-Tewksbury line, with a cost of approximately $27 million (in terms of the present worth of its total costs), as compared to $44 million to $52 million for Scobie-Tewksbury (Exhibit 17-N-11, pp. 38-39, Sch. ROB-13, ROB-14). The Companies explained that in spite of higher estimated construction costs for the Seabrook-Tewksbury line, its shorter distance and its ability to be built sooner than the Scobie-Tewksbury line give it a cost advantage, thus making it the line that must be constructed in a manner consistent with the construction program at Seabrook (Id., pp. 39-40; NEES Brief, pp. 12, 36-37).

2. NEPOOL's Position

As an "Interested Person" in this proceeding, NEPOOL supported the Companies' position that the Seabrook-Tewksbury line would provide a needed transmission link between Massachusetts and northern New England, and would enable New England to "avoid 'locked-in' sources of low-cost electricity in northern New England, a condition which violates both the public interest and specific NEPOOL standards" (NEPOOL Brief, p. 18). NEPOOL cited lower line losses and avoidance of economic penalties as benefits of the Seabrook-Tewksbury line that would outweigh its higher construction costs (Id., pp. 19-20). Finally, NEPOOL noted that "even Mr. Chernick...testified that the Tewksbury-Amesbury line is the less risky route and that a 'common cause' outage which could wipe out the entire Scobie-Tewksbury transmission corridor could be avoided by the construction of the Tewksbury-Amesbury line" (Id., p. 18).

C. The Intervenors' Criticisms of the Companies' Case

1. The Attorney General's Criticisms

While the Attorney General did not dispute the need for one line across the North/South Interface at some point in time, he questioned the Companies' conclusions that the Seabrook-Tewksbury line is necessary and is the least-cost alternative (Tr. I, pp. 115-116; AG Brief, p. 2). Specifically, the Attorney General asserted that the Companies' estimates of economic penalties and line losses associated with the Scobie-Tewksbury line are overstated due to the Companies' improper choice of key assumptions (Id., pp. 23-24, 33-35; Exhibit 47-AG-10).

Regarding economic penalties, the Attorney General argued that the period in which the Companies estimated economic penalties would run is overstated (Exhibit 47-AG-10, pp. 7, 36; AG Brief, pp. 14-17). He rejected the Companies' estimates of economic penalties commencing in December 1984, since even the Companies believe this is an unrealistically early in-service date for Seabrook 1 (Tr. V, pp. 97). The Attorney General also asserted that even a July 1986 starting date is faulty, because the Companies admitted in their Brief that a change to February 1987 would be appropriate (AG Brief, p. 16; Exhibit 63-AG-15). Further, he argued that the Companies' assertion of a 4.5-year lead time for Scobie-Tewksbury is too long and that economic penalties should terminate before the end of 1988 (AG Brief, p. 15; Exhibit 47-AG-10, pp. 36-37).

The Attorney General's witness, Mr. Chernick, also testified that the Companies used improper assumptions about the availabilities of northern generating units, as a result of including no summer outages for nuclear units, too-short refueling outages, and too-low forced outage rates (Exhibit 47-AG-10, pp. 8-17). According to the Attorney General, these availability assumptions would lead to overestimates of locked-in economic generation (Tr. V, pp. 56-68).

Further, Mr. Chernick stated that the Companies' use of NEPOOL's dated fuel price projections, rather than NEES' own more recent and lower fuel price forecast, meant that the Companies' estimate of economic penalties is too high (Exhibit 47-AG-10, pp. 17-23; AG Brief, pp. 20-23).

The Attorney General concluded that the Companies' economic penalty estimates are incorrect. The Attorney General offered several adjustments to reflect a later Seabrook 1 in-service date, an earlier Scobie-Tewksbury in-service date, the occurence of summer refueling outages in nuclear units, and NEES' fuel price projections (Exhibit 47-AG-10, pp., 19-23, 37; AG Reply Brief, pp. 5-12).

Regarding the Companies' calculation of line losses, the Attorney General's witness criticized the Companies' use of: non-representative load levels (Tr. V, p. 104); summer load conditions alone (Exhibit 47-AG-10, pp. 26-28); an inappropriate distribution of loads throughout New England (Id., pp. 26-28); and generation patterns that assumed too-high availabilities for northern nuclear units (Id., pp. 30-31) and, in particular, for Seabrook 1 (Id., pp. 32-34; Tr. V, pp. 53-54). The Attorney General also adjusted the Companies' line loss estimates to reflect use of NEES' fuel price projections and a lower capacity factor for Seabrook 1 (Exhibit 47-AG-10, p. 37). In the end, the Attorney General asserted that the Companies' estimates should not be relied upon at all (AG Brief, pp. 31; AG Reply Brief, pp. 2-4).

After modifying the Companies' estimates, the Attorney General's witness concluded that the two lines appear essentially equivalent in terms of their economics (Tr. V, pp. 138, 140, 145-146). Therefore, the Attorney General recommended to the Siting Council that it (AG Brief, p. 33; Exhibit 47-AG-10, pp. 38-39; AG Reply Brief, pp. 12-13):

(a) withdraw the original approval of the Amesbury-Tewksbury line because conditions on which it was based have failed to materialize;

(b) deny current reapproval of Amesbury-Tewksbury at this time, because of NEES' weak presentation;

(c) order NEES to proceed expeditiously with all critical path licensing activities for Scobie-Tewksbury;

(d) determine that NEES' planning process for the Scobie-Tewksbury and the Amesbury-Tewksbury lines was deficient; and

(e) require NEES to submit a complete case for the Seabrook-Amesbury-Tewksbury line at the earliest possible time.

2. Costello's Criticisms

Costello also criticized the assumptions the Companies used to calculate line losses and economic penalties, arguing that the Companies overstated the costs of the Scobie-Tewksbury line.

Costello argued that the Companies' line loss estimates are unreliable and too high due to: their improper assumption that the

Newington station is always running (Exhibit 46-C-7, pp. 6-9; Costello Brief, p. 41); and their "snapshot analysis" which used only a 90-percent summer peakload condition (Id., pp. 39-40). Costello asserted that the Companies' loss calculations can be neither accepted nor meaningfully adjusted, and recommended the Siting Council reject them entirely (Id., p. 41; Costello Reply Brief, pp. 5-7).

Concerning assumptions used to calculate economic penalties, Costello asserted the Companies used: lead-time estimates for Scobie-Tewksbury that were too long (Exhibit 22-C-60; Costello Brief, pp. 12-18); assumptions regarding Seabrook 1's in-service date and availability factors that were too optimistic (Id., pp. 19-25); an improperly high oil price forecast (Id., pp. 26-28); capacity factors that were too high and based upon unrealistically short refueling outage assumptions for northern nuclear plants (Id., pp. 29-36).

Costello also questioned the basis for the Companies' construction cost estimates for the Scobie-Tewksbury line (Id., p. 12-17).

On brief, Costello offered numerous adjustments to the Companies' cost estimates to reflect his arguments for using NEES' fuel price forecasts, higher-sulfur-content oil in those fuel prices forecasts, longer nuclear maintenance outages, delay in Seabrook 1 to mid-1987, a lower capacity factor for Maine Yankee, a Scobie-Tewksbury in-service date earlier than September 1988, summer outages of nuclear units, and a higher forced outage rate for Seabrook 1 (Costello Brief, pp. 9-37, A-2 through A-10; Costello Reply Brief, pp. 8-13).

While Costello offered specific adjustments, he concluded that the Companies' estimates were developed on the basis of such weak assumptions that the Siting Council should start from scratch to review the Companies' proposed transmission lines rather than base its decision on the intervenors' proposed adjustments to the Companies' case (Costello Brief, pp. 4-5).

Finally, Costello recommended adoption of the Attorney General's proposals, and further recommended that the Siting Council (Id., pp. 3-4):

(a) specifically find that the Companies' presentation has not been adequate to meet their burden of showing that their preferred line is indeed the better choice on economic grounds;

(b) require that, as a condition precedent to installing the Seabrook-Amesbury-Tewksbury line, they demonstrate it is clearly preferable on economic and environmental grounds; and

(c) consider, in another proceeding, the likely commercial operation dates for Seabrook 1, and its impact on transmission line requirements.

D. The Companies' Response to the Intervenors' Criticisms

In response to the intervenors' criticisms and arguments, the Companies adjusted their cost calculations but rejected most of the changes supported by the Attorney General and Costello.

1. Modifications Considered

The modifications proposed by the Companies include: an adjustment to the line loss calculation to reflect a 25-percent capacity factor for Newington Station (Exhibit 51-N-13, pp. 2-3, Sch. ROB-16); an adjustment to the economic penalty calculation to reflect an 8.5-week nuclear refueling outage (Id., p. 11, Sch. ROB-21); and an adjustment suggested on brief to modify economic penalty estimates to reflect a February 1987 date for Seabrook 1 (NEES Brief, p. 29, Appendix A).

Additionally, the Companies evaluated an adjustment to the economic penalty estimate to reflect the price differential between NEES' forecasted fuel prices and those used in ECOPEN (Exhibit 51-N-13, pp. 12-14, Sch. ROB-22; Exhibit 17-N-11, p. 28). However, after consideration, the Companies rejected this modification since they believe that all fuel price forecasts are uncertain, that both NEES' and NEPOOL's forecasts are within a reasonable range, and that the proper forecast to use for analysis of regional economic penalties is the one adopted consensually by NEPOOL members for estimating fuel prices for the region's generators (Tr. II, pp. 52-61; Exhibit 51-N-13, p. 12; NEES Brief, p. 34; NEES Reply Brief, p. 13).

2. Modifications Rejected

Changes suggested by the intervenors but opposed by the Companies include: reducing the construction cost estimate for Scobie-Tewksbury to reflect a higher level of transferable costs, since the Companies believe that they properly evaluated such costs (Tr. IVA, pp. 36-43; Exhibit 57-B-23); a shorter licensing and construction schedule for Scobie-Tewksbury, since they believe that their estimate is realistic (NEES Brief, pp. 29-31; Tr. II, p. 39; Tr. III, pp. 69, 107-113; Tr. IVB, pp. 51-52); a fifty-percent probability of summer outages of northern nuclear units, since NEPOOL schedules maintenance to avoid the summer and because the otherwise random probability of a summer outage would be twenty-one percent (Tr. III, p. 148-149; Exhibit 51-N-13, p. 12; NEES Brief, p. 33); a forty-eight-percent forced outage rate for Seabrook 1 in its early years, since NEPOOL assumes a forty-percent probability (Id., pp. 33-34; Exhibit 50-B-22, Sch. 7; Exhibit 51-N-13, pp. 10-11); a lower capacity factor only for Maine Yankee but not for Vermont Yankee, since the Companies believe NEPOOL's nuclear performance assumptions are sound on average (Exhibit 50-B-22, p. 6, Sch. 6, Sch. 8; NEES Reply Brief, p. 13); a wholly new line loss calculation to reflect more representative load and generation conditions, since the Companies assert their analysis is appropriate (Tr. II, pp. 198; Tr. III, pp. 8-9; Tr. IVA, pp. 26-28, 34; NEES Brief, pp. 20-25); eliminating the line loss calculation entirely, since the Companies contend that the laws of physics require that Seabrook-Scobie-Tewksbury will produce higher line losses than would be the case if Seabrook-Tewksbury were built (Exhibit 4-N-3; NEES Brief, pp. 18-19; NEES Reply Brief, pp. 9-10); and reconfiguring the proposed connection of the Seabrook-Scobie line at the Scobie bus, since the higher interconnection costs associated with that design would exceed the present worth of its line loss savings (Exhibit

51-N-13 Sch. ROB-17, ROB-18).

3. The Companies' Modified Case

The Companies ultimately conceded in their Brief that the Siting Council should rely on cost estimates based on a February 1987 planning date for Seabrook 1's start up (NEES Brief, App. A). The present value of the construction costs were $26.7 million for Seabrook-Tewksbury and $20.1 million for Scobie-Tewksbury, the same costs as had been projected for a July 1986 date for Seabrook 1.

The Companies proposed a differential regional line loss cost estimate for Scobie-Tewksbury based on the following assumptions: a February 1987 date for Seabrook 1 (Exhibit 64-N-14); ninety-percent summer peakload conditions (Exhibit 21-C-5; Exhibit 51-N-13, p. 2); NEPOOL estimates of forced outage rates and scheduled maintenance for northern generating units (Id., p. 3); a twenty-five-percent capacity factor for Newington (Id., pp. 2-3); cases which vary with respect to whether Seabrook and/or Newington are running (Id.; Exhibit 21-C-5, p. 1; NEES Brief, p. 20); and NEES fuel price forecasts (Exhibit 51-N-13, p. 3). According to the Companies, the present worth of the Scobie-Tewksbury line's differential losses from 1988 through 1990 is $2.2 million (NEES Brief, App. A).

The Companies asserted that the Scobie-Tewksbury line's economic penalties would occur during the period between Seabrook 1's start date (February 1987) and the in-service date of Scobie-Tewksbury (September 1988). According to the Companies, these economic penalties would have a present worth of $14.7 million. The Seabrook-Tewksbury line was estimated by the Companies to incur no economic penalties.

Further the Companies asserted that their cost analyses are conservative since: they reflect an optimistic licensing schedule for Scobie-Tewksbury (Tr. IVB, pp. 51-52); Newington's capacity factor after Seabrook's operation is expected to be fifty percent, rather than the twenty-five percent assumed (Tr. VI, pp. 7-8); the loadings on the lines crossing the North/South Interface could be higher in off-peak conditions than was assumed in the Companies' on-peak analyses (Tr. III, pp. 8-9); the ECOPEN results do not reflect any benefits associated with NEPOOL's interchange with New Brunswick (Exhibit 51-N-13, pp. 8-9); the line loss calculations do not include a capacity-cost component (NEES Brief, p. 22); and the loss costs are based on only a three-year period, even though the Companies expect higher losses would persist beyond that date since the Companies do not expect a second new line crossing the North/South Interface in the foreseeable future (Exhibit 51-N-13, pp. 15-16).

The Companies concluded that even with their proposed modifications, Seabrook-Tewksbury is the cheaper line. The Companies asserted that, even in light of changed circumstances, the Seabrook-Tewksbury line is still necessary in conjunction with Seabrook 1. They asserted that one line is needed to avoid locked-in economic generation in northern New England if: (1) Seabrook 1 came on line; and (2) a new transmission line across the North/South Interface were not in service. They prefer Seabrook-Tewksbury because it could be put into service in time for Seabrook 1 and would result in lower line losses every year until a second north/south line were completed. The Companies do not expect to construct this second line, the Scobie-Tewksbury line, until Seabrook 2 is constructed, which they do not anticipate in the near future. Therefore, the Companies believe that they are in compliance with the Siting Council's 1977 Order that Amesbury-Tewksbury, as part of the Seabrook-Tewksbury line, be constructed in a manner consistent with Seabrook 1 construction, and that Dracut-Tewksbury, as part of the Scobie-Tewksbury line, be constructed in a manner consistent with the construction of Seabrook 2 (NEES Brief, pp. 12-15).

E. <u>Findings with Regard to the Companies' Compliance with the Siting Council's 1977 Order in Light of Changed Circumstances</u>

The Siting Council must initially determine whether circumstances surrounding the Seabrook facility have changed since the 1977 Order. If the Siting Council finds that circumstances have changed, it must then determine whether the Companies have complied with its 1977 Order in light of those changed circumstances.

1. Changed Circumstances

The Companies provided evidence, undisputed by the intervenors, that one circumstance has not changed since 1977 -- that the North/South Interface needs reinforcement if Seabrook 1 comes on line so as to increase the transmission system's transfer capability in order to enable NEPEX to economically dispatch the region's generators while also meeting NEPOOL's reliability standards (Exhibit 17-N-11, pp. 19-20, 22-25; Tr. I, p. 115-116; AG Brief, pp. 2-3).

The Siting Council accepts the Companies' argument that additional reinforcement of the North/South Interface is needed if Seabrook 1 comes on line and that this rationale for a new transmission line has not changed since 1977.[6] Accordingly, the Siting Council finds that one relevant circumstance has not changed since the 1977 Order.

At the same time, however, the parties have demonstrated that: (1) Seabrook 2 has been indefinitely postponed and may never be built, and therefore the Seabrook project will at most be a one-unit nuclear facility; (2) Seabrook 1 would need only two transmission lines to connect it to the New England grid; (3) two transmission lines already have been built to connect Seabrook 1 to the grid; (4) the Seabrook-Tewksbury line is not needed specifically for the purpose of connecting Seabrook 1 to the grid; and (5) Seabrook 1 is not likely to be completed before February 1987 (Exhibit 15-AG-1, pp. 5-6; Costello Brief, pp. 6-7; Exhibit 17-N-11, pp. 17-25; Exhibit 64-N-14; Tr. III, pp. 22-24, 27).

Accordingly, the Siting Council finds that relevant circumstances have changed since 1977.

6/ The Siting Council's findings of fact in regard to the Seabrook 1 facility are strictly limited to the question of the Companies' compliance with the 1977 Order. Those findings which concern the operation of Seabrook 1 or a start-up date for that facility are reached for the sole purpose of reviewing the Companies' compliance with the 1977 Order. The Siting Council, however, makes no findings regarding whether or when Seabrook 1 will come on line.

2. The Companies' Compliance with the 1977 Order in Light of Changed Circumstances

The parties disagree on whether, in light of these relevant circumstances, the Companies are in compliance with the condition in the 1977 Order that they build the Amesbury-Tewksbury and Dracut-Tewksbury lines in a manner consistent with the construction program at Seabrook.

a. Need

In light of the findings above regarding changed circumstances since 1977, the Siting Council finds that the Seabrook-Tewksbury line is not specifically needed to meet federal licensing requirements regarding Seabrook 1's interconnection to the grid, as was the case in Docket No. 76-24. Further, the Siting Council finds that a new high-voltage, high-capacity transmission line connecting northern and southern New England is still needed to be built in conjunction with Seabrook 1.

The Companies and the Attorney General both testified that the Scobie-Tewksbury and Seabrook-Tewksbury lines are essentially equivalent in terms of their reliability and in satisfying the need for a north/south line to be built in conjunction with Seabrook 1. However, the Companies and NEPOOL asserted, and the Attorney General's witness conceded, that the Seabrook-Tewksbury line has slight reliability advantages over the Scobie-Tewksbury line because building a new line on the Seabrook-Tewksbury route would reduce the risk of a common-cause outage with other transmission lines that would share the Scobie-Tewksbury right-of-way (NEPOOL Brief, p. 18; Tr. V, p. 145).

The Siting Council finds that either the Seabrook-Tewksbury line or the Scobie-Tewksbury line would meet the need for a new 345 kV transmission line across the North/South Interface in conjunction with Seabrook 1's operation. The Siting Council further finds that the Seabrook-Tewksbury line has slight reliability advantages over the Scobie-Tewksbury line.

b. Cost

The Companies assert that they are in compliance with the 1977 Order since they plan to build only the lesser cost Seabrook-Tewksbury line in conjunction with the first (and perhaps only) unit of the Seabrook project. They argue that their studies show that the Seabrook-Tewksbury line is the appropriate choice since it has significant cost advantages over the Scobie-Tewksbury line in meeting the need for a new line across the North/South Interface in time for Seabrook 1's start up (NEES Reply Brief, pp. 6-7).

The Attorney General and Costello question this conclusion because they believe the Companies used improper assumptions in their cost analyses. The intervenors offered various modifications to the results of the Companies' analyses to reflect the intervenors' own assumptions. Ultimately, though, the Attorney General and Costello assert that the Companies' analyses are so flawed that the Siting Council should reject them *in toto*, rescind the 1977 Order approving the lines, and initiate a new review of the need for and cost advantages of the two lines.

In order to determine the issue of whether the Companies have complied with the Siting Council's 1977 Order in light of changed circumstances, the Siting Council must evaluate whether the Companies' plans to construct the Seabrook-Tewksbury line as the lesser-cost facility to meet the need for a new line across the North/South Interface in conjunction with Seabrook 1, are consistent with the Siting Council's 1977 Order.

i. Construction Costs

The first component of the cost analysis concerns construction costs. The Companies ultimately proposed that the Siting Council rely on a construction-cost estimate for the two lines that was relevant for either a mid-1986 or February 1987 start-up date for Seabrook 1 (Exhibit 17-N-11, Sch. ROB-14; NEES Brief, App. A). The Attorney General had argued that he did not expect Seabrook 1 to be in service before late 1986 or early 1987 (Exhibit 15-AG-1, App. p. 7). The

Siting Council finds that the difference between these two in-service date assumptions is within a reasonable range of error. Accordingly, the Siting Council finds the Companies' use of a February 1987 planning date for Seabrook 1 as the basis for developing a transmission-line construction cost estimate is reasonable.

According to the Companies' estimates, the present value of construction costs for the Seabrook-Tewksbury line was $26.7 million and was $20.1 million for the Scobie-Tewksbury line (Exhibit 17-N-11, Sch. ROB-14; NEES Brief, App. A). The Attorney General and Costello questioned elements of the Companies' construction cost estimate for the Scobie-Tewksbury line. However, the Attorney General and Costello did not quantify portions of the Companies' estimates which they believed should be changed in specific ways for specific reasons. Absent any affirmative evidence to use in place of the Companies' construction cost estimates for the Seabrook-Tewksbury and Scobie-Tewksbury lines, the Siting Council finds that the Companies' construction cost estimates provide a reasonable basis for determining which of the two lines is least cost. See Table 1.

ii. Line Loss Costs

In regard to line loss costs, the Companies' and Costello's witnesses agreed that line losses vary with the length and current resistance on transmission lines (Exhibit 4-N-3; Tr. I, pp. 41-43). Thus, for a given level and distribution of generation and load in a region, there would be higher losses for a transmission system with a longer line and with higher current than for one with a shorter line and lower current. The Companies testified that a NEPOOL grid with two interconnections to Seabrook would produce higher current on those interconnections than a system with three interconnections, all else being equal (Tr. III, pp. 10-12). Also, they provided evidence that in the absence of the Seabrook-Tewksbury line, the predominant north-to-south power flows in the region would have to travel both at higher current and over longer distance in a grid that included the Seabrook-Scobie-Tewksbury path, totalling fifty-five miles, rather than the Seabrook-Tewksbury path, totalling forty miles (Exhibits

4-N-3 and 11-B-1).

In that line losses vary directly with the length and with the square of the current of transmission lines, the Siting Council finds that for a given level and distribution of load in New England, current would be higher on lines in the proximity of Seabrook if the Seabrook-Tewksbury line were not built and there remained only two interconnections between Seabrook and the New England grid. The Siting Council also finds that the predominant north-to-south power flow across the North/South Interface would have to travel farther if the Scobie-Tewksbury line were built instead of the Seabrook-Tewksbury line. The Siting Council determines that the line loss differential between a system with only the Scobie-Tewksbury line and a system with only the Seabrook-Tewksbury line is greater than zero.

Mr. Bigelow and Dr. Graneau agreed that the full economic value of line losses should include both capacity and energy costs (NEES Brief, p. 22; Tr. I, p. 84)

The Siting Council accepts that line losses should be valued at their energy and capacity costs.

Accordingly, the Siting Council finds that there will be higher differential regional line losses associated with construction of the Scobie-Tewksbury line as opposed to the Seabrook-Tewksbury line, during the time when only one of those two lines is in service, and further that those losses will have economic value greater than zero.

The parties disagreed on the magnitude of these losses and what economic value the Siting Council should attach to them. According to the Companies' estimates, the present value of line losses from 1988 through 1990 is $2.2 million (NEES Brief, App. A). The Companies believe this is a conservative estimate because they actually expect losses to last beyond 1990 and the estimate includes neither megavar-loss nor capacity-component costs (Id., p. 22; Tr. II, pp. 176-177; Tr. IVA, pp. 86-87).

Costello did not dispute the methodology used by the Companies but did criticize the assumptions the Companies used to calculate line losses (Costello Brief, pp. 39-42). Although the Attorney General's witness suggested a modification to an early estimate (prepared by the Companies for a July 1986 Seabrook date) to reflect a lower capacity factor for Seabrook 1, in the end both the Attorney General and Costello recommended that the Siting Council completely reject the Companies' line loss estimates as unreliable (AG Brief, pp. 24-31; Costello Brief, pp. 38-39, 41).

Because the Siting Council has found that losses will be higher if Scobie-Tewksbury is constructed instead of Seabrook-Tewksbury and that these losses have economic value, the Siting Council cannot accept the intervenors' recommendation that the Siting Council reject altogether the Companies' line loss cost estimates.

Further, the Siting Council accepts the Companies' final estimate of losses (NEES Brief, App. A) as a reasonable approximation of the economic value of these losses, in light of the Companies' assertions that these estimates are conservative and the intervenors' assertions that the Companies' estimates overstate line losses.

Accordingly, the Siting Council finds the Companies' line loss estimates provide a reasonable basis for determining which transmission line is least cost. See Table 1.

iii. Economic Penalty Costs

The final cost component concerns economic penalties. The Companies argued that substantial economic penalties associated with locked-in generation in northern New England would occur if the Scobie-Tewksbury line, as opposed to the Seabrook-Tewksbury line, were the one built in conjunction with Seabrook 1. According to the Companies, these economic penalties with a present worth of $14.7 million could be avoided if Seabrook-Tewksbury were constructed in conjunction with Seabrook 1.

The Attorney General's witness criticized the assumptions that the Companies used to calculate economic penalties and offered modifications to the Companies' economic penalty estimate to reflect: a lower capacity factor for Seabrook 1; a longer maintenance period for northern nuclear units; a fifty-percent probability of a summer outage at Seabrook 1; use of NEES' fuel price forecasts; and the Scobie-Tewksbury line being built in 1986 or 1987 (Exhibit 47-AG-10, pp. 8-23). Taken together, these modifications resulted in total expected economic penalties amounting to approximately $3 million (Id., p. 37).

Costello also offered modifications aimed at changing the Companies' estimates. He identified the impacts on the Companies' estimates of assuming: the differential between NEES' fuel prices and those used in ECOPEN; delay of Seabrook 1 beyond 1987; a reduced capacity factor for Maine Yankee; an earlier in-service date for the Scobie-Tewksbury line; a twenty-percent probability of a summer outage at a northern nuclear plant; and a higher forced outage rate for Seabrook 1 (Costello Brief, pp. 9-37, A-2 through A-10).

The Siting Council agrees with the Companies' and Costello's assertions that the proper way to calculate economic penalties is through simulating the dispatch of the region's generating stations to meet forecasted load using scenarios that vary with respect to the existence of a transfer limit at the North/South Interface (Exhibit 51-N-13, pp. 12-13; Tr. II, p. 95; Costello Brief, p. 9). The Siting Council also notes that the Companies' ECOPEN estimates represent the only evidence developed through such a methodology. Accordingly, the Siting Council finds that the approach used by the Companies is an acceptable method for projecting economic penalties associated with a north/south transfer limit.

The Companies have argued that the economic penalties associated with the Scobie-Tewksbury line would begin in February 1987. The Companies have arrived at this date on the basis of their estimate of a "start-up" date for Seabrook 1. While the Siting Council makes no findings in regard to an operational date for Seabrook 1, it accepts the Companies' assumption for the purpose of evaluating the economic penalties associated with the Scobie-Tewksbury line.

Further, the Siting Council finds that a September 1988 in-service date for the Scobie-Tewksbury line is consistent with the transmission line construction cost estimates for the Scobie-Tewksbury line and the Seabrook-Tewksbury line that were previously determined by the Siting Council to be a reasonable basis for planning. Further, the Siting Council agrees with the Companies' position that their lead-time estimate for licensing and constructing the Scobie-Tewksbury line is realistic. Accordingly, the Siting Council finds that the September 1988 in-service date for the Scobie-Tewksbury line is a reasonable date to use for planning purposes for marking the end of the economic penalty period.

The Siting Council agrees with the Companies that projections of energy production costs in New England should be based on regional fuel price forecasts rather than fuel-price projections specific to an individual company. This would be a reason to reject the intervenors' claim that the Companies erred in using NEPOOL fuel price projections, rather than NEES', in the ECOPEN analyses. However, in this case, the Companies testified in response to the intervenors' questions that fuel price projections had dropped since the ECOPEN analyses (Tr. II, p. 53). Also, they stated that while both NEES' and NEPOOL's projections were within a reasonable range, current price projections were closer to those in the NEES projections (Id., pp. 53-54, 63-64). The Companies did not rerun ECOPEN and opposed use of NEES' fuel price forecasts, but offered a methodology that could be used to adjust ECOPEN's results to reflect the difference between NEES' and NEPOOL's fuel price projections. Costello supported this modification.

Absent a recalculation of economic penalties based on a more recent NEPOOL price projection, the Siting Council elects to use the NEES fuel price projection as a reasonable approximation of a more recent fuel price forecast for the region as a whole. Accordingly, the Siting Council finds that a modification of economic penalty estimates to reflect use of NEES' fuel prices is in order and that the methodology presented by the Companies is the one the Siting Council will use to modify the ECOPEN results (See Exhibit 51-N-13, Sch. ROB-22; Tr. VI, pp. 97-98; Costello Brief, p. A-2).

Further, the Siting Council finds that the intervenors failed to establish that their assumptions regarding the expected performance of selected generating units in northern New England were more reliable than the Companies' assumptions about the performance of unit types on average.

Accordingly, the Siting Council finds that the Companies' estimates of economic penalties, adjusted as noted above to reflect use of NEES' fuel price forecast, provide a reasonable basis for determining which transmission line is least cost. Therefore, the Siting Council finds that the present value of the Scobie-Tewksbury line's economic penalty is $12.8 million. See Table 1.

iv. Total Costs

Table 1 compiles the cost information determined above to be the reasonable basis for comparing the Seabrook-Tewksbury and Scobie-Tewksbury transmission lines. The present worth of Seabrook-Tewksbury is $26.7 million and of Scobie-Tewksbury is $35.1 million. Accordingly, the Siting Council finds that Seabrook-Tewksbury is the least-cost line.[7]

7/ The Siting Council notes that even if it had accepted all of the intervenors' proposed adjustments to the Companies' cost estimates for the Scobie-Tewksbury line to reflect no line loss differential and lower economic penalties, the Seabrook-Tewksbury and Scobie-Tewksbury lines would still be approximately equal in cost. If the Siting Council had eliminated Scobie-Tewksbury's line loss costs altogether, as proposed by Costello (Costello Brief, p. A-7), the present value of the total cost of the Scobie-Tewksbury line would have been reduced by $2.2 million (See Table 1). Further, if the Siting Council had accepted the Attorney General's or Costello's recommendations to assume a 50-percent probability of a summer outage for Seabrook 1 (Exhibit 47-AG-10, p. 37), a 48-percent forced outage rate for Seabrook 1 (Id.; Costello Brief, p. A-9), and a reduced capacity factor for Maine Yankee (Id., p. A-5), the present value of the Companies' estimate of economic penalties for the Scobie-Tewksbury line would have been adjusted by approximately $6.0 million (this reflects adjustments to the changes collectively indicated in Exhibit 47-AG-10, p. 37, and Costello Brief, pp. A-2 and A-5, so as to avoid double-counting the fuel-price modification the Siting Council made to the Companies' estimates to reflect use of NEES' fuel price forecasts). Thus, a total reduction by $8.2 million of the Companies' present-value estimate of the cost of the Scobie-Tewksbury line (see Table 1) would result in a net present value for Scobie-Tewksbury of $26.9 million, as compared to $26.7 million for Seabrook-Tewksbury. Therefore, a cost analysis incorporating the intervenors' assumptions still would not produce results showing the Companies' election to build the Seabrook-Tewksbury line is not in compliance with the 1977 Order. Further, any cost advantages that would have been shown for the Scobie-Tewksbury line would have had to outweigh the reliability advantages of the Seabrook-Tewksbury line.

The Siting Council finds that the Seabrook-Tewksbury line is the line needed to be built since it is the significantly less costly alternative to meet the demonstrated need.

c. The Companies' Compliance with the 1977 Order

The Siting Council notes that the Companies are pursuing construction of the Seabrook-Tewksbury line rather the Scobie-Tewksbury line in conjunction with Seabrook 1, because the Companies see the Seabrook-Tewksbury line as the lesser cost approach. Also, the Companies are deferring construction of the Scobie-Tewksbury line indefinitely.

The Siting Council finds that as long as the Companies are proceeding to build the line that will provide at minimum cost the reinforcement to the New England grid that would be needed in conjunction with Seabrook 1, then the Companies are in compliance with the Siting Council's condition in its 1977 Order.

Accordingly, the Siting Council finds that even in light of changed circumstances, the Companies are in compliance with the conditions in the Siting Council's 1977 Order that the Companies build the Amesbury-Tewksbury line in a manner consistent with the construction program at Seabrook.

V. WARRANTED MODIFICATIONS OF THE SITING COUNCIL'S 1977 ORDER

In light of the Companies' compliance with the Siting Council's 1977 Order, the Siting Council finds that no modification of that order is warranted.

VI. ORDER

The Siting Council hereby finds that the Companies are in compliance with the Siting Council's Order in Docket No. 76-24.

Robert D. Shapiro

Robert D. Shapiro
Hearing Officer

December 18, 1986

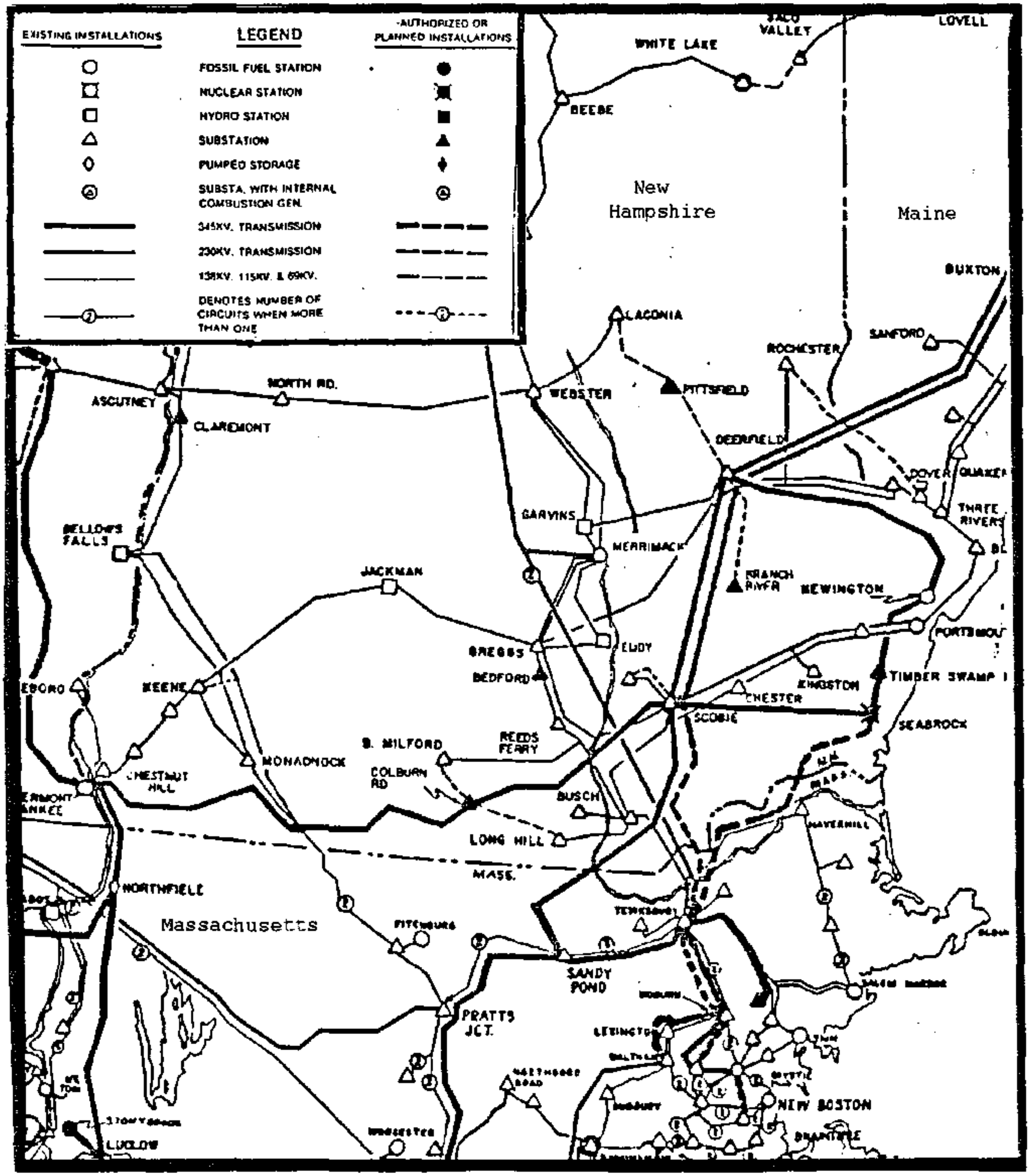
UNANIMOUSLY APPROVED by the Energy Facilities Siting Council at its meeting of December 18, 1986, by the members and designees present and voting: Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affairs); Joellen D'Esti (for Joseph Alviani, Secretary of Economic Affairs); Stephen Umans (Public Electricity Member); Joseph Joyce (Public Labor Member). Ineligible to vote: Acting Chair Dennis LaCroix (Public Gas Member); Elliot Roseman (Public Oil Member). Absent: Madeline Varitimos (Public Environmental Member). Recused from vote: Sharon M. Pollard (Secretary of Energy Resources).

12/19/86
Date

Dennis J. LaCroix

Dennis J. LaCroix
Acting Chairperson

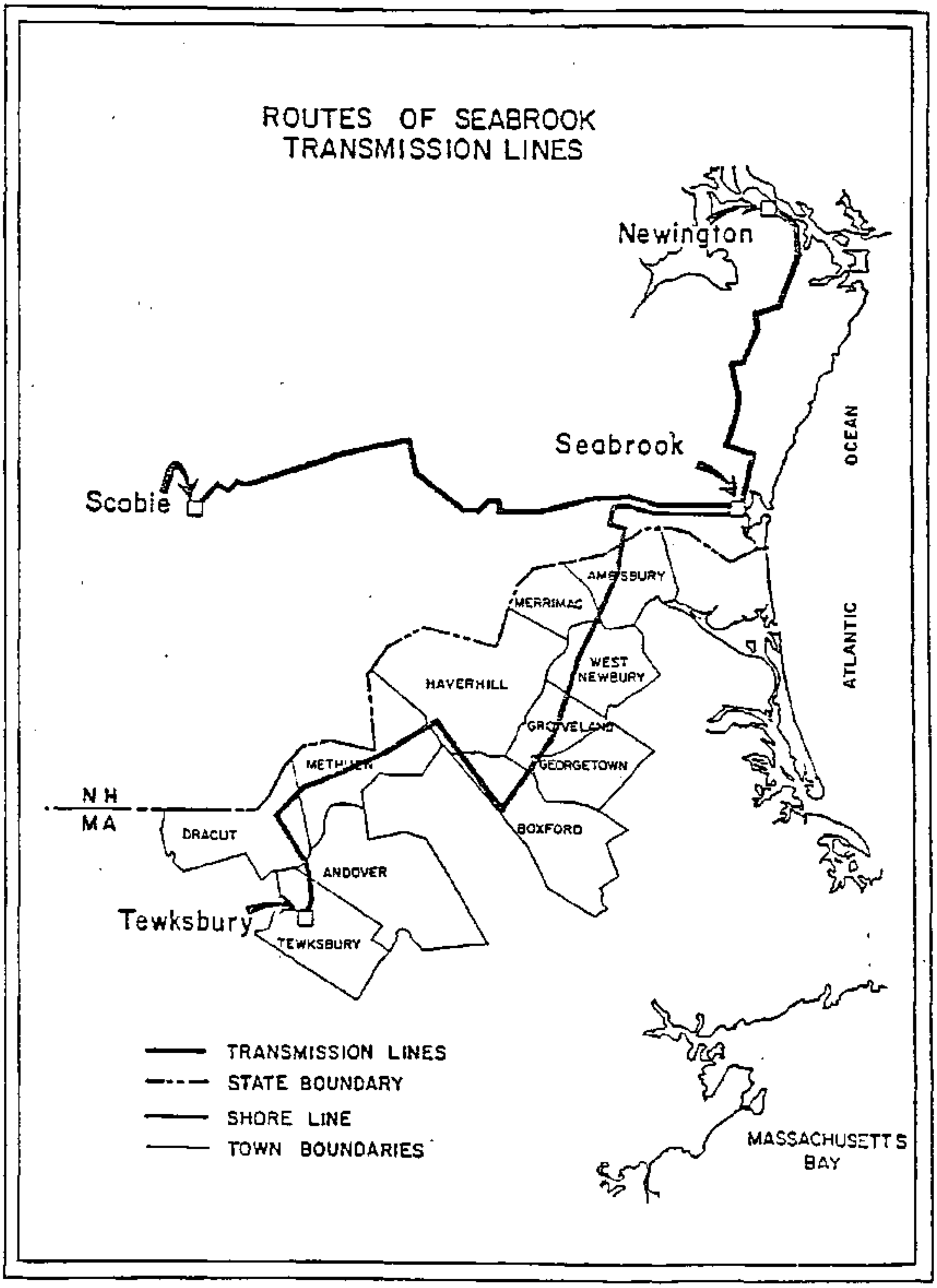
Figure 1
Map of New England Transmission System --
the Northeastern Massachusetts/Southern New Hampshire Section



Source: Exhibit 17-N-11, Sch. ROB-4

Figure 2

Routes of Seabrook Transmission Lines



Source: Exhibit 17-N-11, Sch. ROB-4

Table 1
Cost Comparison of the
Seabrook-Tewksbury and Scobie-Tewksbury Lines
(millions of dollars)

	(a) Constr. Costs (current $)	(b) Line Loss Costs (current $)	(c) Economic Penalties (current $)	(d) Total Costs (current $)	(e) Present Worth (1983 $)
Seabrook-Tewksbury Line					
sunk	$ 7.0	-	-	7.0	$ 7.0
1984	8.5	-	-	8.5	7.4
1985	9.2	-	-	9.2	7.0
1986	8.0	-	-	8.0	5.4
total	$32.7	-	-	$32.7	$26.7
Scobie-Tewksbury Line					
sunk	$ 7.0	-	-	7.0	7.0
1984	0.4	-	-	0.4	0.4
1985	2.4	-	-	2.4	1.8
1986	5.7	-	-	5.7	3.8
1987	11.3	-	10.6	21.9	12.9
1988	0.8	0.7	12.9	14.4	7.4
1989	-	2.1	-	2.1	0.9
1990	-	2.4	-	2.4	0.9
total	$27.6	$5.2	$23.5	$56.3	$35.1

sources and notes:

col. a - Exhibit 17-N-11, Sch. ROB-14; NEES Brief, App. A (revision of Sch. ROB-14). These costs include allowance for funds used during construction.

col. b - NEES Brief, App. A (modification of ROB-14 to reflect February 1987 date for Seabrook 1's commercial operation).

col. c - NEES Brief, App. A (modification of ROB-14, ROB-16, ROB-21). Modified also by Siting Council to reflect use of NEES' fuel prices according to method indicated in ROB-22 (see Tr. VI, pp. 97-98; Costello Brief, Table A-1).

col. d = (a) + (b) + (c)

col. e - present worth using NEPCo's 14.24 present worth factor (its weighted incremental cost of capital) (Exhibit 17-N-11, p. 33; Tr. IVB, pp. 52-55).

general assumptions: Seabrook 1 operational in 2/1987; Scobie-Tewksbury operational in 9/1988.

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Boston Edison Company for Approval of its Third and Fourth Supplements to its Second Long-Range Forecast of Electric Power Needs and Requirements (including the requirements of the Concord Municipal Light Plant and the Electric Division of the Wellesley Board of Public Works)	EFSC 85-12 (Phase II)

FINAL DECISION

Robert Shapiro
Hearing Officer
April 2, 1987

On the Decision:

Susan F. Tierney
Brian G. Hoefler

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The Energy Facilities Siting Council ("Siting Council" or "EFSC") hereby approves the demand forecast and rejects the supply plan as presented in the Third and Fourth Supplements to the Second Long-Range Forecast of Electric Power Needs and Requirements of Boston Edison Company including the requirements of the Concord Municipal Light Plant and the Electric Division of the Wellesley Board of Public Works.

I. INTRODUCTION

A. Description of the Company

Boston Edison Company ("Boston Edison," "BECO," or "the Company") is an investor-owned utility engaged in the generation, purchase, transmission, distribution, bulk power sales, and retail sales of electrical energy. In 1985, Boston Edison provided retail service to 40 cities and towns in the greater Boston metropolitan area and wholesale service to 23 customers, primarily municipal light boards.[1] Total electricity sold in 1986 was 11,685 gigawatthours ("GWh") (Exh. HO-158). BECO's sales account for about 30 percent of the retail electricity sold in Massachusetts. Boston Edison services

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1/Two municipally owned electric utilities, the Concord Municipal Light Plant ("Concord") and the Electric Division of the Wellesley Board of Public Works ("Wellesley"), receive almost all of their power requirements from Boston Edison. Sales to these two municipals in 1986 were expected to account for approximately 2.7 percent of BECO's total sales and 2.5 percent of summer peak load. Given the Company's obligation to supply virtually all of these municipals' power needs (Tr. II, pp. 59-60), their annual requirements and peak demands are included in the Company's forecast of total system demand. Consequently, the Siting Council's review of Boston Edison's demand forecast and supply plan also satisfies our mandate to ensure that Concord and Wellesley have sufficient resources to meet their requirements. Also, the Norwood Municipal Light Board ("Norwood") was a total requirements customer of Boston Edison until November 1, 1985. On that day Norwood began receiving its electricity from another supplier, thereby terminating all purchase agreements with Boston Edison (Exh. HO-3, p. H-1).

a largely urbanized area with a summer-peaking load and a high percentage (54 percent) of retail sales in the commercial sector.

In its review of Boston Edison's previous filing, the Siting Council conditionally approved the Company's demand forecast and supply plan. In re Boston Edison Company, 10 DOMSC 203, 250 (1984). In the conditions attached to that decision, the Siting Council ordered the Company to: (1) justify that its forecast's reliance upon old appliance usage data is appropriate; (2) report on the results of its conservation and load management ("C&LM") programs and integrate their expected long-run effects into its demand forecast; and (3) provide information on the status of its coal conversion and other fuel-diversification projects. The Company complied with all of these conditions, as discussed in Sections II.C.1, III.B., and III.H.

B. History of the Proceedings

On February 1, 1985, the Company filed the demand portion of its 1985 forecast (Exh. HO-1). On March 1, 1985, the Company filed the supply portion of that forecast (Exh. HO-2). In addition, the Company's supply plan included a proposal to build a 345 kilovolt ("kV") underground transmission line referred to as the Mystic-Golden Hills line (Exh. HO-2). The Company provided notice of the proceeding by publication and posting in accordance with the directions of the Hearing Officer.

On September 11, 1985, the Siting Council held a public hearing in Everett, Massachusetts, to receive comments regarding the proposed Mystic-Golden Hills transmission line. On October 10, 1985, the Hearing Officer issued a Procedural Order allowing the Siting Council to consider the transmission line proposal before reviewing the demand forecast and supply plan portion of the Company's filing. The Hearing Officer designated the facility review as Docket No. 85-12 (Phase I), and designated the review of BECO's demand forecast and supply plan as Docket No. 85-12 (Phase II). On November 18, 1985, the Siting Council conditionally approved the Company's petition to construct the Mystic-Golden Hills line. In re Boston Edison Company, 13 DOMSC 63 (1985).

On January 14, 1986, the Hearing Officer issued a Procedural Order directing the Company to file certain supplemental information in the instant proceeding, in lieu of submitting a complete forecast for 1986. On January 17, 1986, in accordance with the January 14, 1986 Procedural Order, the Company filed: (1) a supplement to its 1985 demand forecast (Exh. HO-3); (2) a detailed description of its planning process entitled "Capacity Planning: An Integrated Process" (Exh. HO-10); and (3) a three-volume report describing its conservation and load management programs entitled "Demand Planning Process: An Analysis of Forty Options" (Exhs. HO-5, HO-6, and HO-8). On February 21, 1986, the Company filed (1) a supplement to its 1985 supply plan (Exh. HO-4) and (2) a report detailing its supply planning process entitled "Long Range Supply Plan" (Exh. HO-9).

On September 9, 1986, the Hearing Officer issued a Notice of Adjudication, establishing October 14, 1986 as the deadline for petitions to intervene as a party and petitions to participate as an interested person. The Company provided notice of the proceeding in accordance with the directions of the Hearing Officer.

On October 10, 1986, the Massachusetts Audubon Society ("Audubon Society") filed a petition to participate as an interested person. The Company did not file an objection to the petition of the Audubon Society. On October 14, 1986, the City of Boston ("the City") filed a motion for an extension of time to intervene. On October 17, 1986, the Hearing Officer granted the City's motion for an extension of time to intervene. On November 3, 1986, the City filed its petition to intervene. On November 12, 1986, BECO filed its response to the City's petition to intervene. In a Procedural Order dated November 14, 1986, the Hearing Officer granted the City's petition to intervene and the Audubon Society's petition to participate as an interested person.

On November 21, 1986, the Siting Council conducted a pre-hearing conference to discuss: (1) the possibility of consolidating the Company's 1987 demand forecast and supply plan in the current proceeding; (2) the Company's objections to certain information requests; and (3) the schedule for the remainder of the proceeding. On December 5, 1986, the Hearing Officer issued a

Procedural Order stating that the Company's amended responses to certain information requests had obviated the necessity of merging the Company's 1987 demand forecast and supply plan with the instant proceeding.

On January 26, 1987, the Siting Council conducted a second pre-hearing conference to discuss: (1) establishing a date for filing the Company's 1987 forecast, as well as future forecasts; and (2) hearing and briefing schedules. At this conference, the Company was directed to address its concerns regarding future filing dates at the evidentiary hearing or in its brief.

Evidentiary hearings were conducted on February 12, February 17, and February 27, 1987. The Company presented four witnesses at the hearings: Robert A. Ruscitto, head of the demand planning division, who testified regarding the Company's conservation and load management programs; Richard S. Hahn, manager of the supply and demand planning department, who testified regarding demand forecasting, supply planning, and conservation and load management programs; Robert J. Cuomo, head of the forecasting and statistical analysis division, who testified regarding demand forecasting; and Jack F. Gurkin, head of the planning division, who testified regarding the Company's transmission and distribution systems. The Hearing Officer entered 168 exhibits in the record, largely composed of the Company's responses to information and record requests. The City entered 17 exhibits in the record.

Pursuant to a briefing schedule established by the Hearing Officer, the City filed its brief on March 11, 1987 ("City Brief"), and the Company filed its reply brief on March 18, 1987 ("BECO Brief").[2]

2/The Audubon Society did not present oral argument or file a brief.

II. 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 standards to demand forecasts: reviewability, appropriateness, and reliability.

A demand forecast is reviewable if the results can be evaluated and duplicated by another person given the same level of technical resources and expertise. A forecast is appropriate if the methodology used to produce that forecast is technically suitable to the size and nature of the utility producing it. A forecast is reliable if the methodology instills confidence that its data, assumptions, and judgments produce a forecast of what is most likely to occur. In re Boston Edison Company, 10 DOMSC 203, 209 (1984).

B. Demand Forecast Results

Boston Edison's two most recent demand forecasts have been reviewed in this proceeding -- one filed in February 1985 ("1985 Forecast") and one filed in January 1986 ("1986 Forecast") (Exhs. HO-1, HO-2, HO-3, and HO-4). The Siting Council has focused its review on the data and projections presented in the 1986 Forecast.

Table 1 summarizes key results of Boston Edison's 1986 demand forecast.[3] The Company expects its territory energy demand

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3/The 1986 Forecast projects requirements for the time period from 1986 to 2000. Since the Siting Council's enabling statute only requires electric companies to file forecasts (footnote continued) (excluding losses) to grow at a compound rate of 2.2 per cent per year over the forecast period and its summer peak demand to rise 1.7 percent annually[4] (Exh. HO-3, p. K-9).

C. Evaluation of the Demand Forecast

Since much of the Company's forecasting methodology has remained unchanged since the Siting Council approved that methodology in 1984, the Siting Council focuses its discussion here on: (1) the Company's compliance with the two conditions relative to the Company's demand forecast which were imposed by the Siting Council in its last decision; and (2) significant changes in the Company's methodology, data, and assumptions.

1. Compliance with Previous Demand Forecast Conditions

a. Appropriateness of EEI Data

In its most recent review of a BECO forecast filing, the Siting Council ordered Boston Edison to evaluate whether basing its appliance usage estimates on nationwide data collected by the Edison Electric Institute ("EEI") from as far back as 1971 continued to be appropriate.[5] The Company has provided evidence that it is

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(footnote continued) covering a ten-year time frame (G.L. c. 164, sec. 69I), the Siting Council has limited its evaluation to the time period from 1986 to 1995 ("forecast period"). Still, the Siting Council supports the Company's practice of preparing a forecast in excess of ten years.

4/Boston Edison is a summer peaking system. Although the 1985 Forecast projected a switchover to winter peaking by 1995 (Exh. HO-1, p. H-11), the 1986 Forecast indicates that Boston Edison now expects to remain a summer peaking system through 2000 (Exh. HO-3, p. K-11).

5/The issue of the appropriateness of EEI appliance data had been raised by the Siting Council as far back as 1982 in EFSC 81-12. In re Boston Edison Company, 7 DOMSC 93, 130-131 (1982).

undertaking two efforts to compile territory-specific appliance usage data for possible use in the residential forecast (Tr. II, p. 70).

In one of these projects, the Company has a residential appliance metering study that began in 1985 with a pilot test of 72 Boston Edison employees. The results of this pilot test were used to design a full-scale, year-long metering program which began in the summer of 1986 and should be completed by December 1987 (Exh. HO-3, p. E-4; Exh. HO-102). In the second project, the Company is participating with five other Massachusetts electric companies in a "Joint Utility Metering Project" ("JUMP") designed to meter directly the electricity usage levels and patterns of a sample of residential customers in each utility's service territory. This project is expected to yield data starting in December 1987 (Exh. HO-3, p. E-4).

The Company states that until the results of these studies are available, the EEI data are the best available to the Company (Exh. HO-102). The Company also reports it is unaware of any analysis suggesting that territory-specific usage would be significantly different from that reflected in nationwide data (Exh. HO-102). BECO reported on the results of a nationwide survey EEI conducted in 1982 to review industry research completed since 1977 on residential appliance consumption. According to BECO, this survey indicated that usage estimates (with the exception of those for microwave ovens) had not changed significantly and therefore EEI's 1971 data should remain unchanged (Exh. HO-3, p. E-4; Exhs. HO-102 and HO-129). In addition, the Company said it found that data from other sources, such as the Association of Home Appliance Manufacturers, Commonwealth Electric Company, Stone and Webster, and New England Power Pool ("NEPOOL"), are consistent with the EEI values (Exh. HO-102).

The Siting Council is satisfied that the Company is making progress toward obtaining territory-specific residential end-use data. The Siting Council finds that the recent survey conducted by EEI lends support to the Company's assertion that EEI's nationwide annual usage estimates are reasonable for BECO. While the EEI estimates are neither an ideal nor acceptable long-term data source, the data serve as an acceptable interim source while territory-specific data are accumulated. Further, in light of the evidence provided regarding

BECO's efforts to collect data through its own appliance metering study and through it participation in the JUMP study, the Siting Council finds that the Company is working to develop a reliable appliance consumption database for future forecasts and therefore has complied with the condition as set forth in the last decision.

b. Demand Management Application

In its 1984 decision, the Siting Council also ordered Boston Edison to prepare a report on the results of its demand management programs and to integrate the projected effects of those programs into its demand forecasts. The Company provided such information in detailed documentation and testimony (Exh. HO-3. pp. E-7, F-9, F-10, G-9, I-1 through I-7; Exh. HO-5, pp. 23-110; Exhs. HO-6, HO-7, HO-8, and HO-10; Tr. I, p. 65). The Company has adjusted its "natural" forecast of energy and peak load demand for the effects the Company expects to realize as a result of time-of-use rates ("TOUR") and Company-sponsored conservation and load management (Exh. HO-3, pp. E-23, F-27, G-11, I-32, J-19, J-22, and K-11). Accordingly, the Siting Council finds that Boston Edison has complied with this condition as set forth in the last decision.[6]

A comprehensive discussion of the Siting Council's evaluation of the Company's demand-management efforts is presented in Section III.G., infra.

6/In its 1986 filing, BECO complied with the Siting Council's previous order that the Company incorporate demand-management impacts into the results of the Company's long-range demand forecast. In its brief, BECO requested that the Siting Council reconsider imposing this requirement in subsequent filings: "[G]iven the treatment of conservation and load management programs as a 'supply' option, and the desirability of evaluating those programs on a parallel basis with other 'supply' resources, there is good reason to have a load forecast which has some degree of neutrality with respect to the choice of option[s] which will be used to meet the forecasted load" (BECO Brief, p. 11). The Siting Council agrees with the Company on this issue and directs the Company to present in its next forecast filing a demand forecast unadjusted for Company-sponsored C&LM programs and to use that unadjusted forecast in developing the Company's resource plans.

2. Methodological/Data Changes

Boston Edison's 1985 and 1986 Forecasts provide extensive, detailed documentation on the methods, data, and assumptions the Company used to develop those long-range demand forecasts (Exhs. HO-1 and HO-3). The Company explained a number of changes it introduced into its forecasting approach since the previous Siting Council review in 1984.

These changes include: a new econometric model to forecast various types and levels of employment in the Company's service territory, the results of which were used in forecasting energy use in the commercial and industrial sectors (Exh. HO-3, section D); a respecification of a migration model for the territory, the results of which are integrated with an estimate of natural population change to produce an estimate of the number of households in Boston Edison's service territory (Exh. HO-3, pp. C-4 to C-6); respecification of the regression models used to forecast the energy use of various SIC-coded industrial subgroups (Exh. HO-3, section G); integration of the effects the Company expects will result from price-induced and Company-sponsored demand-management programs into the demand forecasts of the residential, commercial, and industrial sectors (Exh. HO-3, pp. E-23, F-27, G-11, I-32, J-19, J-22, K-11); the use of the "HELM" hourly load model to forecast peak demand and to assess the impacts on demand of C&LM programs and TOUR (Exh. HO-3, section I); and analyses to determine the sensitivity of forecast results to changes in the assumptions regarding such variables as economic growth, electricity price, and weather, along with the development of a confidence interval around the Company's "baseline" forecast (Exh. HO-3, section J; Tr. II, pp. 54-57, 77-81; BECO Brief, p. 10[7]).

The Siting Council notes that many of these modifications, such as the respecification of the industrial regression equations, the

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7/In its brief, BECO cites several additional enhancements (BECO Brief, p. 12).

adoption of an hourly load model, and the preparation of sensitivity analyses, reflect changes encouraged by the Siting Council in previous decisions. In re Boston Edison Company, 10 DOMSC 203, 209-241 (1984). Others, such as refinements in the migration equation and the commercial end-use model and data, as well as the Company's stated intention to develop an industrial end-use forecasting model (Tr. II, pp. 67-69), are results of the Company's own initiatives in improving its demand forecasting.

The Siting Council accepts the methodological and data changes the Company introduced in its 1985 and 1986 forecasts as part of a generally reviewable, appropriate, and reliable forecasting approach.

3. Conclusions

Based on the record in this proceeding, the Siting Council finds that the Company has institutionalized a forecasting capability aimed at producing a well-documented, reliable demand forecast and at reducing the technical sources of forecasting error. In fact, the Company's demand forecast filing is exemplary in its level of documentation and could serve as a model for how other companies should document their filings to the Siting Council.

Based on the foregoing, the Siting Council finds that Boston Edison's 1985 and 1986 demand forecasts are based on substantially accurate historical information and reasonable statistical projection methods. The Siting Council also finds that the Company's forecasts are reviewable, appropriate, and reliable and, as developed and presented, provide the Company with a sound basis for making resource planning decisions. Accordingly, the Siting Council hereby unconditionally approves Boston Edison's 1985 and 1986 demand forecasts.

III. 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 a 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. In re Cambridge Electric Light Company, et al, 12 DOMSC 39, 72 (1985); In re 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. In re Cambridge Electric Light Company, et al, 15 DOMSC ___, 7 (1986). The Siting Council also evaluates whether a supply plan minimizes the long-run cost of power subject to trade-offs with adequacy, diversity, and the environmental impacts of construction and operation of new facilities. In re Boston Edison Company, 7 DOMSC 93, 146 (1982). The Siting Council's evaluation of the long-run cost of the supply plan generally focuses on a company's supply planning methodology. In re Cambridge Electric Company, et al, 15 DOMSC __, 10-12, 39-40 (1986). Finally, the Siting Council determines whether utilities treat demand management and power from cogeneration and small power production projects on the same basis as they treat new conventional power facilities and power purchases when those utilities attempt to develop an adequate, diverse, and least-cost supply plan.[8] In re Cambridge

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8/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.

Electric Light Company, et al, 15 DOMSC ___, 7, 27, 40 (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' supply plans 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. In re Cambridge Electric Light Company et al, 15 DOMSC ___, 7-9 (1986); In re Fitchburg Gas & 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 long-run. In re Cambridge Electric Light Company, et al., 15 DOMSC ___, 8 (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 can provide adequate supplies in the short run, that company must then demonstrate that it operates pursuant to a specific action plan guiding it in drawing upon alternative supplies should necessary projects not develop as originally planned. Id., pp. 8-9, 18-24, and 41. The Siting Council has defined short run as the period of time necessary to place the shortest-lead-time resource under a given company's control in service in a timely and cost-effective manner. The short-run may vary on a company-by-company basis. Id., pp. 8 and 18-19.

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 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 generating 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. 9 and 24-31.

B. Previous Supply Plan Reviews

The Siting Council raised two principal concerns regarding Boston Edison's previous supply plan. First, the Company's generation plans relied heavily on oil, and, second, the plan identified capacity shortfalls as early as 1990 but did not propose specific plans to avoid them. In re Boston Edison Company, 10 DOMSC 203, 241 (1984). The Company had indicated its efforts in general to address these issues through fuel diversification, conservation, and load management in its IMPACT 2000 program. Id., p. 249. As a condition to approval of its supply plan, the Company was ordered to present its plans for monitoring and evaluating conservation and load management programs[9] and to keep the Siting Council informed of the status of the Company's coal conversion projects and other approaches to diversifying its fuel mix. Id., pp. 246-247 and 250.

9/The Company's compliance with this Condition is addressed in Section II.C.1.b., supra.

Since that decision was issued in March 1984, the Siting Council has recognized and embraced a new competitive and dynamic supply environment. As a result, the Siting Council has recently allowed companies to show they have adequate supply plans in the long-run by demonstrating that they have adequate planning processes. Therefore, consistent with the Siting Council's long-run standard outlined in Section III.A., the Siting Council relaxes its previous requirement that the Company prove adequate supplies in the forecast years beyond the short-run.

In regard to Condition 3 of the previous forecast, the Company states that it is no longer planning to convert either the New Boston or the Mystic units to coal at this time (Exhs. HO-65, HO-83). The Siting Council is satisfied that Boston Edison has complied with that part of Condition 3 requiring reports on specific coal conversion projects. Compliance with the remainder of Condition 3 regarding fuel diversity is discussed in Section III.H., *infra*.

C. Supply Planning Methodology

Boston Edison describes its supply planning methodology as an iterative process involving generation planning, demand planning, and load forecasting functions (Exh. HO-10, p. 13; Tr. II, pp. 26-29, 71-72; BECO Brief, pp. 14-15). Inputs to the supply planning process include: the Company's load forecast; estimated effects of time-of-use rates and Company-sponsored demand-management; required reserve levels; fuel forecasts; available energy and capacity alternatives; estimated capital costs; actual and assumed operating characteristics; financial assumptions; and high and low bandwidths on key assumptions (load growth, fuel prices) (Exh. HO-10, pp. 13-16).

The Company states that in planning for both annual energy supplies and peak power capacity, it uses these inputs in two major programs to evaluate the data and produce a supply plan. The first program is the Electric Power Research Institute's ("EPRI") Electric Generation Expansion Analysis System model ("EGEAS"); the second is a production costing program developed by General Electric in 1968 which has since been enhanced by the Company as necessary (Exh. HO-10, pp.

17-18). Boston Edison uses EGEAS to develop its base expansion plan and to analyze the sensitivity of key assumptions. The Company states that the primary difference between its production costing program and EGEAS is that its own model uses an hour-by-hour load shape while EGEAS uses a load duration curve. Thus, the Company finds that its own program is more appropriate for calculating the projected avoided costs and marginal costs used in demand planning studies and cogeneration and small power production ("SPP") negotiations (Exh. HO-10, p. 18).

Pursuant to the order of the Massachusetts Department of Public Utilities ("MDPU"), 220 CMR 8.00 et seq., the Company has developed and begun to implement a process to incorporate cost-effective SPP and cogeneration purchase contracts into the Company's resource mix (Exhs. HO-12 and HO-13). Through this process the Company has established: a standard-offer contract; a "supply block" of new capacity the Company expects to need starting on a certain date; a power-purchase price based on the Company's long-run avoided energy and capacity costs that constitutes the ceiling price the Company may pay to SPP's and cogenerators for such power; and an auction process through which prospective developers may bid to receive the long-run energy and capacity payments for power they supply under their contract with Boston Edison (Id.).

To incorporate demand management into the Company's least-cost planning process, the Company has adopted a demand-management planning process which has included: a "needs assessment" of territory-specific end uses that offer the greatest demand-management potential; an identification of 40 specific techniques that have been implemented or studied by utilities elsewhere in the nation and that BECO could use to control customers' energy use and/or peakload demand; development of a methodology to analyze and compare those techniques according to their costs and benefits, where the value of benefits is measured in terms of the Company's long-run marginal energy and capacity cost; a ranking of those measures in terms of their expected net present value and their benefit/cost ratios; selection of a subset of the 40 measures for further risk assessment and for design as pilot programs; proposals to implement a set of six pilots; and current operation of three programs with six more designated for implementation in 1987. (Exhs. HO-5, HO-6, HO-7, HO-8, HO-9, HO-10, HO-137A, HO-140, HO-153, HO-154, and HO-159; Tr. I, pp. 61-64; Tr. II, pp. 155-157; BECO Brief, pp. 16-19.)

From various analyses based on these assumptions, models, and processes, the Company develops a base expansion plan that meets energy and power requirements. The Company states that this expansion plan serves as its operating plan and as the basis for determining the economics of demand-management and outside supply contracts. BECO states further that sensitivity studies provide the Company with a decision-making plan in the event of changes in its basic assumptions. The Company avers that this process "ensures that the Company will build generation facilities only when they are the most economic resource when compared to other options (supply and demand) on a standard basis" (Exh. HO-10, p. 19).

D. Supply Plan Results

1. Base Expansion Plan

The Company filed its "Long Range Supply Plan" ("1986 Supply Plan") in February 1986 (Exh. HO-9). The 1986 Supply Plan presents a base plan for generation expansion, sensitivity analysis for high and low load growth rates and high and low fuel price estimates, and an assessment of cogeneration and SPP potential. The base expansion plan for the expected load growth rate and fuel price forecast is presented in Table 2.[10]

10/BECO notes that it analyzes capacity additions in 100-MW increments to avoid biases due to unit size. However, the Company states that if it were to build a coal, combined-cycle, or any other intermediate class unit, it would most likely build in larger sizes to take advantage of economies of scale. Typical sizes might be on the order of 400 MW for a coal unit and 300 MW for a combined cycle unit. Still, the Company asserts that its supply planning assumption of 100-MW capacity additions is valid because new construction projects involving larger generating units could be undertaken as joint ventures with other utilities (Exh. HO-9, p. 7).

The Company makes a number of assertions about its supply plans (Exh. HO-9, pp. 1-2, 40-41):

- o Life extension of existing fossil-fuel units is economical in all scenarios.
- o Short- or long-term purchases are sufficiently economical to recommend relying entirely on purchases thereby deferring any Company construction beyond the Siting Council's ten-year planning horizon.
- o Combustion turbine and combined cycle generating units are planned for any necessary Company generation. Coal-fired units are only economical in the case of high fuel prices.
- o The first generation addition is planned for 1988 in the base plan, but as early as 1987 for the case of high load growth and as late as 1991 for low load growth.
- o The capacity mix is generally constant with respect to load growth changes, but very sensitive to fuel price changes.
- o The Ocean State Power purchase is economical in all cases.

2. Recommended Expansion Plan

While the Company states that its base expansion plan is its operating plan, it also states that it prefers a generation expansion plan different from the base plan. This recommended plan involves no Company construction and instead relies entirely on purchases from cogenerators, small power producers, independent power producers, and other utilities. See Table 3.

Boston Edison states that the recommended plan differs from the base plan in that: (1) BECO should purchase short-term capacity immediately since even though additional capacity is not needed until 1988, fuel savings are sufficient to make purchases economical; (2) the Company should purchase another 100 MW in 1988 and defer Ocean State Power by one year; and (3) the net present value of the recommended plan is $15 million less than the base expansion plan (Exh. HO-9, p. 21).

3. Sensitivity Analysis/Contingency Analysis

Boston Edison performed analyses which showed that changes in growth and fuel price assumptions cause changes in the Company's least-cost supply plan. The Company analyzed a total of nine scenarios -- each combination of base, high, and low growth rates and base, high, and low fuel price estimates -- in its 1986 Supply Plan (Exh. HO-9, pp. 18-36). See Table 4.

All of the Company's sensitivity studies also analyzed the impacts on the Company's supply plan associated with loss of either or both of the Company's planned purchases from new but as yet unconstructed supply projects: the Ocean State Power Company combined cycle power plant ("Ocean State" or "OSP") in Rhode Island and the Pt. Lepreau 2 nuclear plant ("PL 2") in New Brunswick.[11]

4. Updated Supply Plan

Since Boston Edison's supply plan is continuously evolving, many changes have occurred since the Company's supply plan was filed in February 1986. Therefore, the record in this case includes the Company's supplemental information requests which enables the Siting Council to review supply plan modifications through the close of hearings (February 27, 1987) in this proceeding.

Recent changes in the supply plan include Boston Edison's negotiation of a new 250 MW, five-year purchase agreement with Northeast Utilities ("NU") under which the Company began receiving supplies on November 1, 1986 (Exh. HO-55). An additional 150 MW purchase from NU is under active negotiation (Tr. II, p. 150). Changes also involved the numerous proposals by cogenerators, SPP's,

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11/The Company's original base case included a purchase from Pt. Lepreau 2 even though the Company stated that it assumed PL 2 was "indefinitely deferred" (Exh. HO-9, p. 3). The Company treated loss of PL 2 as a contingency in its sensitivity analysis (Exh. HO-9). The Siting Council will also assume PL 2 is indefinitely deferred.

and independent power producers to sell power and energy to the Company. The Company has signed contracts with eight of those suppliers,[12] the largest of which is the 90 MW (summer capacity[13]) Ocean State purchase. Since those contracts were signed, the Company issued its Request for Proposals ("RFP") soliciting up to 200 MW of cogeneration and SPP to be added by 1991 (Exhs. HO-12 and HO-13). As of the close of hearings in this proceeding, the response to this solicitation was not yet known. One other significant change is NEPOOL's implementation of its Performance Incentive Program ("PIP") (Exh. HO-33). PIP has substantially modified the Company's capability responsibility[14] and established a policy of meeting summer capability responsibility with summer generating unit ratings.

Boston Edison's supply plan is compared to the Company's capability responsibility and summarized in Table 5. The Siting Council will evaluate this supply plan in its determination of adequacy of supply.

12/Although the Company has signed contracts with eight suppliers, only four of those eight contracts have been approved by the MDPU. Hereinafter, those four contracts are classified as "approved" while the four contracts not yet approved by the MDPU are classified as "likely."

13/Since Boston Edison is a summer peaking system and NEPOOL plans to implement a program for relying on summer capacities during the summer period (Exh. HO-33), the Siting Council will discuss Boston Edison power projects in terms of their summer capacity ratings.

14/For instance, 1988 summer reserve requirements were originally forecast at 13.4 percent (Exh. HO-9, p. 14), but later recalculated at 22.1 percent (Exh. HO-157B) primarily due to PIP implementation.

E. <u>Adequacy of the Supply Plan</u>

In accordance with the Siting Council's previously articulated standard of review, Section III.A., <u>supra</u>, Boston Edison's supply plan is evaluated in terms of its ability to meet resource requirements in both the short run and the long run.

1. <u>Adequacy of Supply in the Short Run</u>

a. Definition of Short Run

A company's short-run forecast period is defined as the time required to implement the first resource under that company's direct control to meet the projected need for new capacity. The Company asserts that its shortest-lead-time resource would be a combustion turbine and that combustion turbines take approximately 3.5 years to place in service (Exhs. HO-57 and HO-75). Accordingly, the Siting Council finds that Boston Edison's short-run period is one to four years (through summer 1990).

b. Short-Run Options

The City contends that the Company has no short-run supply options for meeting any short-run deficiencies (City Brief, p. 25). However, the Company asserts that it would handle any supply deficits by applying its planning process to look at alternatives and evaluate them accordingly (Tr. I, p. 106). Alternatives include a new 76 MW summer capacity (85 MW nominal) combustion turbine ("CT") peaking unit in Walpole, Massachusetts and purchases from other utilities (Tr. I, p. 109; Tr. II, pp. 145-151; BECO Brief, pp. 22-23). The Siting Council will evaluate the Company's options to determine whether it can reasonably rely upon them to meet its short-run deficits.

The Walpole combustion turbine is a Company construction project with an expected lead time from formal site study to start-up of 3.5 years (Exh. HO-57). However, this project falls within the short run because of an attempt by the Company to "prelicense" the facility by completing all pre-procurement and pre-construction phases prior to establishing a need for the facility in an identified year (Exh. HO-58; Tr. I, pp. 89-90; Tr. II, pp. 114-115). The Company believes prelicensing serves as a "hedge against uncertainties associated with load growth and anticipated future power purchases" (Exh. HO-58).

The Company expects that prelicensing specific facilities at specific sites will reduce the total lead time for each particular facility. In the case of combustion turbines, the Company expects to reduce the lead time from about 3.5 years to about 1.5 years after the time that need for a given facility has been established (Tr. I, p. 89). The Company has estimated that, assuming all necessary permits are obtained by May 1, 1987, the Walpole facility could be available by November 1988 (Exh. HO-78).

Since the Walpole CT is the Company's first attempt at prelicensing, the concept and process has yet to be tested before all permitting agencies. The record in this proceeding neither supports nor refutes the Company's ability to prelicense the Walpole CT so as to enable start-up as early as November 1988. However, for the Siting Council's analysis of the Company's supply plan, the Siting Council finds that it is reasonable to assume that the Walpole CT could be on line by summer 1989.

The Company has also begun internal background work for the prelicensing of a combined cycle ("CC") generating unit. A CC unit could be built in stages, first as a combustion turbine, then later adapted as a combined cycle plant. Staged construction would mean that BECO could begin receiving power as early as 3.5 years after the formal planning process would have begun. However, since the Company could not clearly indicate progress on its schedule for completing prelicensing activities, the Siting Council must conclude that the lead time for the first stage of any CC units remains 3.5 years[15]

15/The Walpole combustion turbine is being licensed as a combustion turbine only; it cannot be adapted at any later date to operate as a combined cycle plant (Tr. I, p. 108).

(Tr. I, pp. 112-118). Thus, at this time, the Siting Council finds that the Company cannot reasonably rely upon combined cycle plants for contingency plans to meet any short-run capacity needs.

The second short-run alternative is outside purchases -- in particular, a 150 MW purchase from Northeast Utilities. The NU purchase is readily available since it is already on line and planned for retirement unless purchasers are found (Tr. II, pp. 150-151). Mr. Hahn, the Company's supply planning witness, stated that such a purchase would serve as an "insurance policy" against certain contingencies (Tr. II, p. 167). As of February 17, 1987, Boston Edison and NU were in "the final stages" of negotiation (Tr. II, pp. 197-198).

The City argued that, since Mr. Hahn could not state the specific generation characteristics of the 150 MW NU purchase and since Mr. Hahn also indicated that the Company is not relying on this purchase in its analysis, the 150 MW NU purchase should not be considered as a short-run option (City Brief, pp. 19-20). The Siting Council rejects the City's contention that the NU purchase is not a realistic option. According to the Company, the capacity is already available, negotiations have made significant progress, and the cost is within reason (Tr. II, p. 167). Although Mr. Hahn stated that the Company is not yet relying on the 150 MW purchase, he made it clear that short-term purchases are a preferred Company short-run option.

During the course of this proceeding, an application of the Company's planning process emerged. The Company's 1986 supply plan indicated supply deficits in each year beginning in 1988 (Exh. HO-9, p. 14). As required by the Siting Council's standard for short-run adequacy, the Company filed an action plan for addressing these deficits including the necessity of securing a 100 MW short-term purchase for the period 1987-1990 (Exh. HO-9, p. 3). Such a 100 MW purchase would have provided the necessary capacity to meet the projected deficits. The Company further stated that, if it could not negotiate a purchase by year-end 1986, it would proceed with construction of a 100 MW combustion turbine to be in-service by

1988.[16]

The Company did indeed secure a short-term purchase -- the five-year, 250 MW purchase from NU beginning November 1, 1986. The Company's ability to secure that power supply conforms with the Siting Council's intent that companies have both reasonable planning flexibility and adequate supplies.[17] The purchase also lends support to the Company's assertion that it can secure another 150 MW purchase from NU to meet the presently forecasted 1988 and 1989 deficits.

Accordingly, the Siting Council finds that the Company can reasonably rely upon a 150 MW purchase from NU as a short-run option.[18]

Nevertheless, we question the adequacy of the Company's contingency plans in the event that a short-term purchase could not be found; that is, we question the Company's plan to construct a new CT to be in service before the summer of 1988. The first CT that could

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16/The Company deserves to be commended for the clear format it used to present its supply situation, action plans, and contingency plans in Exhibit HO-9.

17/The changes to the Company's supply plan that precipatated deficits despite the 250 MW, short-term NU purchase are primarily increased reserve requirements and decreased summer capacity ratings, both due to PIP implementation (BECO Brief, pp. 22-23).

18/In its decision in EFSC 86-4, the Siting Council ruled that Cambridge Electric Light Company, Canal Electric Company, and Commonwealth Electric Company ("COM/Electric") could not reasonably rely on purchase offerings from NU without more concrete evidence of COM/Electric's ability to contract for such offerings. In re Cambridge Electric Light Company, et al., 15 DOMSC ___, 21 (1986). The record in that proceeding showed that COM/Electric was not actively pursuing negotiations and could not provide details of any purchase arrangements. In the instant proceeding, however, Mr. Hahn testified in detail about the Company's on-going negotiations with NU including testimony about availability, pricing, and timing. Thus, the Siting Council finds significant differences in the relative positions of Boston Edison and COM/Electric in securing an NU purchase agreement.

be available, the Walpole CT, could not be in service any earlier than November 1988 (Exh. HO-78). Without an outside purchase, the Company would experience deficits in 1988 even under base conditions.

The Siting Council cannot accept planning flaws that leave companies vulnerable to short-run deficits. However, in this particular case the Company has identified readily available capacity and has shown (albeit only once) that similar capacity can be added in a timely manner. The Siting Council suggests that, in future filings, the Company should file contingency plans that are reasonably practical.

As another short-run option, the Company stated that, if the Seabrook I power plant comes on line, there may be excess capacity from that plant available for purchase from companies such as Eastern Utilities Associates ("EUA") (Tr. I, p. 109; Tr. II, pp. 149-150). However, since EUA "won't have anything to sell until [Seabrook I] comes on line" (Tr. II, p. 149), and substantial uncertainty surrounds the Seabrook I on-line date (Tr. II, p. 199), the Company has not initiated any detailed purchase discussions (Tr. II, p. 149). The City noted that, even if Seabrook I does come on-line within the short run, the Company could not indicate the amount of power that would be available (City Brief, p. 19). In that BECO was unable to provide more specific information on purchase quantities and pricing, or a reasonably clear timetable, the Siting Council finds that the Company failed to establish that Seabrook I capacity could be relied upon as a short-run option.

In its brief, the Company asserts that the substantial uncertainty surrounding an on-line date for Seabrook I has other implications for the adequacy of Boston Edison's supplies in the short run (BECO Brief, p. 23). Since Seabrook I represents a large capacity addition to NEPOOL but not to Boston Edison,[19] start-up of the plant would increase the Company's reserve margin without direct addition of

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19/The Company is not a participant in the Seabrook I power project.

supplies. Therefore, a delay in Seabrook I start-up also delays the Company's increased reserve margin.[20] But since BECO could not possibly be considered to have reasonable control over Seabrook I start-up, the Siting Council finds that such a delay cannot be considered as an option for the Company in meeting any short-run contingencies.[21]

Therefore, the Siting Council finds that the Company has a short-run action plan with two elements: (1) a 76 MW combustion turbine available prior to the summer of 1989; and (2) a 150 MW purchase from NU available prior to the summer of 1987.

c. Base Case Plan/Recommended Plan

Assuming all new supply projects materialize as planned and load growth at base growth rates, Table 5 shows that the Company should have adequate short-run capacity during 1987 and 1990, but may be capacity deficient in 1988 by 94 MW (2.8 percent) and 1989 by 62 MW (1.9 percent). Since the Siting Council requires companies to prove adequate capacity in the short run, Boston Edison must prove it can obtain supplies to avoid the short-run deficits in 1988 and 1989.

The 1988 and 1989 deficits are "in essence ... sole justification" for the 150 MW NU purchase currently under negotiation (Tr. II, p. 197). Such a purchase would more than adequately meet the deficits in each year. If the Company continues to prelicense the Walpole CT, it could be on line in time to meet the 1989 deficit, although it could not be available in time to meet the 1988 deficit. If Seabrook I is delayed beyond the summer of 1989, the Company would

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20/In the event of a Seabrook I delay, the Company's summer peak reserve requirements under a base load growth rate would be unchanged in 1987, and decreased by 94 MW in 1988, 83 MW in 1989, and 72 MW in 1990 (Exhs. HO-157B and HO-157C).

21/Since a Seabrook I delay would affect the Company's capability responsibility, the Siting Council examines those effects where appropriate.

have no deficit in 1988 and a surplus of 21 MW in 1989. Therefore, the Siting Council finds that Boston Edison has sufficient short-run options to meet its short-run base case deficits.

d. Short-Run Contingency Analysis

In order to establish adequacy in the short run, a company must also establish that it can meet a reasonable range of contingencies. To evaluate the adequacy of the Company's short-run supply plan, the Siting Council analyzes three contingencies: (1) simultaneous delay of the three largest new supply contracts, (2) a high load growth rate, and (3) loss of Pilgrim capacity credit. A summary analysis of these contingencies is presented in Table 6.

i. Simultaneous Delay of the Ocean State, Northeast Energy, and Everett Energy Projects

By 1990, the Company plans to add three new, relatively large outside supplies totalling 252 MW: Ocean State Power at 90 MW, Northeast Energy Associates ("Northeast Energy" or "NEA") at 82 MW, and Everett Energy Corporation ("Everett Energy") at 80 MW. Of those three projects, only Ocean State has not yet been approved by the MDPU. The Company stated that postponement of all three of these projects beyond the short run is a reasonably likely contingency. The Company, however, has not prepared plans for that particular scenario (Tr. I, pp. 105-106).

If all other independent supply projects progress as expected, postponement of these three projects would cause a capacity shortfall of about 74 MW below the expected 1990 summer peak.[22] One option the Company has for avoiding this deficit is to construct the 76 MW Walpole combustion turbine which would be sufficient to meet this

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22/Since these projects are scheduled for addition after the summer of 1989, 1990 is the only short-run year affected by this contingency.

deficit. Also, the possibility of a 150 MW purchase of NU capacity would more than adequately meet this contingency.

Accordingly, the Siting Council finds that the Company has established that it has an action plan for securing the necessary supplies to meet requirements in the short run in the event of simultaneous delays in the Ocean State, NEA, and Everett Energy projects.

ii. High Load Growth

The Company's short-run supply plan must also be capable of adapting to a higher than expected load growth rate. The Company filed a high load growth forecast in which load would grow at a compound rate of 2.5 percent from 1986 to 2010 compared to a compound growth rate of 1.7 percent in the base case (Exh. HO-9, p. 22). In the short-run, the Company acknowledges need for capacity in every year in order to meet such growth (See Tables 4 and 6).

Table 6 shows that, in 1987 and 1990, the 150 MW NU purchase would be sufficient to meet the need for additional capacity in the high load growth scenario. However, in 1988 and 1989, that purchase could be required to avoid the base case deficits (see Sec. III.E.1.c, supra), so high load growth would require additional capacity beyond the 150 MW NU purchase. If the Walpole CT is also built, the Company still would have 1988 and 1989 shortfalls of 117 MW and 30 MW, respectively. Even assuming a delay in Seabrook I with the associated decrease in the Company's expected reserve margins, the Company could not meet the potential 1988 deficit.

The high load growth contingency plan filed in February 1986 suggested adding three 100 MW combustion turbines, one each in 1987, 1988, and 1989 (Exh. HO-9, p. 33[23]). Yet the Siting Council has

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23/This particular reference is to the case of high load growth under base fuel prices. Due to the drop in world oil prices during the spring of 1986, fuel prices are much closer to the Company's low fuel price forecast (Tr. I, p. 123). However, for high load growth in the short run, the contingency plans under base and low fuel prices are virtually identical (See Table 4).

already found that, since the Company requires 3.5 years to site, license, construct, and prepare a combustion turbine for start-up, the only possible short-run CT option is the Walpole CT which could be on line by the summer of 1989. See Section III.E.1.b, supra. Unless the Company is already pursuing the licensing of three additional CT's, an action not supported by this record, this contingency plan would clearly fail to meet high load growth in the short run.

Although demand management options may have added considerable flexibility into plans for adapting to load growth uncertainties, the Company has not demonstrated an ability to evaluate the cost effectiveness of demand-side options under various load growth scenarios (See Section III.G, infra). Boston Edison's bias toward generation options in its design of its short-run action plan has led the Company to a situation where it must rely on load growth rates lower than its own high growth forecast.[24] This basic flaw in the Company's supply planning process has unnecessarily exposed Boston Edison's customers to possible supply shortages if growth exceeds base expectations.

A company must demonstrate that its supply plan is sufficiently flexible to meet a reasonable range of contingencies. This range of contingencies is not limited to delay or loss of expected supplies, but also includes uncertainties such as changes in load-growth or fuel-price forecasts. Boston Edison has not demonstrated such flexibility.

Accordingly, the Siting Council finds that the Company has failed to establish that it has an action plan capable of securing the necessary supplies in the short run to meet the Company's high load growth forecast.

24/The City suggested that one of the Company's plans for improving its potential capacity deficits would be to hope for lower than expected peak load growth (City Brief, p. 20). While Mr. Hahn stated that lower than expected load growth would fall into the category of "positive contingencies that are of sufficient magnitude that they could mitigate the problem [of capacity deficits]" (Tr. II, p. 148), the Siting Council does not construe this categorization to be one of the action plans put forth by the Company.

iii. Loss of Pilgrim Capacity Credit

An issue raised during the proceeding was whether or not the current Pilgrim nuclear power plant shutdown constitutes a contingency. The Company asserted that, since it expects to continue to receive Pilgrim capacity credit until the time Pilgrim resumes generation, no contingency planning is necessary (Exhs. HO-16, HO-17; Tr. I, pp. 147-149). The City of Boston argued that the issue is not whether Pilgrim will remain operable beyond a reasonable doubt, but instead whether there is a reasonable possibility that the Company will not have Pilgrim at its disposal (City Brief, p. 22). The City stated that "BECO should be facing squarely the very real possibility of losing its Pilgrim capacity credit," and that the Siting Council should "recognize that BECO should have put forward ... an action plan for the loss of the Pilgrim capacity credit" (City Brief, p. 21).

To determine the rules governing capacity credit loss, various NEPOOL standards were introduced into the record. Since Pilgrim generation is dispatched by NEPOOL, Pilgrim is subject to NEPOOL Operating Criteria, Rules and Standards ("CRS"). CRS No. 4 (Exh. HO-152) specifies NEPOOL's requirements for the uniform rating and periodic audit of generating capability, and therefore it governs Pilgrim capacity credit (Tr. I, pp. 140-141, 152). Under this CRS, generating units, including Pilgrim, "must regularly achieve claimed capability....Units having unsatisfactory availability will be subject to deratings by the [NEPOOL Operations Committee]" (Exh. HO-152, p. 1). To verify claimed capabilities, NEPOOL conducts capability "demonstrations" (sometimes called audits) for all centrally dispatched generating units in both a summer period and a winter period (Exh. HO-152, p. 3). Failure to demonstrate full capability during two consecutive like demonstration periods results in a derating to a capability "no greater than the highest capability demonstrated in the two (2) like Demonstration Periods" (Exh. HO-152,

p. 12).[25]

Pilgrim last passed such a capability demonstration in the spring of 1986 (Tr. I, p. 135). Thus, Pilgrim has missed passing one summer and one winter capability demonstration. Failure to pass its summer audit by September 15, 1987, the end of the 1987 Summer Demonstration Period, will result in loss of Pilgrim's summer capacity credit during the 1988 Claimed Capability Period; failure to pass its winter audit by February 29, 1988, the end of the 1987-88 Winter Demonstration Period, will result in loss of Pilgrim's winter capacity credit during the 1988-89 Claimed Capability Period. Mr. Hahn acknowledged that he is aware the Company will lose Pilgrim capacity credit if it does not pass its capability demonstrations during the summer of 1987 and the winter of 1987-88 (Tr. I, pp. 138-140).

Mr. Hahn, however, testified that Pilgrim could regain its capacity credit for the summer of 1988 if Pilgrim came back on line as late as May of 1988 (Tr. I, p. 153-154; BECO Brief, p. 23). The Company failed to estalbish that CRS No. 4 supports such an allegation.

While it is unnecessary for the Siting Council to make a determination as to whether or when Pilgrim will return to operation, the possibility of losing Pilgrim capacity credit is a contingency that merits attention in the Company's contingency planning process. Indeed, the Company's most recent estimate of when Pilgrim will resume generation is the end of June 1987 (Tr. I, p. 133), just two and

25/NEPOOL differentiates between "Claimed Capability Periods" and "Demonstration Periods." These periods are defined in CRS No. 4 as follows:

	Claimed Capability Periods	Demonstration Periods
Summer	June 1 - Sept. 30	July 1 - Sept. 15
Winter	Oct. 1 - May 31	Nov. 1 - Feb. 28 (29)

A NEPOOL member must demonstrate its capability during the Demonstration Period and that demonstrated capability is effective during the Claimed Capability Period. (Exh. HO-152, pp. 2-3) one-half months before a failure to demonstrate Pilgrim's 666.6 MW summer capacity credit[26] would result in loss of that credit during the 1988 summer period.[27] Therefore, the Siting Council finds that the Company should be planning for the contingency of Pilgrim capacity credit loss.

The short-run supply impact of a possible loss of Pilgrim capacity credit is summarized in Table 6. Even under the most optimistic contingency scenario, the Company's current action plan is not adequate to meet the loss of a generating unit as large as Pilgrim. In any short-run year that Pilgrim capacity credit were lost, capacity deficiencies would occur, reaching a deficit of 589 MW in 1988.[28] Applying the Company's short-run action plan options (see Section III.E.1.b, supra) could possibly reduce the 1988 deficit to 439 MW.

The Siting Council cannot expect utilities to routinely maintain enough firm backup capacity to support the sudden loss of a unit as large as Pilgrim. As the Company correctly notes, a regional power pool serves that function to some degree by pooling back-up resources and enabling members to avoid holding extremely large quantities of backup capacity in reserve (Exh. HO-17). Indeed NEPOOL's operating rules provide for granting two full years of capacity credit to those who must suddenly shut down major facilities. It would seem that this two-year period balances a member company's need for time to plan replacement supplies with NEPOOL's need to move back to full and reliable generation capability.

26/Pilgrim's current summer capacity credit is 666.6 MW (Exh. HO-4, p. I-8). Boston Edison sells 172 MW to other utilities (Exh. HO-48) leaving 494.6 MW that the Company would lose from its supply plan.

27/CRS No. 4 provides for a derating to a capability no greater than the highest capability demonstrated during the last two demonstration periods. Pilgrim has not generated any power since the spring of 1986; thus, the highest demonstrated capability is zero.

28/Although BECO's portion of Pilgrim capacity amounts to 495 MW, the base case deficit in 1988 contributes another 94 MW.

During the course of this proceeding the Company was asked to provide its contingency plans specifically for the possibility that Pilgrim did not come back on line as the Company expected (Exhs. HO-16, HO-17). The Company stated that it had not prepared such plans, would not prepare such plans, and instead deemed delays in the resumption of Pilgrim generation of a year or more as not "sufficiently likely to warrant preparation of a formal plan" (Exh. HO-16).

The Company provided a glimpse of its preparation for a Pilgrim capacity credit loss in the following policy statement:

> If for some reason Pilgrim no longer qualified for capacity credit, the Company would seek short term purchases looking both inside New England and outside of New England. The availability and costs of such purchases are unknown at this time.
>
> It is unlikely that Qualifying Facilities that are not already under contract or in service would be able to come on line in less than 3 - 5 years. The Company could also pursue additional conservation and load management that would not otherwise be cost effective. However, it is unlikely that this would amount to a significant amount in a 3 - 5 year period and certainly not in the 500 MW range.
>
> Barring the availability of sufficient C&LM, additional QF facilities or additional purchases, the Company would in all probability proceed with the licensing and construction of approximately 500 MW of combustion turbine and combined cycle capacity. The minimum lead time would be about 5 years and could conceivably be considerably longer.
>
> Given the magnitude of the capacity lost and the relatively tight capacity situation within NEPOOL as a region, it is unlikely that capacity deficiencies could be avoided, especially in years 1 - 5. (Exh. HO-17)

The Siting Council cannot consider this sort of vague and speculative statement to be either an indication of responsible resource planning or a specific action plan to address the contingency. The Company acknowledges that loss of Pilgrim capacity credit would pose an enormous problem for the Company which, we would assume, lends additional incentive to study such a loss. Sufficient uncertainty surrounds the Company's ability to count on Pilgrim's capacity credit in the short run to make it imperative that the Company show it is asking and attempting to answer "What would Boston Edison do if..." types of questions.

During testimony Mr. Hahn was asked when the Company itself would find it necessary to develop contingency plans. He stated that when the Company became "convinced it would lose [Pilgrim capacity credit] for a period of time that would be long enough to justify going out and securing a replacement" (Tr. I, p. 141), it would begin looking for replacement supplies. The witness offered no discernable, relevant explanation as to when the Company might be "convinced" that Pilgrim could cause a capacity deficiency prompting the Company to begin developing contingency plans.

The Siting Council cannot accept or abide the Company's rationale for determining that its Pilgrim situation does not yet merit development of a formal contingency action plan. The Company provided no evidence that it has explored in any detailed fashion the consequences of a Pilgrim capacity credit loss. The Company has not even indicated that it is asking "what-if" questions, much less proceeding with the necessary background work for development of contingency plans.

Accordingly, the Siting Council finds that the Company has failed to establish that it has an action plan capable of securing the necessary supplies in the short-run to meet the contingency of loss of Pilgrim capacity credit.

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 1991 through 1995. Of these long-run forecast years, the Company indicates summer deficiencies beginning in 1992 (See Table 5).

As previously stated in Section III.A, *supra*, the Siting Council does not require electric companies to prove adequate supplies in long-run years as long as a company demonstrates that its planning process can identify and fully evaluate a reasonable range of supply options. The ability of Boston Edison'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.G., infra.

3. Conclusions on the Adequacy of Supply

In that the Company has failed to establish that it has an action plan capable of securing the necessary supplies in the short-run to meet either (1) its high load growth forecast or (2) the loss of Pilgrim capacity credit, the Siting Council finds that the Company's supply plan fails to ensure adequate resources to meet customer requirements.

F. Adequacy of the Transmission System Planning

1. The Company's Position

a. The Company's Transmission Plans and Planning Process

In its 1985 filing, Boston Edison identified and discussed certain problem areas in its transmission system (Exh. HO-2, App. B). One of these problem areas was described by the Company as the "Northern Tie" problem (Exh. BOS-14, p. 1), which the Company proposed to resolve by constructing a 6.3-mile 345 kV transmission line between the Company's Mystic Station power plant in Everett, and BECO's Golden Hills substation in Saugus (Exh. HO-2, pp. II-2, II-18, App. B). The Company's plan to resolve the Northern Tie problem was the subject of Phase I of the instant proceeding. The Siting Council conditionally approved the Company's petition to construct the Mystic-Golden Hills line (See Section I.B., supra). In re Boston Edison Company, 13 DOMSC 63 (1985).

The Company's 1985 and 1986 filings also identified an "area supply problem" relating to the Company's expectation that Boston Edison's existing and planned transmission system in downtown Boston will be inadequate to meet customer requirements in the event of certain contingencies starting in 1992 (Exh. HO-2, pp. II-19; Exh. HO-4, pp. II-18). The Company stated that this problem would arise that year even assuming the Company were allowed to construct an underground 345 kV transmission line from Mystic Station to a new 345/115 kV substation near the Company's existing Kingston Street substation in the financial district of downtown Boston (Exh. HO-2, pp. II-15, II-16). This "Mystic-Downtown" line[29] was conditionally

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[29]/The 345 kV transmission line approved by the Siting Council in 1977 was actually proposed to run between Mystic Station and a new 345/115 kV substation on Lincoln Street in Boston's financial district. The in-service date for (footnote continued)

approved[30] by the Siting Council in 1977, with the line originally planned for completion by 1985. In 1985, in its decision on Phase I of the instant proceeding, the Siting Council approved a new, 1989 in-service date for the Mystic-Downtown line. In re Boston Edison Company, 13 DOMSC 63, 82 (1985). As of the conclusion of hearings in this proceeding, the line was not yet under construction (Tr. III, p. 14).

At the request of the City of Boston, the Company sponsored a witness, Mr. Gurkin, to testify in regard to BECO's transmission system planning process. According to Mr. Gurkin, the Company's planning process includes: (a) a forecast of substation-specific load growth forecasts prepared by BECO's Forecasting and Statistical Analysis Division,[31] (Tr. III, pp. 10-11, 31-32, 40-45; Exhs. BOS-5, BOS-6); (b) use of load flow studies to analyze the adequacy of the Company's transmission system in response to a range of generation and transmission contingencies (Tr. III, p. 15); (c) identification of problem areas where the transmission system does not perform

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(footnote continued) this line was projected at the time to be 1985. In re Boston Edison Company, 2 DOMSC 58, 60 (1977). Due to the proximity of the originally proposed Lincoln Street substation and the now-planned substation near the existing Kingston Street substation, the Siting Council, in Phase I of this proceeding, considered the Mystic-Lincoln Street line to be the same as the Mystic-Kingston Street line for purposes of the Siting Council's review process. Hereinafter, this line will be referred to as the "Mystic-Downtown" line or the "Mystic-Kingston" line.

30/These conditions required that: (a) by 1978, the Company provide to the Siting Council an updated in-service date for the line; (b) "because type of construction, exact location, and ultimate design have not been finally determined for the above lines, any party or state or local governmental agency may negotiate or enter into agreements with the Company as to matters of final design, engineering, and construction;" and (c) the Company notify the Siting Council of final costs for the project. In re Boston Edison Company, 2 DOMSC 58, 63-63 (1977).

31/This Division of BECO's Supply and Demand Planning Department prepares the Company's short-run and long-run energy and load forecasts (Tr. III, pp. 10-12), as discussed in Section II.

adequately (Tr. III, p. 10); and (d) preparation of analyses evaluating and recommending approaches to resolving specific system performance problems (Id.).

b. The Downtown Boston Transmission Problem

In response to the City's questioning, Mr. Gurkin testified as to the Company's planning specifically with regard to what the Company has identified as the "Downtown Problem" (Tr. III, pp., 19-23, 51; Exh. BOS-14, p. 1), which the Company states it has planned to resolve through installation of the Mystic-Downtown line (Exh. HO-2, pp. II-15 to II-19).

Mr. Gurkin explained that in 1983, the Company first realized that by the late 1980s, if the Company did not reinforce its existing 115 kV transmission system,[32] Boston Edison would have to disconnect (i.e., "shed load" or "black out") customers in parts of downtown Boston at certain peak load periods and under certain generating and transmission conditions[33] (Tr. III, pp. 58-59, 102-103). In May

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32/In 1976, when Boston Edison asked the Siting Council to approve the Mystic-Downtown line, the Company asserted that the line was need to transport to the Boston area the power produced at the then-proposed Pilgrim 2 in Plymouth. The Siting Council approved the need for the line in 1977. In re Boston Edison Company, 2 DOMSC 58, 60, 63 (1977). Construction of the line did not begin thereafter. Mr. Gurkin testified that in 1981, Boston Edison cancelled its plans to construct Pilgrim 2 (Tr. III, pp. 55). He stated that the downtown transmission problem the Company identified in 1983 related to the expected inability of the Company's existing 115 kV transmission system (i.e., without the approved but as-yet unconstructed 345 kV Mystic-Downtown line) to import power southward to Boston from generating sources north of metropolitan Boston (Tr. III, pp. 55-57).

33/This analysis assumed outages of both units of the New Boston powerplant, and a "most reasonable scenario" forecast of load growth in the five principal downtown Boston substations (Tr. III, pp. 44; Exh. BOS-6). This forecast indicated 4-percent growth per year and was based on an analysis of new construction projects planned for downtown Boston; this forecast indicated faster growth than the 1.6-percent annual load growth projection for the entire BECO service territory (Exh. BOS-13).

1984, Boston Edison issued a report indicating that: due to faster than expected load growth, this potential problem could occur as early as 1987/88;[34] and "exposing the core city area to the risk of significant load disconnection two or three times a summer is unacceptable" (Exh. BOS-14, p. 8). The report recommended a plan to resolve the problem (Exh. BOS-14; Tr. III, pp. 58-59) through: (a) installation of phase-angle regulating transformers in 1988; (b) reconductoring existing lines in 1986 and 1987; (c) building a 345/115 kV autotransformer in downtown Boston (near the financial district) in 1988; (d) installing the first cable of a Mystic-Downtown 345 kV transmission line in 1988; and (e) installing a second cable and autotransformer around 1995 (Exh. BOS-14, pp. 1-4).

Mr. Gurkin testified that the first cable of the new Mystic-Downtown transmission line has been authorized by Boston Edison management, but the second has not yet been approved (Tr. III, p. 62; Exh. HO-4, pp. II-13, II-17). The Company stated that it has requested permits and approvals for the facilities from various state and local agencies, and has received several required permits and approvals (Tr. III, pp. 67-68; Exh. BOS-15; BECO Brief, pp. 26-29). The Company's planned in-service date for the first Mystic-Downtown line is June 1989 (Exh. HO-4, p. II-13).

Mr. Gurkin testified that in the interim, certain parts of downtown Boston might have to be blacked out during summer peakload periods in 1987 and 1988 if certain "double contingency" conditions occur (Tr. III, pp. 66-69, 90-102, 107-108). Boston Edison's evidence indicates that in order to avoid overloading its lines, the Company would have to shed load during the summer of 1987 at any time the Company's system load reaches 2080 MW (i.e., 79 percent of projected

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34/At the start of this study in 1983, BECO projected its 1990 system peak demand would be above 2450 MW -- the level at which the Company estimated load shedding would have to occur if the 115 kV transmission system were not reinforced. The May 1984 report indicates that while the study was being prepared, the Company revised its demand projections and estimated the 2450 MW level would be reached by 1987/88 (Exh. BOS-14, p. 6).

peak, a load level that BECO expects to occur on 40 of the 120 summer days) and both units of the New Boston generating station are out (which BECO expects to occur on two of the 120 summer days, based on historical averages) (Exhs. BOS-10, BOS-11, BOS-12, BOS-16). For the summer of 1988, Boston Edison's evidence shows that the load-shedding threshold would be 2000 MW (i.e., 75 percent of projected peak, a load level the Company expects to occur on 60 out of the 120 summer days) (Exh. BOS-11).

The Company also states that during the 1987 and 1988 summers, if the Company's existing Mystic-K Street 115 kV transmission line goes out of service at the same time both New Boston units are out, the load shedding threshold would be lower and could be expected to be reached on more than ninety percent of the summer days in 1987 and 1988 (Id.). In this "worst case scenario" (as characterized by the Company), up to twenty-five percent of Boston Edison's customers could be blacked out (Tr. III, pp. 98-100; DPU 86-255, Exh. BE-36, p. 6; BECO Brief, p. 29).[35]

Mr. Gurkin testified that if any of these double-contingency or worst-case conditions occur in the summer of 1987 or 1988, Boston Edison will have to black out certain parts of the Boston area by sequentially disconnecting specific circuits on certain substations on its downtown transmission system until the Company's load is adequately reduced to avoid overloading the line(s) (Tr. III, pp. 70-76; Exhs. BOS-9, BOS-10). According to Mr. Gurkin, BECO customers in South Boston, Roxbury, Jamaica Plain, the South End, and Dorchester are served by the substations identified for disconnection if contingencies occur (Tr. III, p. 73). Mr. Gurkin testified that these areas have been selected for engineering reasons, since these areas

35/BECO estimates worst-case planning scenarios based on a "base-case" condition which assumes a certain amount of generation already out of service and then looks at the effect on the transmission system of the next two contingencies (Tr. III, pp. 118-119; DPU 86-255, Exh. BE-36, p. 6). BECO asserts that the probability of losing an underground transmission line is three orders of magnitude less than the probability of a generating unit going out of service unexpectedly (Exh. BOS-11).

are served by radial lines, which are easier to disconnect than lines on networks (such as those serving downtown Boston) (Tr. III, pp. 75-76).

Mr. Gurkin also testified regarding several interim measures the Company has taken to improve the reliability of the existing Boston transmission system before the Mystic-Downtown line is completed (Tr. III, pp. 108-112). The Company shows that, based on internal recommendations made in late 1983 and spring 1984, the Company has installed a forced cooling system and a heat-sensing cable monitoring system on parts of the downtown transmission system (Tr. III, pp. 108-109, 112, 121-122; Exh. BOS-17). The Company asserted that it "recognized that required reinforcements could not be built before 1989 and it moved quickly to implement these interim actions in order to minimize potential adverse reliability impacts on customers in the downtown area" (BECO Brief, pp. 33-34).

In conclusion, the Company argues that it "has adequately planned to meet the energy supply requirement of its customers in the City of Boston" (Id., p. 25). Furthermore, the Company asserts that a Siting Council review of the Company's supply plan is not the proper forum for investigating the "Downtown Problem" since the instant proceeding does not involve a request for approval of facilities (Id., pp. 25-34).

2. The City of Boston's Position

The City of Boston asserts that Boston Edison "cannot provide a necessary energy supply to the City of Boston" since "the Boston Edison Company, through its own fault, has placed the City of Boston in severe jeopardy of blackouts in 1987 and 1988" (City Brief, p. 1).

The City avers that the Company has known for at least four years that the City of Boston is likely to have a blackout two or three times during the summer of 1987 and more often during the following summer (Id., pp. 1, 8-12). While the City acknowledges the Company's plan to add a forced cooling system and construct the Mystic-Kingston line, the City argues that these "solutions are both too little and too late" to resolve the impending problems in 1987 and

1988 (Id., pp. 3-4).

Citing the Company's evidence on the likelihood of a simultaneous outage of both units at New Boston and the likelihood that load levels would reach the load-shedding threshold if that contingency occured, the City asserts that the probability that customers in South Boston, Roxbury, Dorchester, and Jamaica Plain will be disconnected is 33 percent in the summer of 1987 and 50 percent in the summer of 1988 (Id., pp. 4, 12-15).

Finally, the City asserts that this situation "epitomizes BECO's abandonment of its public interest function" (Id., p. 4) and is endangering the public health, safety and welfare of the City for at least the next two years (Id., pp. 15, 23).

In regard to the Company's plans to resolve these problems by mid-1989 through the construction of new facilities, the City alleges that the Company has failed to seek approvals from all of the City's bodies that have statutory authority to grant permits required for the construction of the proposed Mystic-Downtown line (Id., pp. 7-8). Further, the City asserts that the Company has not complied with the 1977 condition imposed by the Siting Council in its approval of the Mystic-Downtown line that the Company enter into negotiations with state or local governments as to matter of final design, engineering and construction of the line (Id., p. 7). The City therefore questions whether "through untimely application by BECO,...BECO's 1989 solution may be delayed which, in turn, exposes the City to further risk of blackouts" (Id., p. 7).

The City urges the Siting Council to reject Boston Edison's filing as "incomplete, untimely and lacking in a specific remedial plan for action" (Id., p. 23).

The City also requests that the Siting Council direct BECO to: seek all outstanding approvals for the Mystic-Kingston line; submit to the Siting Council and the City detailed reports on a monthly basis concerning the Company's progress in obtaining all necessary approvals for all construction already identified as necessary to alleviate the downtown problems; and provide the Siting Council and the City with contingency plans specifically designed to alleviate the blackout conditions BECO concedes are likely to occur (Id., pp. 23-24).

Finally, the City asserts that since the statutory authority to require a company to fulfill its public interest obligations rests with the MDPU rather than the Siting Council, the Siting Council should ask the MDPU to investigate how BECO management allowed the summer 1987 and summer 1988 downtown Boston reliability problems to develop (Id., pp. 4-5, 23-24).

3. Evaluation of the Company's Transmission System Planning

a. Jurisdiction

The Company has argued that a review of the adequacy of its transmission system is not appropriate in this proceeding. BECO asserts that the sole issue before the Siting Council is the adequacy of the Company's demand forecast and supply plan (BECO Brief, pp. 25-26).

The Siting Council rejects the Company's assertion that this proceeding is an improper forum for addressing issues relating to the adequacy of the Company's transmission system planning and plans. In considering these transmission issues in the current review of the Company's long-range supply plan, the Siting Council is clearly fulfilling its statutory mandate.

First, the Siting Council's statute explicitly ties companies' ability to commence construction of facilities to Siting Council determinations as to whether those facilities are consistent with the most recently approved long-range forecast or supplement thereto. G.L. c. 164, sec. 69I.

Secondly, G.L. c. 164, sec. 69I requires companies to file descriptions of actions they plan to take which will affect their ability to meet their customers' electric power needs and requirements. These descriptions are required to include plans for constructing facilities and for reducing requirements through load management. In accordance with this statutory scheme, the Company presented the Mystic-Golden Hills transmission line proposal as part of its 1985 long range forecast (Exh. HO-2, Sec. II). Although the facilities proposal was ultimately severed from the complete filing in order to expedite its review, Boston Edison Company, 13 DOMSC 63 (1985), the Company in its initial filing clearly recognized and understood that facility proposals are typically considered as part of an overall long-range forecast review.

Third, the Siting Council consistently reviews the adequacy of transmission-related issues even in proceedings where the company has proposed no jurisdictional facilities. In Masschusetts Electric Company, et al., 15 DOMSC __ (1986) [EFSC Docket 83-24], the Siting Council considered an electric company's compliance with conditions attached to a previous approval of a facility within the context of reviewing a long-range forecast.

Accordingly, the Siting Council finds that consideration of the Company's transmission plans and planning is critical to a meaningful review of the Company's supply plan and, as such, falls squarely within the Siting Council's jurisdiction.

b. Adequacy of the Downtown Transmission System

To analyze the adequacy of its downtown Boston transmission system, the Company used load-flow studies to analyze the adequacy of its transmission system under certain assumed load, generation and transmission conditions (Tr. III, p. 15). The Company analyzed the performance of the downtown system in the event of double contingencies and also under worst case scenarios (Tr. III, p. 66). Based on the results of such analyses, the Company identified the need to shed load at substations serving parts of the City of Boston in the event of New Boston units 1 and 2 were to go out of service during load conditions at 79 percent of peak in summer 1987, and at 75 percent of peak in summer 1988. The Company asserted that the likelihood of load shedding in parts of the City of Boston was unacceptably high until BECO could resolve the problem through the installation of a new 345 kV transmission system in downtown Boston.

Consistent with findings made in previous decisions, the Siting Council finds that: (a) the Company's use of load flow studies is an acceptable method for analyzing the performance of a transmission system under different assumed conditions; (b) Boston Edison's use of double-contingency assumptions is an appropriate method for analyzing the reliability of its downtown transmission system; and (c) the Company's need to shed load in the event of reasonable contigencies is a problem that an electric company should plan to avoid. In re Cambridge Electric Light Company, 15 DOMSC __, 17, 20, 23 (1986); In re Massachusetts Electric Company, et al., 13 DOMSC 119, 194, 198 (1985); and In re Boston Edison Company, 13 DOMSC 63, 70-73 (1985).

Based on the record in this proceeding, the Siting Council finds that Boston Edison has known since 1983 that by the late 1980s the Company faced an unacceptably high risk of having to disconnect customers in the event of the double contingency that both units of New Boston go out of service during peak load periods (Tr. III, p. 102; Exh. BOS-14).

The Siting Council finds further that in 1983 and 1984 the Company proposed certain plans to upgrade and reinforce its existing downtown transmission system. These plans included (a) adding a forced cooling system and a heat-sensing cable monitoring system on portions of the existing 115 kV transmission system, and (b) construction of a new 345 kV downtown transmission system, the first phase of which was planned for 1988 (Exhs. BOS-17, HO-2, sec. II). The improvements to the 115 kV system have been installed and are operating. The first portion of the planned 345 kV downtown transmission system is not yet under construction and is now expected by the Company to be in service by June 1989.

The Siting Council finds that the Company's completed reinforcements to the its 115 kV downtown transmission system have contributed to the improvement of the reliability of that system. But in light of the fact that the Company itself views these efforts as "interim actions in order to minimize potential adverse reliability impacts on customers in the downtown area" (City Brief, pp. 33-34, emphasis added), the Siting Council finds that until the Company can put the planned 345 kV Mystic-Downtown transmission line in service, the Company's upgraded 115 kV transmission system is inadequate to avoid the risk of disconnecting customers in parts of Boston in the event that both units of New Boston go down during summer peakload conditions.

With respect to the level of risk that exists regarding load shedding in parts of the City of Boston during the summers of 1987 and 1988, the City asserts that based on the Company's evidence,[36] the risk of a blackout is 33 percent in the summer of 1987 and 50 percent in the summer of 1988 (City Brief, pp. 4, 12-15). The Company asserts it did not calculate the probability that load would have to be shed in 1987 and in 1988 (Tr. III, pp. 101-102). However, based on testimony and exhibits presented by BECO, the Siting Council finds that the risk of a blackout in parts of the City of Boston as 56 percent in the summer of 1987, and 75 percent in the summer of 1988.[37] In light of this evidence, the Siting Council finds that the risk of a blackout in the City of Boston is intolerably high during the summers of 1987 and 1988 -- and in all subsequent summers if the Company has not put the new Mystic-Downtown line into service.

For that reason alone, the Siting Council finds that Boston

36/The Company's evidence is not provided in the form of joint probabilities (Tr. III, p. 98). The Company's explanation of load-shedding risk is expressed quantitatively as follows: "Assuming all downtown transmission lines in service[,] load curtailment could be required for Boston Edison load levels in excess of approximately 2080 MW, 79% of peak in 1987. This load level would typically be reached or exceeded 40 days during the 1987 summer. For the 1988 summer the load disconnection threshold level will decrease to approximately 2000 MW, 75% of peak. This load level should be achieved approximately 60 days. Load shedding would be triggered only if both New Boston units were out-of-service on these heavy load days. Based on experience the simultaneous unavailability of both New Boston units could be expected to occur one to two days each summer" (Exh. BOS-11; see also Tr. III, pp. 93-98). The Company states that the load-related and generation-related contingencies are independent in terms of their probability of occurence (Tr. III, p. 97).

37/The Siting Council's risk calculation is attached in Table 7. This calculation assumes the data presented in the footnote above, which relates to a double contingency case (i.e., all existing transmission lines operating and two generating units going out), rather than a "worst case" contingency (which assumes the additional loss of a Mystic-K Street 115 kV line) (Exh. BOS-11, Tr. III, pp. 118-120).

Edison is not ensuring an adequate supply of reliable power to its customers in the City of Boston.

c. The Company's Transmission System Planning Process

The Siting Council also addresses the question of whether the Company has proceeded with its transmission planning in a manner that has attempted to provide for an adequate supply of reliable power for all of its customers, and in particular for customers in the City of Boston.

Starting in 1983, the Company recognized that it would not be able to install new, planned 345 kV transmission facilities in downtown Boston by the time they would be needed to avoid load shedding under certain reasonably likely contingencies. The Company undertook facility-related actions starting in 1983 and 1984, so as to lower the risk of a blackout in the City of Boston -- a risk that would exist until the new 345 kV transmission facilities were in place. The Company has proceeded with the licensing of its proposed first 345 kV Mystic-Downtown line, and the Company expects to put it in service by summer 1989.

While the Siting Council rejects the City's allegation that the Company has been idle on the Downtown Problem (City Brief, pp. 7-8), the Siting Council notes that the Company has failed to address its transmission problems with due diligence. For example, while the Company filed an Environmental Notification Form with the state in March 1985 and received from the Executive Office of Environmental Affairs an approval of the Company's Final Environmental Impact Report on February 26, 1986, the Company did not petition the MDPU for a Certificate of Convenience and Necessity until November 1986 (BECO Brief, p. 27). This sort of delay does not support a finding that Boston Edison has initiated a licensing schedule for the Mystic-Downtown line that adequately responds to the urgent need for the line.

Further, the Siting Council finds that the Company did not explore all possible options for minimizing the risk of a blackout in downtown Boston in the short run. In 1983, when the Company began to realize that it would not be able to place its proposed Mystic-Downtown line into operation soon enough to avoid the risk of load shedding during summer peakload conditions and under certain generation contingencies, the Company evaluated only "do nothing" and transmission-facility solutions to the problem. Ultimately, the Company identified and implemented certain "interim measures" to upgrade its existing transmission system until BECO could put its preferred transmission-system reinforcement plan into place in 1989.

However, the Company provided no testimony or exhibits to show that since 1983 the Company ever considered any solutions that would have enabled the Company to influence the type or pace of load growth in downtown Boston that was hastening the need for the new 345 kV transmission line. The record reveals no efforts on the part of Boston Edison between 1983 and 1986 to reduce the pace of growth through encouraging more energy-efficient building construction practices or the installation of efficient electrical equipment or appliances in new commercial buildings in downtown Boston.

Further, the Company stated that it does not change the schedule or design of its conservation and load management strategies as a response to faster-than-expected load growth (See Section III.G, infra). If the Company had started in 1983 to implement an aggressive load-management strategy targetted at downtown Boston customers and aimed at enabling the Company to better manage downtown Boston loads during summer peakload conditions, the magnitude of the Company's potential load-shedding problem during the upcoming two summers might have been reduced.

The Company decided only late last year to implement a few load-management programs in 1986 and 1987 under which the Company would pay customers to shed or shift their loads off of the Company's peak.[38] But the Company has not targetted these programs at

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38/ In August, 1986, and December, 1986, the Company's management authorized several conservation and load management programs for implementation starting in late 1986 and 1987 (Exh. HO-159). Two of these programs -- the "Generator Assistance on Peak" program and the "G-3 Load Curtailment" (footnote continued) downtown Boston customers (Exh. HO-159; Tr. I, pp. 24-25). In addition to waiting too long to decide to implement these programs, the Company's current implementation schedule for them is too slow for the Company to use these load-management options to help minimize the Downtown Boston reliability problem during 1987 and 1988 (Id.).

Still, the Siting Council sees no reason why the Company could not start today to implement even these programs much more aggressively as a way to help the Company reduce the risk of a blackout in parts of the City of Boston during the next two summers.

Absent evidence that the Company ever considered any such load-management options as even partial solutions to the Downtown Problem in the short run, the Siting Council finds that the Company has not adequately planned for providing reliable service to the City of Boston.[39] Further, the Siting Council finds that Boston Edison's

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(footnote continued) program -- are designed to enable the Company to pay customers so that BECO can call upon them to shed load during the Company's peak period (Id.). During the 1987 summer season, Boston Edison plans to have only five customers involved on the Generator Assistance on Peak program, and ten customers on the G-3 Load Curtailment program (Id.). The other seven programs include: a thermal storage load-shifting program for commercial/industrial customers; a flourescent light rebate program for commercial/industrial customers; a similar program for residential customers; a central air conditioner load-management program for residential customers; a similar one for commercial/industrial (G-2) customers; a program to offer rebates to residential customers to purchase energy-efficient refrigerators (Id.)

39/As further evidence of the Company's planning inadequacies relating to the Downtown Problem, the record shows that if the Company had pursued its plan to convert New Boston 1 and 2 to coal -- a plan BECO abandoned some time in late 1985 or early 1986 -- the Company would have taken each of these units out of service for an extended period of time at different points during the summers of 1987 or 1988 (Tr. II, pp. 186-191). If BECO had actually gone through with the coal conversion at New Boston, the Company would have placed customers in the City of Boston at a heightened risk of a blackout during each conversion-related outages, since (a) the Mystic-Downtown line would not yet be in operation, (b) there would be a 100-percent likelihood that one of the New Boston units would be out, and (c) load in parts of the City of Boston would have to be shed if the other one went out (i.e., a single contingency, rather than a double contingency). BECO actively pursued this plan for at least a year beyond the time the Company realized it could not put its proposed Mystic-Downtown transmission line in service before 1988 or 1989.

inadequate planning has exposed firm customers in parts of the City of Boston to an unacceptably high risk of a blackout in the summers of 1987 and 1988.

The record demonstrates that the Company has not integrated its transmission system planning with its resource planning process in general and in particular with respect to its demand-management planning (see section III.G for a further discussion of this issue).

Based on the foregoing, the Siting Council finds that Boston Edison has failed to adequately plan to ensure a reliable power supply for its customers.

G. Least-Cost Supply

The Company states that its planning process is designed to ensure that Boston Edison has an optimal supply and demand plan (Exh. HO-10, p. 2). BECO asserts that it achieves a least-cost resource plan through application of a uniform standard for comparing alternatives: "the standard against which supply and demand plans are measured is marginal capacity costs and marginal fuel costs. Mixes of various supply and demand options (including rate design and strategic marketing) are examined with the object of selecting a combination which results in the lowest future cost-of-service for our customers" (Id.).

The Company states that this process "ensures that the Company will build generation facilities only when they are the most economic resource when compared to other options (supply and demand) on a standard basis" (Id., p. 19).

With respect to conventional power supplies, the Company says it uses its EGEAS and internal production-costing techniques to identify and develop an expansion plan that minimizes cost (Exh. HO-9, p. 5; Exh. HO-10, pp. 17-19). (See also Section III.C, supra.)

In terms of how the Company treats power purchases from small power producers and cogenerators within its least-cost resource planning, BECO has provided evidence about its new contracting procedures for purchasing electricity from such facilities within the context of a least-cost resource planning process (Exhs. HO-12, HO-13). (See Section III.C, supra.)

Regarding inclusion of demand management in the Company's least-cost plan, Boston Edison states that it utilizes a process that leads the Company to implement conservation and load-management "measures which affect the use of electricity in such a way as to keep the cost of power lower, for all customers, than it would have been if the action was not taken" (Exh. HO-10, p. 21). (See Section III.C, supra.) The Company argues that "it has made significant progress over the past few years, particularly since the end of 1984, in the development of a sound basis and approach to demand management planning. The principal accomplishments include not only the three programs that are now running on a full-scale basis, but also the process whereby those programs are conceived, evaluated and moved towards full scale implementation" (BECO Brief, p. 19). The Company asserts that this process yields "a workable solution for placing demand-side options on an equal footing with supply-side options" (Exh. HO-7, p. 13).

The City argues that the Company has not addressed the issue of least-cost planning as required by the Siting Council (City Brief, p. 25). However, the City provided neither its own evidence nor a detailed analysis of the Company's evidence as support for the City's position.

The Company's commitment to demand-management programs as part of a least-cost planning strategy has been criticized in another forum. On June 26, 1986, the MDPU issued an order which concluded that the Company had failed to meet its public service obligation. Boston Edison Company, DPU 85-266-A/85-271-A (1986).[39a] In that case, the MDPU concluded that "the Company has not engaged in a least-cost planning strategy because it has adopted planning criteria which prevent the implementation of cost-effective energy conservation and load-management...programs. Such programs could have been designed to delay, in a cost-effective manner, the date additional capacity will be needed. We find in this Order that this failure has resulted in a cost of service higher than would exist had the Company made a true commitment to reasonable C&LM measures" (Id., p. 10; See also pp. 6-15).

39a/In this proceeding, the Siting Council has taken administrative notice of the following dockets of the Massachusetts Department of Public Utilities: DPU 85-266-A/85-271-A, DPU 1720, and DPU 85-58 (Tr. I, p. 4); DPU 1350 (Tr. II, p. 137); DPU 86-78 (Tr. III, p. 49); and DPU 86-255 (Tr. III, p. 68).

1. Comparison of Alternatives on an Equal Footing

Boston Edison provided extensive evidence in the form of testimony and documentation as to how the Company evaluates resource alternatives when it attempts to develop a least-cost, reliable supply plan (Exhs. HO-3, HO-5, HO-6, HO-7, HO-8, HO-9, HO-10; Tr. I, pp. 22, 53, 69-79; Tr. II, pp. 26-30). To facilitate the development of such a plan, the Company said it reorganized its supply and demand planning functions into a single department that includes: demand forecasting; planning for and evaluation of conservation and load management; planning and contracting for SPP and cogeneration; and more traditional generation expansion planning (Exh. HO-10; Tr. I, pp. 68-69, 73-78; Tr. II, pp. 98-100; BECO Brief, p. 14). Mr. Hahn testified that in the past three years, BECO's demand-management planning has been bolstered with resources and that Boston Edison now has a "truly integrated supply and demand planning process...that takes a back seat to no one" (Tr. I, p. 69).

The Siting Council recognizes that Boston Edison has effected a number of changes since the last time the Siting Council issued an order on a BECO filing. In particular, the Siting Council acknowledges the harsh criticism the Company received regarding its planning process as a result of the June 1986 MDPU order. Accordingly, throughout this entire proceeding, the Siting Council repeatedly and explicitly requested the Company to provide information that could reflect not only the evolutionary nature of the Company's planning process, but also the ways in which the Company has responded to that order.

The record in this proceeding is replete with evidence which shows that the Company utilizes different analyses and decision-making standards for demand-management resources than it employs for supply-side resources. This differential treatment undermines the Company's ability to develop a least-cost plan in a number of ways:

(1) Mr. Hahn stated that he has never examined and therefore is unaware of whether it would be cheaper (e.g., in terms of system revenue requirements) for the Company to meet the marginal kilowatt or kilowatthour of demand through a supply-side approach or through a

demand-side approach (Tr. II, pp. 45-53). For example, the Company never considered implementing demand-management programs on a more aggressive schedule as a source of (a) replacement power for the energy lost due to the lengthy, on-going outage of Pilgrim 1[40] (Tr. I, p. 141; Tr. II, pp. 164, 173, 192), or (b) to avoid capacity deficiencies in the short run if the Company's planned additions are not available as expected (Tr. II, p. 166). Similarly, even when it changes its load-growth or fuel-price assumptions in its contingency plans, the Company never varies its expectations with regard to what demand-management programs would then be cost-effective and whether it should modify its demand-management implementation schedule or the economic incentives embodied in any individual program (Exh. HO-9; Tr. II, pp. 30, 33-37, 39-40, 42-45).[41]

In the event of these contingencies, the Company relies upon only conventional power purchases or investments in traditional powerplant projects as viable responses. In fact, the Company even calls its long-range supply plan and its action plan an "expansion plan" (BECO Brief, p. 20). Further, Mr. Hahn stated that BECO had not compared the costs of the nine demand-management programs now authorized for implementation against the ceiling price established for buying power from SPP and cogenerators in the auction process (Tr. I, pp. 45-46). The Company concedes that it may have missed some opportunities for obtaining cost-effective power supplies when it did not evaluate whether demand management would be cheaper to implement than the kinds of supply-side options it has pursued in the short run

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40/BECO asserts that "Until Pilgrim returns to service, the Company will continue to seek the least cost replacement energy available" (BECO Brief, p. 24; see also Tr. I, p. 141). However, under cross-examination, Mr. Hahn stated that the Company never considered changing its demand management schedule as a source of replacement energy for Pilgrim (Tr. II, pp. 191-192).

41/Once the Company selects as a candidate for implementation a program from the original list of 40 options, the Company evaluates the sensitivity of that program's benefit/cost ratio to varying assumptions regarding participation rates, discount rates, and so forth (Tr. II, pp. 41-44).

(Tr. I, pp. 56-57).

As such, the Siting Council concludes that the Company's supply planning process can only view these supply-side and demand-side options in a non-integrated way.

(2) The Company's witness, Mr. Ruscitto, explained that in BECO's evaluations of 40 demand-management options, a benefit/cost ratio greater than one for any particular program indicates that the Company could implement that program and provide a lower cost of supply relative to a resource mix that did not include that program (Tr. I, pp. 17-18). When the Company performed its analyses of the 40 demand-side programs, 36 of them had a benefit/cost ratio greater than or equal to one. However, in spite of the Company's own expectation that it will need to add capacity both in the short run and the long run (see Section III.E, supra), and even though the Company has recognized since 1983 that a downtown Boston reliability problem would arise before the Company could build a transmission facility to correct it (See Section III.F, supra), the Company has chosen to implement only a small set of the 36 demand-management programs for which its own analyses show favorable benefit/cost ratios and whose implementation would provide the opportunity to lower customers' costs relative to a supply mix that excludes those programs (Tr. I, pp. 53-54; Tr. II, p. 200).

This is particularly troubling in light of statements by Mr. Hahn and Mr. Ruscitto that the Company has significantly modified its approach to demand management in response to being placed on notice by the MDPU in its June 1986 Order that there was an immediate need for the Company to pursue demand management as part of a least-cost supply plan (Tr. I, pp. 21-22, 70-72). In August 1986 -- two months after the MDPU issued its decision -- the Company authorized and commenced implementation of only three programs, and in December 1986, the Company approved only six more for implementation (Exh. HO-159). According to Mr. Hahn, such authorizations represent the "corporate commitment" to a particular demand-managment program (Tr. II, p. 104). Mr. Hahn and Mr. Ruscitto stated that the MDPU's order had a major impact on the Company and that Boston Edison is responding as quickly as possible at this point (Tr. I, p. 31-32, 52-53; Tr. II, p. 25).

However, the Siting Council concludes that if the Company were actually making substantial changes in order to pursue a reliable and least-cost supply mix, it would be aggressively implementing all cost-effective demand management throughout the Company's service territory and targetting the marketing of such efforts in areas such as parts of the City of Boston where the Company has identified as potential locations for reliability problems in the short run.

The record shows that Boston Edison is doing neither of those things. Accordingly, the Siting Council finds the Company is not aggressively pursuing all cost-effective demand management in spite of the Company's expectation that it needs to add energy supplies and capacity.

(3) The Company has developed a detailed and comprehensive computerized methodology for comparing the costs and benefits of demand-management programs (Exh. HO-8; Tr. II, pp. 126-130, 155-157). This approach provides the Company with a relatively sophisticated and sound methodological foundation for performing the kinds of analyses the Company needs to develop least-cost plans. However, the Company does not apply this metholodogy in a way that enables the Company to carry out least-cost planning over time (Tr. II, p. 35). The record shows that the Company has used its methodology to evaluate the Company's 40 conservation and load-management options only once in the past three years, and to evaluate the Company's proposed pilot programs only one other time since then (Tr. I, pp. 35-44; Tr. II, pp. 33-37; Exh. HO-153).

This is the case in spite of the fact that the Company recognizes that many of the factors that signficantly affect the Company's forecasted need for new capacity and its long-run marginal energy and capacity costs have changed significantly during that time and could change again within the short run (Tr. I, pp. 39-42, 119-121; Tr. II, pp. 27-28, 40-41). Mr. Hahn stated that BECO plans to rerun the analyses on the full set of options only as early as summer 1987 (Tr. I, pp. 42-43). At the same time, the Company reestimates its contingency analyses of more traditional power purchase options on a more regular basis (Tr. I, pp. 102-103; Exh. HO-69).

The Siting Council finds that the Company has failed to use this methodology iteratively and often to analyze whether demand-management programs remain cost-effective even under different assumptions (e.g., what level of a lighting rebate would still be cost-effective if the Company's marginal cost went up). Therefore, the Siting Council finds that the Company has failed to adequately monitor changes in the cost effectiveness of its demand-management options in accordance with changes in the Company's avoided cost estimates.

(4) Boston Edison has no common basis for directly comparing the economic benefits and costs associated with demand-side options against those of supply-side options. To compare demand-management programs against each other, the Company calculates their net present value and benefit/cost ratios, using the Company's long-run marginal cost as the basis for valuing benefits (Tr. I, p. 49). To compare SPP and cogeneration options against alternative supply-side options, the Company establishes a long-run cost of avoided energy and capacity in terms of a levelized cents-per-kilowatthour cost ("¢/kwh") and then allows SPP and cogenerators to submit bids to sell electricity to the Company at or below that cost. Mr. Hahn testified that: (a) Boston Edison does not have a ¢/kwh cost value for any of the 40 demand-management options it had analyzed; and (b) it would take weeks to calculate such values using up-to-date assumptions (Tr. I, pp. 46-50; Tr. II, pp. 50-51). Mr. Hahn admits that he has not made such direct cost comparisons of demand-management options and supply-side options (Tr. II, pp. 45-53).

Therefore, the Siting Council concludes that the Company's analytic measures do not accommodate economic comparisons of demand-side options directly against supply-side options.

(5) In response to questioning from the Siting Council, Mr. Hahn expressed his concerns about articulating the risks associated with particular contracts the Company holds with independent power producers for as-yet unconstructed projects, since he did not want to give the impression that the Company was undermining the ability of those projects to come on line (Tr. I, pp. 104-105). Yet, Mr. Hahn and Mr. Ruscitto repeatedly articulated the Company's concerns about

the "questionable" feasibility of demand-side management programs due to customers' disinterest or unwillingness to participate in the Company's demand-management programs (Tr. I, pp. 30, 53, 101, 104-105, 118-119; Tr. II, pp. 31-33, 43, 57).

The Siting Council finds that the Company adopts a different attitude regarding articulating the risks of demand-management options than it has about discussing the risks of specific supply projects.

(6) In the Company's supply planning process which includes a base case, contingency analyses and expansion plans, the Company analyzes the economics of supply-side additions using 100-MW capacity increments (Exh. HO-9, p. 7). Boston Edison argues that the reason the Company cannot include demand-management options within its contigency planning framework is that demand-management options come in much smaller increments and offer limited "supplies" in absolute terms (i.e., less than 100 MW at a time) (Exhs. HO-25, HO-28).

Based on this assertion alone, the Siting Council finds that the Company has failed to establish that its expansion planning methodology is unbiased with respect to its treatment of demand-side versus supply-side options that the Company can call upon in response to contingencies.

(7) The 1986 Boston Edison Forecast included adjustments for conservation, load management and time-of-use rates associated with the long-run effects of implementing all cost-effective programs starting with the six pilots proposed in 1985 (Exh. HO-3; Exh. HO-7). (See Table 8.) Since that filing was presented to the Siting Council, the Company realigned its schedule for implementing demand-management programs, but according to Mr. Ruscitto, those changes would not alter the conservation/load management adjustments the Company made to the 1986 Forecast (Tr. I, pp. 32-35). The Company did not provide documentation in support of this assertion.

Accordingly, the Siting Council finds that the Company's estimates of demand-management resources the Company can rely upon in the short run do not have a credible technical basis.[42]

42/This finding could seem inconsistent with the Siting Council's unconditional approval of the Company's (footnote continued)

(8) Mr. Hahn and Mr. Ruscitto concede that demand-management programs could reduce forecasting error, for example, by reducing the weather-sensitivity of the energy usage of certain equipment. The Company also concedes that certain types of demand management can facilitate supply planning by reducing risk associated with demand uncertainty (Tr. I, pp. 54-56; Tr. II, pp. 55-58). However, the Company does not take this benefit into consideration when it evaluates the benefits and costs of various possible implementation schedules and strategies. The Company's witness agreed that BECO may have missed all kinds of opportunities to have captured benefits from demand management (Tr. I, pp. 56-58).

This analytic treatment of demand management by the Company means that the Company's analyses underestimate the benefits to the system of relying upon demand-side options as integral parts of the Company's supply plan. Based on the Company's testimony, the Siting Council finds that the Company has failed to consider the risks and benefits of demand management fairly in its overall supply planning process.

To the Siting Council, the Company's supply and demand planning effort reads well on paper; but, for the reasons stated above, Boston Edison is not performing analyses and actually making decisions in line with tht plan so as to enable it to develop a least-cost supply plan and minimize its customers costs of service.

(footnote continued) 1985 and 1986 demand forecasts (See Section II.C, supra), which include the Company's adjustments for the impacts of Company-sponsored conservation, load management, and time-of-use rates, as required by the Siting Council in its previous order (See Section II.C.1.b). That unconditional approval recognized that the Company had complied with the Siting Council's explicit order to integrate demand management into BECO's forecast.

The criticism noted above relates to the Company's treatment of demand-management impacts in an inflexible way. In the future, the Siting Council expects the Company to treat demand-management plans in a way that reflects the Company's expectations about the timing and availablility of specific amounts of "supplies" that can result from implementing specific demand-management programs or strategies.

On the one hand, it is clear that the Company can perform least-cost generation-expansion planning. Further, the Company has embarked on a program to contract for power from SPPs and cogenerators within a least-cost generation-expansion planning process. But on the other hand, in spite of numerous Company statements to the contrary, the evidence overwhelmingly demonstrates that in important analytical and decisionmaking ways, the Company is still not treating demand-management resource options on an equal footing with supply-side options.

This conclusion is troublesome enough in light of the Siting Council's own statute and decisions that require companies to adequately consider conservation and load-management. G.L. c. 164, sec. 69J. In Re Cambridge Electric Light Company, et al., 15 DOMSC __ 7, 27, 40 (1986); Massachusetts Electric Company, et al., 13 DOMSC 119, 177-179 (1985). But it is all the more problematic in light of the order of the Siting Council's sister agency, the MDPU, now over nine months ago, that the Company fully integrate conservation and load management into its demand and supply planning process. MDPU 85-266-A/85-271-A, pp. 6-15, 143-151.

2. Conclusions

Accordingly, the findings above show that Boston Edison treats demand-side options differently from supply-side options in the following ways:

(1) Boston Edison's demand and supply planning process is not fully integrated;

(2) Boston Edison is not pursuing all cost-effective demand management in spite of the Company's need for energy and additional capacity;

(3) Boston Edison does not adequately monitor how the cost effectiveness of demand-management options changes over time in accordance with changes in the Company's avoided cost estimates;

(4) Boston Edison's analytic measures do not accommodate direct economic comparisons of demand-side options against supply-side options;

(5) Boston Edison has a different attitude about articulating the risks of demand management programs as opposed to discussing the risks of particular supply projects;

(6) Boston Edison's expansion planning methodology is not unbiased with respect to treating demand management and supply-side options as alternatives the Company could rely upon in response to contingencies;

(7) Boston Edison's estimates of demand-side resources available to the Company in the short run do not have a credible technical basis; and

(8) Boston Edison's analyses underestimate demand management's benefits to the system.

These findings demonstrate that Boston Edison's resource-planning process does not ensure a least-cost energy supply for the Company's customers, since BECO does not treat demand-management options on an equal footing with supply-side options in relevant analyses and decisions.

Therefore, the Siting Council finds that the Company's supply plan does not ensure a least-cost energy supply, as required in the Siting Council's enabling statute.

H. Diversity of Supply

As part of Condition 3 of its last decision, the Siting Council required Boston Edison to provide information on its fuel diversification initiatives. In this proceeding, the Company stated that it had attempted to convert generators at New Boston and Mystic to coal but had since dropped those efforts (See Section III.B, supra).

The Company also discussed another diversification effort, the conversion of three major fossil fuel units at New Boston and Mystic to dual-fuel (oil and natural gas) capability (Exh. HO-64). The Company provided a fuel-use forecast for 1986 which, when compared to a fuel-use forecast for 1983, indicates the Company's lower dependence on oil due to the dual-fuel capability. Based on those forecasts, oil generation was expected to decrease to 37 percent[43] from the 71 percent forecast for 1983; nuclear fuel generation was expected to remain constant at about 29 percent; natural gas generation was forecast to rise from virtually no generation in 1983 to about 34 percent in 1986 (Exh. HO-4, p. I-4; see also BECO's 1983 Forecast, Vol. 2, March 1, 1983, p. I-4).

The Siting Council finds that this more even balance in oil and gas generation improves the Company's fuel diversification position.

The Company also reported other diversification initiatives. Boston Edison is purchasing nuclear power from New Brunswick and plans to purchase hydro-power from Hydro Quebec under NEPOOL's Phase II purchase agreement (Exh. HO-64). In addition, the Company's RFP for attracting generation from SPPs and cogenerators provides an incentive for non-oil/gas facilities (Exh. HO-64).

Based on the foregoing, the Siting Council finds that the Company has complied with Condition 3 as imposed in the last decision.

43/All percentages are based on fuel consumption from BECO's own generation on a British thermal unit ("Btu") basis.

I. Summary of the Supply Plan Analysis

The Siting Council has found that the Company's supply plan fails to: (1) ensure adequate resources to meet customer requirements (Section III.E, supra); (2) ensure a reliable power supply for all of its customers (Section III.F, supra); and (3) ensure a least-cost supply of energy over the forecast period (Section III.G, supra).

Accordingly, the Siting Council rejects the Company's 1985 and 1986 supply plans.[44]

In rejecting the Company's supply plan, the Siting Council is forced to note the disquieting similarities in the Company's foot-dragging approach to: addressing the integration of cost-effective demand-management options into its supply mix; addressing all possible steps to reduce the risk of a downtown Boston transmission problem in 1987 and 1988; and addressing the possibility that the Company could lose a capacity credit for the Pilgrim nuclear power plant in the short run. In each of these cases, Boston Edison refrained from addressing the problem until such time as the Company was convinced beyond any doubt that a problem existed.

44/The Siting Council notes that the Company has established that it is proceding with the siting of both its Mystic-Downtown and Mystic-Golden Hills transmission lines, which have been previously approved by the Siting Council. In re Boston Edison Company, 13 DOMSC 63 (1985); In re Boston Edison Company, 2 DOMSC 58 (1977). In the instant proceeding, no evidence has been presented which would indicate that these facilities are no longer necessary. In fact, the record shows that the Mystic-Downtown line is needed sooner than the Company's anticipated in-service date. The Siting Council encourages the Company to complete these projects in an expedient manner.

The Siting Council's rejection of the Company's 1985 and 1986 supply plans should not be interpreted as a recision of the Siting Council's previous decisions regarding these lines.

Therefore, the Siting Council expressly finds that commencement of construction of the Mystic-Downtown line and the Mystic-Golden Hills lines is consistent with the Company's most recently approved long-range forecast. However, the Company could not commence construction of any future facility proposals until the Company files a forecast and supply plan that is approved by the Siting Council.

Unfortunately, the record in this case is replete with evidence of the consequences of that approach. The Company's inadequate planning process has placed Boston Edison's customers at an unacceptable level of risk of having inadequate resources in the short run. At the same time, customers may face higher-than-necessary energy costs because the Company has not been conducting its planning in a least-cost fashion. The Siting Council finds this "head in the sand" approach to be woefully shortsighted and a wholesale betrayal of the Company's public service obligation.

IV. DECISION AND ORDER

The Energy Facilities Siting Council hereby unconditionally approves the demand forecast and rejects the supply plan as presented in the Third and Fourth Supplements to the Second Long-Range Forecast of Electric Power Needs and Requirements of Boston Edison Company including the requirements of the Concord Municipal Light Plant and the Electric Division of the Wellesley Board of Public Works.

The Siting Council hereby orders Boston Edison:

(1) to develop immediately a clear and specific plan for squarely facing the possibility of losing Pilgrim capacity credit. Such plan shall include a time schedule providing for specific actions by the Company if Pilgrim generation resumption meets any further delays. The Company is ordered to file such plan with the Siting Council by May 1, 1987 and to report all Company actions that either follow or modify that plan.

(2) to develop immediately a clear and specific plan for minimizing the risk and extent of disconnecting firm customer load in the City of Boston for all summers prior to the expected in-service date of the Company's proposed 345 kV Mystic-Downtown transmission line. This plan shall identify all options available to the Company to reduce the risk and extent of load shedding in the City of Boston

including consideration of an immediate and aggressive demand management strategy. Further, the plan shall provide for actions the Company will take, including a schedule for implementing those actions, to minimize the risk and extent of load shedding in each summer covered by the plan. The Company is ordered to file such plan with the Siting Council and the City of Boston by June 1, 1987 and to report all actions that either follow or modify that plan.

Boston Edison is hereby ordered to file its next long-range forecast on February 1, 1988.

Robert Shapiro

Robert Shapiro
Hearing Officer

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

Sharon M. Pollard

Sharon M. Pollard
Chairperson

April 3, 1987
Date

TABLE 1

Boston Edison Company
Demand Forecast Summary

ANNUAL REQUIREMENTS:

	Annual Energy[1] Requirements (GWh) 1986	1995	Average Annual Compound Growth Rate 1986-1995
Residential w/Heating	716	975	3.5%
Residential w/o Heating	2,285	2,483	0.9%
Commercial	6,087	7,841	2.9%
Industrial	1,897	2,424	2.8%
Street Lighting	135	135	0.0
Wellesley, Concord	311	367	1.9%
Load Management	0	(10)	---
Losses and Internal Use	1,075	1,336	2.4%
Total Energy Req's	12,508	15,551	2.5%

PEAK REQUIREMENTS[2] (SUMMER):

	Peak Load[1] (MW) 1986	1995	Average Annual Compound Growth Rate 1986-1995
Residential	415	468	1.3%
Commercial	1,581	1,894	2.0%
Industrial	458	542	1.9%
Wellesley, Concord	62	74	2.0%
Total Peak Load	2,519	2,980	1.9%

Notes: 1. Totals may not add due to rounding.
2. Losses and internal use are added to the peak load forecast within each customer group (about 9.4 percent historically). Street lighting does not make a significant contribution to peak load.

Sources: Exh. HO-3, pp. K-9, K-11, I-33; Exh. HO-127.

TABLE 2

Boston Edison Company
Base Generation Expansion Plan[1]

Base Load Forecast, Base Fuel Forecast
(MW)

Year[2]	Coal	Combined Cycle	Combustion Turbine	Ocean State Power	Cumulative
1986					
1987					
1988			100		100
1989					
1990				100	200
1991					
1992		100	100		400
1993					
1994					
1995					
1996		100			500
1997					
1998		100			600
1999					
2000		100			700
2001		100			800
2002					
2003		100			900
2004					
2005		100			1000
2006		100			1100
2007			100		1200
2008					
2009			100		1300
2010					
Totals	0	800	400	100	

Notes: 1. The Company analyzes capacity addition in 100 MW increments to avoid biases due to unit size.
2. The Siting Council presents the Company's expected generation plan through 2010 for information only. We restrict our review to our ten-year planning horizon which ends in 1995.

Source: Exh. HO-9, Table 6.

TABLE 3

Boston Edison Company
Recommended Generation Expansion Plan

Base Load Forecast, Base Fuel Forecast
(MW)

Year	Short-Term Purchase [1]	Dispatchable Purchase [2]	Ocean State Power	Cogen and SPP	Cumulative
1986					
1987					
1988	100				100
1989					
1990			100		200
1991					
1992		100		200	400
1993					
1994					
1995					
1996				100	500
1997					
1998				100	600
1999					
2000				100	700
Totals	100	100	100	500	

Notes: 1. A short-term purchase is assumed to cover the 1988 to 1990 time period.
2. A 100 MW power purchase in 1992 may be from any party selling power, including cogenerators or SPP, but it must be dispatchable.

Source: Exh. HO-9, p. 4.

TABLE 4

Boston Edison Company
Generation Expansion Plan Sensitivity Analysis

Load Growth: / Fuel Prices:	Low / Low	Base / Low	High / Low	Low / Base	Base / Base	High / Base	Low / High	Base / High	High / High
<u>Year</u>	(1),(2),(3)								
1986									
1987			CT			CT			CT
1988		CT	CT		CT	CT		CT	CT
1989			CT			CT			CC
1990		OSP	OSP		OSP	OSP		OSP	OSP
1991	OSP			OSP			OSP		
1992	CT	CT,CT	CT,CT	CT	CC,CT	CC,CT	CC	CC,CC	CC,CC
1993			CT			CC			CC
1994			CC			CC			CC
1995									
1996		CT	CC		CC	CC		Coal	Coal
1997			CC			CC			Coal
1998		CC			CC			Coal	
1999			CC			CC	Coal	Coal	Co,Co
2000	CT	CC	CC	CC	CC	CC			
2001		CC	CC		CC	CC		Coal	Coal
2002			CC			CC		Coal	Coal
2003		CC	CC	CC	CC	CC	Coal		Coal
2004	CC		CC			CC		Coal	Coal
2005		CC	CC		CC	CC			Coal
2006		CT	CC	CT	CC	CC	CC	CC	Coal
2007	CT	CT	CT		CT	CC		CC	CC
2008			CT,CT			CT,CT		CT	CT,CT
2009		CT	CT		CT	CT			CT
2010			CT			CT			CT
Totals (MW)	500	1300	2300	500	1300	2300	500	1300	2300

Notes: 1. CT = Combustine Turbine; CC = Combined Cycle; Co = Coal; OSP = Ocean State Power.
2. Each time a unit is identified, it represents an addition of 100 MW.
3. The 200 MW purchase from Pt. Lepreau II is assumed to be indefinately deferred.

Source: Exh. HO-9, Tables 6 and 9 - 16.

TABLE 5

Boston Edison Company
Consolidated Demand Forecast and Generation Expansion
Summer Peak (MW)

Year	Summer Capability Respons	Current Summer Capacity & Purchases	Total Signed & Approved Purchases	Surplus (Deficit)	Total Likely Purchases	Surplus (Deficit)
1987	2947	2984	250	287	0	287
1988	3328	2984	250	(94)	0	(94)
1989	3350	2984	264	(102)	40	(62)
1990	3400	2984	426	10	168	178
1991	3501	2884	426	(191)	343	152
1992	3408	2784	176	(448)	343	(105)
1993	3417	2784	176	(457)	343	(114)
1994	3458	2783	176	(499)	343	(156)
1995	3466	2783	176	(507)	343	(164)

Capacity Losses:	Signed & Approved:	Likely Purchases:
Bear 1991	NU 1987	PRS 1989
PL I 1992	to 1991	BioEn 1989
MDC 1994	TDEn 1989	OSP 1990
	Peat 1989	AmR-F 1990
	EvrtE 1990	HQ 2 1991
	NEA 1990	

Notes: 1. Capability responsibilities are based on the Company's assumptions of 70% PIP phase in during 1987 and Seabrook I on-line in June 1987.
2. "Approved" purchases indicate MDPU contract approval; "likely" purchases have been signed by the parties but do not have MDPU approval.
3. Totals do not include expected capacity additions due to the Company's January 1987 Request for Proposals. Boston Edison has designed its RFP to attract 200 MW of cogeneration or SPP by 1991.
4. Everett Energy (EvrtE) was formerly known as Diamond East.
5. The Walpole combustion turbine is not included in the supply totals. The Walpole CT is rated at 76 MW and could be in service for the 1989 summer.

Sources: Exhs. HO-14 thru HO-84, HO-157.B, and HO-161.

TABLE 6

Boston Edison Company
Short-Run Contingency Analysis

1. <u>Simultaneous loss of Ocean State, Northeast Energy, and Everett Energy:</u>

Year	Base Case[1] Surplus (Deficit)	Loss of OSP, NEA, and EvrtE	Contingency Surplus (Deficit)	NU Purchase	Walpole Combustion Turbine	Possible Surplus (Deficit)
1987	287	0	287	150	0	437
1988	(94)	0	(94)	150	0	56
1989	(62)	0	(62)	150	76	164
1990	178	(252)	(74)	150	76	152

2. <u>High load growth rate:</u>

Year	High Load Growth Forecast	Summer[2] Capability Respons	Contingency Surplus (Deficit)	NU Purchase	Walpole Combustion Turbine	Possible Surplus (Deficit)
1987	2718	3094	(140)	150	0	10
1988	2832	3501	(267)	150	0	(117)
1989	2926	3544	(256)	150	76	(30)
1990	3001	3604	(26)	150	76	200

3. <u>Loss of Pilgrim Capacity Credit:</u>

Year	Base Case[1] Surplus (Deficit)	Loss of Pilgrim Capacity	Contingency Surplus (Deficit)	NU Purchase	Walpole Combustion Turbine	Possible Surplus (Deficit)
1987	287	0	287	150	0	437
1988	(94)	(495)	(589)	150	0	(439)
1989	(62)	(495)	(557)	150	76	(331)
1990	178	(495)	(317)	150	76	(91)

Notes: 1. See Table 5 for the short-run base case surplus/deficit.
2. Reserve requirements are based on the Company's assumptions of 70% PIP phase in during 1987 and Seabrook I on-line in June 1987 (Exh. HO-157B).

Sources: Exhs. HO-9, HO-157B, and HO-157C.

TABLE 7

Siting Council Calculation of
the Risk of a Blackout in Downtown Boston

Assumptions:
1. A summer period is 120 days.
2. If load exceeds certain threshold levels and both New Boston units are out of service ("OOS"), a blackout will occur.
3. The threshold level of 2080 MW will be exceeded on 40 of the 120 summer days in 1987.
4. The threshold level of 2000 MW will be exceeded on 60 of the 120 summer days in 1988.
5. Both New Boston units will be OOS on two days during the summer period in any given year.
6. All events are independent.

Method: The calculation of blackout risk due to both New Boston generating units being OOS is based on standard probability theory for sampling without replacement. For example, if the population consists of 120 summer days, it is assumed that on two of those 120 days both New Boston units will be OOS, and it is also assumed that load will exceed the threshold blackout level on one of the 120 days, then the probability that there will not be a blackout under those conditions is estimated by the following function:

$$\text{Pr[No blackout]} = \frac{\text{No. of days no blackout expected}}{\text{Total no. of days available}}$$

$$= (118/120) = 98.3\%$$

The probability of a blackout follows as,

$$\text{Pr[Blackout]} = 1 - \text{Pr[No blackout]} = 1.7\%$$

Calculation: If it is assumed that load will exceed the threshold level of 2080 MW on 40 of the 120 days (1987 summer), the probability of no blackout becomes,

$$\text{Pr[No blackout]} = (118/120)(117/119)(116/118)\ldots(79/81) = 44.3\%$$

and the probability of a blackout occurring is,

$$\text{Pr[Blackout in 1987 summer]} = 55.7\%$$

If it is assumed that load will exceed the threshold level of 2000 MW on 60 of the 120 days (1988 summer), the probabilities are,

$$\text{Pr[No blackout]} = (118/120)(117/119)(116/118)\ldots(59/61) = 24.8\%$$

$$\text{Pr[Blackout in 1988 summer]} = 75.2\%$$

Source: Exh. BOS-11

TABLE 8

Boston Edison Company
Projected Effects of Demand Management

	Annual Energy Requirements (GWh) 1986	1995	Reduction in Energy Consumption (GWh)	Average Annual Compound Growth Rate 1986-1995
Residential:				
Natural Forecast	3,001	3,521	---	1.8%
With Conservation	3,001	3,458	63	1.6%
Commercial:				
Natural Forecast	6,087	7,964	---	3.0%
With TOUR	6,087	8,012	(48)	3.1%
With Conservation	6,087	7,793	171	2.8%
With TOUR and C&LM	6,087	7,841	123	2.9%
Industrial:				
Natural Forecast	1,897	2,472	---	3.0%
With TOUR	1,897	2,492	(20)	3.1%
With Conservation	1,897	2,404	68	2.7%
With TOUR and C&LM	1,897	2,424	48	2.8%
Total Energy and Growth Rate Reduction			234	0.17%

	Peak Energy Requirements (MW) 1986	1995	Reduction in Peak Consumption (MW)	Average Annual Compound Growth Rate 1986-1995
SUMMER:				
Natural Forecast	2,519	3,227	---	2.8%
With TOUR	2,519	3,143	84	2.5%
With Conservation	2,519	3,069	158	2.2%
With Load Mngmt	2,519	3,138	89	2.5%
With TOUR and C&LM	2,519	2,980	247	1.9%
WINTER:				
Natural Forecast	2,246	2,980	---	3.2%
With TOUR	2,246	2,905	75	2.9%
With Conservation	2,246	2,854	126	2.7%
With Load Mngmt	2,246	2,934	46	3.0%
With TOUR and C&LM	2,246	2,808	172	2.5%

Source: Exh. HO-3, pp. E-23, F-27, G-11, and I-32; Exh. HO-128.

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 ammended by Chapter 485 of the Acts of 1971).

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

Petition of the Nantucket Electric Company for Approval of its Third Long-Range Forecast of Electric Needs and Resources	EFSC Docket No. 86-28

FINAL DECISION

William S. Febiger
Hearing Officer

April 2, 1987

The Energy Facilities Siting Council ("Siting Council") hereby APPROVES, subject to conditions, the demand portion and REJECTS the supply portion of The Third Long-Range Forecast of Electric Power Needs and Requirements of the Nantucket Electric Company ("the forecast").

I. INTRODUCTION

A. Overview

The Nantucket Electric Company ("Nantucket" or "the Company") is an investor-owned utility that provides electric service to the Island of Nantucket, exclusively. The Company is unique among Massachusetts electric utilities in that it is not in any way interconnected to the New England Power Pool ("NEPOOL"). Nantucket is one of the smallest electric companies in the Commonwealth, having annual sales totalling approximately one-tenth of one percent of electric sales in Massachusetts as a whole.

Seven diesel generators with a total capacity of 19.95 megawatts ("MW") provide power to the system from the Company's plant in downtown Nantucket. The units, installed between 1948 and 1978, range in size from 0.7 MW to 6.9 MW.

B. The Previous Siting Council Review

The Siting Council's review of Nantucket's previous forecast, in Docket 83-28, was unusual in that the decision was adopted in two stages. At an interim point in that proceeding, the Siting Council adopted a partial decision approving portions of the Company's forecast that were disposed of through settlements among all parties to the proceeding. ("Interim Decision in Docket 83-28"). In re Nantucket Electric Company, EFSC Docket 83-28, 12 DOMSC 155 (1985). Matters not addressed in the settlements were considered by the Siting Council in a second decision, which concluded that proceeding ("Decision in Docket 83-28"). In re Nantucket Electric Company, EFSC Docket 83-28, 13 DOMSC 1 (1985). In its decision, the Siting Council approved Nantucket's demand forecast, subject to conditions, and rejected the supply plan.

C. History of the Proceedings

Nantucket filed its Forecast on January 21, 1986. Worried Electric Consumers about Rates and Environment ("WECARE") filed a petition to intervene on February 24, 1986. On March 10, 1986, Nantucket filed a request that the Hearing Officer deny WECARE's petition to intervene. In a Procedural Order dated March 28, 1986, the Hearing Officer granted WECARE's petition, subject to conditions.

On April 11, 1986, the Siting Council conducted a pre-hearing conference to discuss the extent of and schedule for technical sessions and discovery. On April 15, 1986, the Company filed a request that the Hearing Officer reconsider WECARE's admission to the proceeding. In a Procedural Order dated April 28, 1986, the Hearing Officer denied Nantucket's request.

On June 3, 1986, WECARE filed an updated list of its members as required by the Hearing Officer's Procedural Order of March 28, 1986. On June 16, 1986, the Siting Council received letters from seven individuals, whose names had appeared among those on WECARE's list of members, requesting that their names now be removed from such list.

On June 2, 1986, the Company filed an appeal to all members of the Siting Council to seek clarification of the Siting Council's criteria for granting intervention generally, and request that the Siting Council review Docket 86-28 and dismiss WECARE for failure to meet requirements of intervention. On June 26, 1986, the Siting Council heard oral presentations by both parties to the proceeding, but, for lack of a motion by any member, did not consider as an agenda item the Company's request for dismissal of WECARE.

Meanwhile, in April, 1986, the Company requested and obtained a Siting Council subpoena to enable it to obtain from a former consultant to the Company data needed to support the Company's forecast. A technical session arranged at the pre-hearing conference was postponed pending receipt of the data, and on May 19, 1986 the Company notified the Hearing Officer that the data had been received.

Following the Company's appeal to the Siting Council to dismiss WECARE, the Hearing Officer scheduled a technical session for July 22, 1986 to resume the technical review. The Company again sought a postponement, and later, on August 5, 1986, filed a request to conduct discovery of WECARE with the twofold purpose of (1) exploring WECARE's make-up, organizational background and decision-making practices, and (2) more fully identifying WECARE's positions on issues in the proceeding. The Hearing Officer suspended the previously set discovery schedule and sought further clarifications of the Company's request for discovery in a Procedural Order dated August 8, 1986. On August 14, 1986, the Company provided the information requests to be answered by WECARE, if the Company's request for discovery was granted.

On August 25, 1986, the Company and WECARE jointly requested an eight-day extension for WECARE to object to the Company's discovery request of August 5 and 14, and later they sought continuances of the extension. The Hearing Officer allowed the extensions but, on October 3, 1986, notified the parties that the Hearing Officer intended to proceed with review of the Company's Forecast.

The Siting Council conducted technical sessions on the Company's Forecast on October 17 and 29, 1986.

On November 20, 1986, the Company and WECARE jointly requested an extension of unspecified duration to object to each other's discovery. On December 22, 1986, the Company and WECARE filed a settlement agreement, providing for the withdrawal of WECARE's intervention and discovery in the proceeding, and the withdrawal of the Company's discovery and related statements filed August 5 and 14, 1986.

On December 19, 1986, the Hearing Officer informed the parties that the Siting Council was closing the record in the proceeding. At that time the Hearing Officer entered 64 exhibits in the record, largely composed of the Company's Forecast and responses to information requests.

II. DEMAND FORECAST

A. Standard of Review: Demand Forecast

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 the foregoing, the Siting Council applies three standards in its review of demand forecasts. A demand forecast is reviewable, if the results can be evaluated and replicated by another person, given the same level of technical resources and expertise. A forecast is appropriate, if the methodology used to produce the forecast is technically suitable to the size and nature of the utility's system. A forecast is reliable, if the methodology instills confidence that the data, assumptions and judgments produce a forecast of what is most likely to occur. In re Boston Edison Company, 10 DOMSC 203, 209 (1984).

B. Overview of Forecast Methodology and Results

Nantucket continues to base its demand forecast on econometric models for three classes of sales -- residential, commercial and street lighting -- and for both winter and summer peak loads. The models range in format from a linear model for summer peak load, to double-log transformation models for winter peak load and commercial sales, to dynamic double-log transformation models for residential sales and street lighting sales (Forecast, P. 3-1 to 3-14).

Independent variables include heating degree days, average system-wide price, average residential heating customers, and various seasonal counts of total residential customers. In addition to August (peak season) and average monthly residential customers, the Company now has introduced January residential customers as a third total-customer variable, with specific applicability to the winter peak model. The Company continues to base its forecast of price largely on judgement. However, the Company now has implemented a statistically based method for forecasting total customers -- a method that regresses customer numbers with time (i.e., time trends) using several forms of bivariate curves (Forecast, P. 4-1 to 4-4).

The Company's forecast indicates that Nantucket's total energy requirements will increase from 63,226 megawatt hours ("MWH") in 1984 to 108,167 MWH in 1995, and summer peak load will increase from 14.4 MW to 25.9 MW over the same period. Average annual compound growth rates between 1984 and 1995 will be 5.0 per cent for total energy generation, 5.5 per cent for summer peak load and 2.4 per cent for winter peak load. The projected annual increases for average number of monthly customers over the same period are 5.1

per cent for total residential customers and 3.8 per cent for heating customers. Seasonally, the projected annual increase in total customers is 6.0 per cent for January and 4.3 per cent for August. (Forecast, pp. 4-13, 5-5, and Appendix B, Tables E-8 and E-11).

C. Compliance with Previous Conditions

In its previous decision in Docket No. 83-28, the Siting Council placed eight conditions on its approval of the Company's demand forecast.

Conditions 1, 2, 3 and 5 addressed customer projections. The present decision devotes substantial attention to the Company's progress in complying with these four conditions. See Section II-D-1. In summary, the Siting Council finds the Company prepared reviewable customer projections as required by Conditions 1 and 5, and adequately analyzed customer-population relationships as required by Condition 2. The Company failed, however, to develop customer forecast scenarios, as required by Condition 3. Two new conditions relating to customer projections are affixed to this Decision -- one addressing compilation of background data on population and visitation to enhance forecast reliability, and one reapplying the requirement that a scenario methodology be employed.

Conditions 4 and 6 concerned compilation of data on heating and non-heating customers and usage. The Siting Council finds the Company presented annual billing data on residential customers and usage from 1979 to 1984, disaggregated by heating and non-heating categories, as required by Condition 6 (Forecast, pp. 8-2 to 8-5). The Siting Council finds the Company presented heating and non-heating usage factors on a consistent basis, as required by Condition 4 (id).

Condition 7 required the Company to provide an analysis of the distribution of seasonal use profiles among residential customers, based on statistical samples from the years 1979, 1983 and 1985. The Company failed to perform the analysis, citing excessive cost, but noted that it had incorporated the number of January bills as a new independent variable in its winter peak model. A new substitute condition concerning seasonality of usage is affixed herein, requiring further tracking and analysis of January billing, with particular attention to usage patterns and trends for minimum bill customers during the month. See Section II-D-2.

Condition 8 required the Company to test winter peak load models reflecting actual winter usage by customers from both heating and non-heating purposes. In response, the Company added the January count of total residential customers, while also retaining average annual heating customers, as independent variables in the winter peak model. The Siting Council finds this approach complies with Condition 8, but notes that further tracking and analysis of billing data is required in connection with the seasonal use concerns addressed in Condition 7.

D. Evaluation of the Demand Forecast

1. Customer Projections

The Company's current forecast is based on customer numbers that, when compared over a long-term forecast horizon, are significantly higher than those in previous filings. Table 1 shows the projected annual additions of August customers developed in Nantucket's current and two previous filings.

TABLE 1

Annual Additions of August Customers, 1984-95
Past and Current Filings

Sub-Period	1981 Analysis	1984 Analysis	Current*
1984-88	+100/yr	+200/yr	+248/yr
1988-90	100	150	289
1990-93	50	150	324
1993-95	50	100	359

* Based on staff calculation of annual average for sub-period.

Source: Forecast, p. 4-6. In re Nantucket Electric Company, 13 DOMSC 1, 9 (1985).

Nantucket used time-trend bivariate models to develop these customer-number projections. Nine forms of model equations were tested for each of four annual average and seasonal customer counts.[1] For each customer count, the Company selected two to four equations as being the best, conceptually and statistically, then projected customer numbers over the forecast period using the selected curves, and then averaged the results to develop a single time-trend forecast for each customer count (Forecast, pp. 4-1 to 4-12).

The Company states that it chose the new customer projection methodology to satisfy the Siting Council's requirements that such forecasts be reviewable, appropriate and reliable (Exh. HO-29). The Siting Council finds that the Company has incorporated and documented statistically based models of customer projections. Thus, the Siting Council finds that the Company's methodology for customer projections now is reviewable.

However, the Siting Council remains concerned about the reliability and appropriateness of the customer forecast methodology. Nantucket has been unsuccessful in relating past customer trends to population trends, and thus continues to use a forecasting methodology not directly related to either seasonal or year-round population. In addition, Nantucket has not incorporated a scenario approach in its customer forecast, as ordered in the Siting Council's previous decision in EFSC 83-28.

As in previous filings, the Company did not use population trends as a factor in the Company's forecast methodology. The Company reports that it analyzed population-customer relationships and found them to be poor for predictive purposes, even for the January customer count which presumably would be most representative of year-round population (Forecast, p. 4-1). Citing data available through 1983, the Company stated that population has been fairly flat, between 5000 and 5500 residents, since 1974 (id).

While population-customer relationships would have to be established before population could serve as a reasonable determinant of future demand,

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[1] The customer counts include total average monthly bills, total August bills, total January bills, and average monthly bills to heating customers.

the Siting Council notes several facts regarding year-round population that warrant further attention to the applicability of this variable for predicting customers. First, more recent data available from the 1985 state census now indicate an upturn in population, to nearly 6000 residents (Exh. HO-DOC-4). Second, the Company acknowledges that it has not considered the possible distorting impact on customer-population relationships of trends in average household size, even though U.S. Census figures indicate that average household size in the United States has declined (Exh. HO-32). Third, the Company has not considered the possible distorting impact on customer-population relationships for January associated with minimum bills. Minimum bills make up a sizable component of the January customer count and presumably reflect in large part bills sent to owners of seasonal homes that are unoccupied or minimally occupied in January. See Section II-D-2.

To support its customer projections, the Company cites recent trends in housing construction and the formation of buildable lots, together with figures on the large stock of "approved" buildable lots (Exhs. HO-DOC-4; HO-30a). The Company also provided data on Island travel trends through 1983, but did not comment on the significance of such data for the forecast (Exh. HO-DOC-3).

The Siting Council finds that the Company's reliance on recent development trends, alone, is insufficient to support the sharply higher customer projections reflected in Table 1. In an island setting such as Nantucket, important constraints to long-term development exist and must be considered. First, there is the obvious constraint of the Island's finite land area. The 1985 Nantucket Annual Report notes a trend toward "encroachment of development on the Island's marginal type lands, containing significant wetlands areas" (Exh. HO-DOC-4). As for future growth, the Nantucket Board of Health recently adopted an ordinance effectively establishing a 40,000-square-foot minimum area for newly subdivided building lots (Exh. HO-2). Finally, the Company itself recognizes that standard demographic models, particularly a constant-growth exponential curve, have limitations in "a restricted geographical region such as Nantucket Island" (Exh. HO-4).

Yet, rather than temper the standard demographic approach to take land use constraints into account, the Company selected an approach that does just the opposite. The Company's forecast incorporates rates of annual residential customer growth that (1) are higher on average than those derived from the best-fit exponential curve, and (2) for the August count actually accelerate over the early and middle years of the forecast period, providing a pattern of annual growth even more expansive than that built into an exponential curve (Exh. HO-5; Forecast, pp. 4-6, 4-8, 4-10, 4-13).

When asked about the theoretical applicability of its customer forecast models, the Company noted that it has not used causal modeling "because the extrapolative approach has shown excellent fits" (Exh. HO-4). The Company further asserts that "when dealing with a short-term period such as 10 years..., the primary concern is with explanatory power (the fit)" (id).

This approach contravenes the Siting Council's standards for review of an electric company's demand forecast. An electric company must identify significant determinants of future demand and the means by which they were taken into account[2] (EFSC Rule 63.5[a][i]). In the case of econometrically based forecasts such as Nantucket's, the theoretical or empirical basis for functional form and variable selection must be provided (EFSC Rule 69.3[1]). Clearly, the Siting Council requires a forecast to reflect a reasonable range of relevant determinants in a way that is theoretically as well as statistically sound.

Given Nantucket Island's seasonal population and visitation levels, the Siting Council recognizes the difficulty of finding a readily accessible and consistent basis on which to justify future expectations for both year-round and seasonal customers. However, this difficulty does not justify the Company's extreme reliance on extrapolative techniques, without regard for whether past trends will continue or shift.

In light of the uncertainty about future customer numbers and the apparent absence of a reasonable and consistent basis for tracking and projecting seasonal trends, the Siting Council previously ordered the Company to incorporate scenarios in its forecast. The Siting Council still finds the approach of formulating a reasonable range of scenarios would force the

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[2] Suggested determinants include price of electricity and such driving variables as population, income and gross product. The Company's methodology includes price, but none of the suggested driving-variable determinants (EFSC Rule 63.5[b]).

Company to consider the principal element missing from its current forecast -- the qualitative underpinnings that help ensure the forecast is reliable.

Indeed, the Company itself provided, in the current review, a forecasting point of view similar in style to a scenario, when it stated that "comparisons [of forecasted trends] to [those of] the 1970's and early 1980's ignore the fact that these were periods of severe economic recession" (Exh. HO-31-C). The Company's assertion suggests the Company gives greater weight in supporting its forecast to a growth scenario based on sustained prosperity than to one based on a recurrence of recession. To determine that Nantucket's forecast is reliable, the Siting Council requires a more explicit recognition of scenarios near both ends of and within a reasonable spectrum and a well-reasoned statement of what forecast on that spectrum then should be chosen, and why.

The Siting Council therefore conditions its approval of the demand forecast, on three CONDITIONS relating to the Company's development and support of customer projections.

First, the Company in its next filing shall provide and discuss information, including the most up-to-date available data obtained directly from appropriate state or town agencies or travel facility operators, on changes over recent years: in year-round resident population; in travel to and from the Island; and, if available, on non-resident visitation, overnight room occupancy or overnight room capacity. The Company also shall provide and discuss any available projections of year-round population or other reasonable determinants of customer change that have been adopted or released for Nantucket Island for one or more forecast years, by any state, regional or local agencies since January 1, 1983.

Second, the Company in its next filing shall develop a minimum of two customer-forecast scenarios spanning a reasonable range of growth expectations for Nantucket Island. The Company shall also select a forecast that is the most reasonable among the scenarios evaluated by the Company and which is consistent with the Company's criteria for developing a reliable forecast and for any other planning purposes the Company may choose to consider. The Company shall fully describe its rationale for formulating such scenarios and for choosing the customer forecast it uses in its demand forecast from among such scenarios.

Third, the Company shall explicitly consider the direct incorporation of year-round population as a determinant of demand in all future filings.

2. Seasonality of Usage

In order to provide a more reliable customer count for purposes of the winter peak-load forecast, the Company for the first time has used the number of January bills as an independent variable (Forecast, p. 2-2). The Siting Council approves the use of a January count, finding such an approach consistent with the Company's use of August bills as an independent variable in the summer peak and commercial sales forecasts, as approved in past decisions.

The issue of possible distinctions in the usage patterns of year-round and seasonal customers -- a concern in the past decision -- again has been addressed in this review, with particular reference to the newly available count of January bills. The Company provided data on the issuance of minimum bills for its predominant residential rate class, showing the number and proportion of minimum bills by month and recent year-to-year trends in the number and proportion of minimum bills for the month of January[3] (Exhs. HO-34, HO-DOC-5). The Company has insisted, however, that it would be too expensive to conduct a more involved analysis of trends in seasonal use patterns or profiles among residential customers, as ordered in the Siting Council's previous decision (Forecast, p. 8-5; Exh. HO-8).

The data provided by the Company indicate to the Siting Council that many of the 882 minimum bills issued in January, 1986 to Class R customers represent homes that are unoccupied for much or all of January (Exh. HO-34).

The Siting Council is concerned that the Company's January customer count, used in the winter peak model, includes such a large proportion of apparently unoccupied seasonal homes. While no clear pattern emerges from the year-to-year data provided by the Company, clearly there is the potential for

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[3] Class R, the predominant class, includes controlled electric hot water customers with or without electric heat. The minimum monthly bill for the class is $15. In January 1985, the class accounted for 55 per cent of residential customers (Exhs. HO-DOC-5; HO-34).

January billings to seasonal homes to distort the relationship over time between customer numbers and usage levels, and between customer numbers and population.

The Company has cited its introduction of the January count of customers in explaining its refusal to undertake an analysis of the distribution of seasonal-use profiles, as ordered in the previous Siting Council decision (Exh. HO-8). While it supports Nantucket's use of the January count, the Siting Council finds the usefulness of the January count is significantly enhanced by the ability to separate out trends in issuance of minimum bills.

The Siting Council also notes that the ability to track minimum bills separately may shed new light on a trend cited in the previous Siting Council decision in connection with seasonal usage data, which showed a decline over time in total bills for August as a per cent of total monthly bills for the year. A related inference drawn in that decision -- that there may be a trend toward more off-season usage in seasonal homes -- is not as yet clearly supported by the new data on minimum bills developed in the current review. In re Nantucket, 13 DOMSC 1, 22 (1985).

Still, the Company's ability to track minimum bills reliably and easily extends only back to 1983, when computerized recording of such bills began (Exh. HO-34). The Siting Council finds that continued tracking and perhaps additional analysis of minimum-bill customers is an appropriate means to help resolve concerns about possible distinctions between year-round and seasonal customers with respect to usage patterns and trends.

As a CONDITION of the approval of this forecast, the Company in its next filing shall report year-to-year trends in January residential bills, and separate out the number of minimum bills issued to R Class customers, for the years 1983 to 1986. The Company shall discuss trends in the number and usage patterns of January minimum bill customers, as compared to other January customers, and make available to the Siting Council information on usage levels of January minimum bill customers for the years 1983 to 1986.

3. Price of Electricity by Customer Class

In the previous decision, the Siting Council requested that the Company consider disaggregating by major customer class the price term in its forecast models. In re Nantucket, 13 DOMSC 1, 15 (1985). The current forecast, however, continues to be based on a system-wide price of electricity. The Company states that it is reluctant to examine separate price terms in its next forecast, as well (Exh. HO-37).

In support of its position, the Company argues that it is inappropriate to "second guess the DPU in terms of the future allocation of system costs to the various rate classes" (id). The Company further believes disaggregation is unnecessary, since the system-wide term functions well in the models (id).

With regard to assumptions about future rates, the Siting Council requires that a Company's forecast methodology must explicitly consider and quantify responses to higher price levels and potential or actual changes in rate structure (EFSC Rule 69.2[4][f]). An appropriate forecast model must break out the price term by major class. The argument that system-wide price functions well does not dissuade the Siting Council that class-by-class prices would also function well and be more reliable in forecasting future sales based on the actual price-response relationships faced by ratepayers.

As a CONDITION of the approval of this forecast, the Company in its next filing shall test and as appropriate use sales forecast models based on past and assumed future prices of electricity broken out by major customer class.

4. Use of Dynamic Model Format

In its previous decision, the Siting Council considered the statistical correctness and overall appropriateness of the Company's use of dynamic double-log transformation models to forecast residential sales.[4] While making no findings with respect to statistical correctness, the Siting Council did advise the Company to justify any future use of such models -- either by demonstrating a significant gain in explanatory power over alternative models or by further addressing the statistical concerns raised in that review. In re Nantucket, 13 DOMSC 1, 20-27 (1985).

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[4] In the Company's model, the dependent variable (sales per customer) lagged one year was used as an independent variable. In the previous review, an intervenor argued that the lagging effect is reasonable in relation to only one of the independent variables -- price.

The current forecast for residential sales is based on essentially the same model format used in the previous forecast (Forecast, p. 3-2). However, the Company defended its current forecast by presenting a comparison of the backcasted fit both with and without use of the lagged dependent variable (Exh. HO-12). The comparison shows that the standard error of regression would increase 43 per cent, and R-squared would decrease from .985 to .967, without use of the lagged dependent variable (id).

The Siting Council finds in this case that the gain in explanatory power justifies the Company's decision to utilize the dynamic model format. However, when the Company is in a position to develop separate forecast models for its heating and non-heating customers,[5] the Company should test alternative specifications that avoid possible lag structure problems.

5. Conclusion

The Siting Council finds that Nantucket's 1986 forecast of demand is reviewable. The Siting Council finds that the demand forecast is minimally appropriate and reliable, and that more reliable methodologies for projecting customer numbers and incorporating class-by-class price are needed. Therefore, the Siting Council approves the demand forecast subject to the four conditions discussed in sections II.1, II.2 and II.3.

III. THE SUPPLY PLAN

A. Standard of Review: Supply Plan

In keeping with its mandate to "provide a necessary power 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 a 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. In re Cambridge

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[5] The Company has disaggregated data on heating and non-heating customers back to 1979 only, and thus does not have an adequately long data base yet.

Electric Light Company, et al, 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. In re Cambridge Electric Light Company, et al, 15 DOMSC ___, 7 (1986). The Siting Council also evaluates whether a supply plan minimizes the long-run cost of power subject to trade-offs with adequacy, diversity, and the environmental impacts of construction and operation of new facilities. In re Boston Edison Company, 7 DOMSC 93, 146 (1982). The Siting Council's evaluation of the long-run cost of the supply plan generally focuses on a company's supply planning methodology. In re Cambridge Electric Company, et at, 15 DOMSC ___, 10-12, 39-40 (1986). Finally, the Siting Council reviews utility demand management programs, cogeneration and small power production projects on the same basis as they treat new conventional bulk power facilities and power purchases, when those utilities attempt to develop an adequate, diverse, and least-cost supply plan.[6] In re Cambridge Electric Light Company, et al, 15 DOMSC ___, 7, 27, 40 (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' supply plans 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 utility 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. In re Cambridge Electric Light

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[6] 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.

Company et al, 15 DOMSC ___, 7-9 (1986); In re Fitchburg Gas & 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 long-run. In re Cambridge Electric Light Company, et al, 15 DOMSC ___, 8 (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 can provide adequate supplies in the short-run, that company must then demonstrate that it operates pursuant to a specific action plan guiding it in drawing on alternative supplies should necessary projects not develop as originally planned. Id., pp. 8-9, 18-24, and 41. The definition of short-run must be determined on a company-by-company basis so that it may vary according to the shortest-lead-time resource(s) a given company can control and reliably place in service to meet need in a timely and cost-effective manner. Id., pp. 8 and 18-19.

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 energy and power resources over all forecast years. THe Siting Council recognizes that the latter 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 generating 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. 9 and 24-31.

B. Overview of the Supply Plan

The Company's supply plan includes a capacity expansion plan and a discussion of the Company's efforts with respect to conservation, load management and renewable energy sources. As in previous filings, Nantucket's capacity expansion plan portrays the size and timing of expected future capacity additions, under alternative assumptions of 3.6 MW and 6.0 MW capacity increments (Forecast, pp. 7-2 to 7-3). The 3.6 MW facility currently is shown as a proposed facility in the Forecast. With respect to demand-side management and renewable energy, the Company highlights past accomplishments -- notably the controlled hot water heater program and the independently owned 270-kilowatt wind farm -- and estimates potential savings from two of the programs identified as part of a stipulated plan for conservation and load management previously approved by the Siting Council (Forecast, p. 6-1 to 6-15).

Nantucket currently has generating capacity totalling 20.0 MW. Under the Company's single-contingency reserve requirement, previously approved by the Siting Council, the Company must maintain a reserve capacity equal to its largest unit, or 6.9 MW. In re Nantucket, 12 DOMSC 155, 161 (1985). Expressed as a percentage of the maximum load that can be reliably served, the reserve margin requirement currently is 53 per cent.

The Company has failed to have adequate reserve capacity to meet its summer peak need since 1982 and its winter peak need since 1984/85 (Forecast, Appendix B, Table E-17). The Company's forecast initially showed the planned addition of a 3.6 MW generating unit by Summer, 1987, in order to restore adequate reserves to meet the summer peak need for 1987, and to meet the winter peak need from 1987/88 through 1993/94 (id). The Company no longer assumes that the facility will be on line for Summer, 1987 (Exh HO-23). Indeed, in 1986 the Company acquired two emergency generators, with total capacity of 2.4 MW, to help meet any capacity shortfalls in the near term (Exh. HO-21). Even counting this emergency capacity, the Company's supply plan provides inadequate capacity to meet projected peak load and reserve requirements in Summer, 1987, without the planned 3.6 MW generating facility. If the planned facility is in service by Summer, 1988, the Company will need to propose and implement still additional supply resources to meet its needs for Summer, 1988 through the end of the Forecast period (Forecast, Appendix B, Table E-17).

C. Compliance with Previous Condition

The Siting Council placed one condition on its approval of a stipulation regarding conservation, rate structure and load-management, addressed as part of the Company's supply plan in the Interim Decision in Docket 83-28. The condition required the Company to report in its next filing on its further evaluations, plans and programs concerning conservation, rate structure and load management. In re Nantucket, 12 DOMSC 155, 170 (1985). The Siting Council finds that the Company presented further evaluations, and thus complied with this condition. See Section III-E-2.

D. Adequacy of the Supply Plan

1. Adequacy in the Short-Run

To establish a short-run planning period or horizon, consistent with Section III-A, supra, the Siting Council determines the lead time necessary for obtaining supplies that are under the Company's control. The Company's supply plan includes only diesel generating facilities in the 3.6 to 6.0 MW size range. See Section III-B. As the Company has no other specific supply options, the Siting Council finds that the lead time for installing a 3.6 to 6.0 MW diesel generating facility is a reasonable basis for establishing the short-run planning horizon for Nantucket.

The evidence indicates this lead time to be five years, based on the Company's actual experience in putting the currently planned facility in place. The Company first proposed adding additional generating capacity to its existing 20.0 MW system as part of its 1983 forecast, filed in May, 1983. In re Nantucket, 12 DOMSC, 155, 157 (1985). In the nearly four years since that decision, the Company has been pursuing necessary regulatory approvals. The Company maintains that it cannot place an order for the facility until all regulatory approvals are obtained, and that an additional eleven months will be required for the facility to be put on-line after an order is placed. Id., p. 164.

It now appears unlikely that the planned facility can come on line until Summer, 1988 at the earliest -- five years after the Company first indicated its intent to build it.[7] Thus, the Company's short-run planning horizon must be based on this five-year lead time.

Accordingly, the Siting Council finds that Nantucket's short-run planning horizon extends for five years, through Winter, 1991/92. Based on the Company's own expectation that it cannot install its planned generation facility by Summer, 1987, and that the Company will need to plan and install additional capacity beyond the currently planned unit by Summer, 1988 (See Section III-B) the Siting Council also finds that Nantucket has inadequate supplies for all the years falling within Nantucket's near-term planning horizon.

The Siting Council ORDERS the Company to inform the Siting Council by June 1, 1987 of the Company's progress in obtaining necessary approvals for and implementing the planned generating facility.

2. Contingency Action Plans

Nantucket projects that it would experience a supply deficiency of 3.6 MW without the planned 3.6 MW facility in place this summer, if its largest generating unit goes out during peak load (Exh. HO-23). With the planned 3.6

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[7]The Company has cited increased burdens and delays associated with various regulatory agency reviews as the major factor preventing timely capacity expansion. The Company also has singled out, specifically, the role of organized opponents in delaying its expansion plans through interventions and other participation in such reviews (Exhs. HO-24; HO-42). The Company attributes the delays in completing state-level environmental reviews to "the presence of WECARE in various agency proceedings involving the Company" (Exh HO-42).

The Siting Council rejects the Company's reason for the delay in obtaining environmental permits. The Company must be accountable for accommodating legal intervention or other public participation in administrative proceedings (as part of its planning process).

As for the future, the Company notes that it will rely on the expertise of independent consulting firms to meet environmental permit requirements, and thus anticipates meeting such requirements in a timely and expeditious way (id). As use of consultants represents a continuation of past practices, the Siting Council cannot assume that a reduction in licensing time will occur in the absence of changes in the Company's own planning and oversight function.

MW facility on line next summer, Nantucket's supply plan resources still would be 1.0 MW short (id). If the on-line date of the proposed facility is delayed beyond Summer, 1988, however, the 1988 peak load deficiency would jump to 4.6 MW.

The Company installed 2.4 MW of emergency generating capacity in 1986 to help address the projected deficiencies (Exh. HO-21). The Company also has had in place for a number of years an outage contingency plan, which provides as needed for (1) shedding of the boat basin and cable television amplifier, (2) voluntary shedding of customers that have emergency generating capability, and (3) rotating service cutoffs among the system's four circuits. In re Nantucket, 12 DOMSC 155, 166 (1985).

When asked to document agreements it may have with larger customers regarding the contingency plan, the Company stated that the plan is based on long standing verbal agreements with such customers (Exh. HO-39). The Siting Council finds that verbal agreements are not appropriate as part of a strategy to cope with potential shortfalls, particularly as the only resort other than mandatory load shedding.

In other decisions, the Siting Council has found that mandatory load shedding is unacceptable, and that its avoidance is a grounds for justifying need for new facilities. In re Cambridge Electric Light Company et al, 15 DOMSC ___, 17, 20, 23 (1986); In re Boston Edison Company, 13 DOMSC 63, 70-73 (1985). Therefore, the Siting Council finds the Company's short-run contingency action plan is inadequate.

Accordingly, the Siting Council ORDERS that, on or before June 1, 1987, the Company provide an update on its contingency action plan for 1987. In addition, as part of its next filing, the Siting Council ORDERS the Company to provide an update on its contingency action plan for 1988. Each of the updates should include documentation of any firm load shedding agreements that the Company expects to rely on in the event of a single-contingency supply deficiency under peak load conditions. The Company also should set out and explain the order in which it would implement load shedding and rotating service blackouts.

3. Adequacy in the Long-Run

The Company's long-run planning time frame encompasses the period from Summer, 1992 through Winter 1995/96. During this period, the Company contemplates but does not specifically propose building additional diesel generating facilities in the 3.6 to 6.0 MW size range.

Based on the Company's analysis in this proceeding, the Company's long-run needs could be met through the installation of an additional three 3.6 MW units or two 6.0 MW units, beyond the facility that is currently proposed (Forecast, pp. 7-3 to 7-4). The Company also asserts that the proposed airport site could accommodate up to four 3.6 MW units (Exh. HO-17).

Based on the record in this proceeding, however, the Siting Council finds that the Company has not presented a plan for meeting its forecasted customer and reserve requirements in the long-run. Further, the Company has not provided evidence of its long-run supply planning process, which is required to establish adequacy of supply in the long-run. As such, the Siting Council finds that Nantucket has failed to demonstrate it has an adequate supply plan in the long-run.

E. Least-Cost, Least-Environmental-Impact Supply

In its review of the Nantucket's supply plan in the previous decision, the Siting Council rejected the Company's supply plan for its failure to explore the process the Company used to determine its future resource mix and to locate its capacity additions. In re Nantucket, 13 DOMSC 1, 33-34 (1985).

In the current filing, the Company has not identified any steps it has taken or plans to take to change its planning approach with respect to how the Company analyzes cost and environmental issues, or incorporates demand-side management in its resource plan. In this review, the Siting Council focuses on two facets of the Company's planning approach: (1) the approach to expanding capacity; and (2) the approach to integrating consideration of capacity expansion and demand-side management.

1. Capacity Expansion

The Company first proposed the installation of additional generating capacity at a site near Nantucket Airport in May, 1983. In re Nantucket, 12 DOMSC 155, 162 (1985). The Company provided information to the Siting Council concerning the Company's evaluation of possible sites for such capacity. The Company's siting process for the proposed capacity addition has included both a screening analysis to pinpoint an initial selection of feasible sites, and more detailed analysis to choose the best site (Exhs. HO-DOC-14; HO-17).

In its previous review, the Siting Council approved Nantucket's need to install an additional 3.6 MW of capacity at an undetermined site. In re Nantucket, 12 DOMSC 155, 170 (1985). The Siting Council, however, rejected the Company's overall supply plan, including the Company's general approach for siting new or relocated capacity, based on a lack of evidence concerning the existence of an appropriate long-term planning process. In re Nantucket, 13 DOMSC 1, 34 (1985).

In the current review, the Siting Council evaluated how the Company planned and evaluated the siting of the proposed generating facility. The Company first conducted a screening analysis to determine whether consideration of alternative sites to the existing plant were appropriate, and if so which sites (Exhs. HO-DOC-14; HO-17). The Siting Council finds the Company acted reasonably in deciding to investigate possible alternative sites to the existing in-town site, and employed a reasonable screening approach to identify the most feasible prospective sites (id). The Siting Council further finds that the Company acted reasonably in focusing on sites that provide flexibility for siting additional generation, beyond the proposed facility, should the Company later decide to pursue such installation (Exh. HO-17).

The Company's planning process with respect to siting its capacity additions raises questions directly relating to the Siting Council's standards for minimum environmental impact and minimum cost. However, because a failure by Nantucket to adequately anticipate environmental and cost concerns can lead to delays in implementing capacity expansion for Nantucket, these additional concerns also relate to the Company's ability to secure an adequate supply of energy (See Section III-D). The Siting Council therefore treats these issues in the context of determining whether Nantucket has provided a reliable, least-cost, least-environmental-impact energy supply.

a. <u>Environmental Issues</u>

The record provides little evidence regarding the Company's analysis of how various environmental concerns affect long-run siting scenarios involving two or more generating facilities. Particularly, the Company has not shown that it can comply with air quality requirements for capacity expansion (Exh. HO-47). While the Company asserts that as many as four 3.6 MW units could be located at the airport site without air quality problems, the Company has not received any environmental permits for the Company's proposed unit which would confirm that assertion (<u>id</u>). Further, the Company asserts that fuel for up to four 3.6 MW units can be transported by truck to the airport site and stored on that site, but provides no supporting analysis (Exh. HO-41). The record is not conclusive regarding whether safety, nuisance and environmental considerations place constraints on the volumes of diesel fuel that can be so hauled.

For Nantucket to demonstrate in future filings that it has a planning process that ensures a least-cost, least-environment-impact energy supply, the Siting Council finds that Nantucket's supply plan must include a discussion of how the Company takes into consideration long-run environmental constraints, including but not limited to air quality and fuel transport, in its capacity expansion plans over the forecast period.

b. <u>Cost and Operating Efficiency</u>

With respect to siting a new generating plant at the airport, the Company has acknowledged some additional up-front costs in separating its generating plant locations. The Company asserts there will be no long-term costs attributable to either increased line losses or other operational problems in managing an isolated facility (Exhs. HO-16; HO-38).

However, the record indicates to the Siting Council that there are deficiencies in the Company's planning process with respect to evaluating costs associated with facility siting.

First, while the Company has been engaged over the last two years in extensive environmental analysis of its proposed capacity expansion, it has failed to provide any updated cost estimates or other evidence of the cost implications of conclusions in its environmental studies (Exh. HO-14). The Siting Council finds that evidence of the Company's continuing failure to integrate cost and environmental analysis in its capacity expansion planning cannot support a finding that the Company is applying a least-cost planning approach.

Second, there is little evidence of the Company's consideration of either short-term or long-term transmission system changes associated with the siting of new base-load capacity along what is now a distribution circuit four miles from the existing generating plant. The Company states that no load flow studies have been performed and asserts that changes in line losses probably will be minimal (Exh. HO-38). Based on the evidence, the Siting Council finds the Company has inadequately considered transmission system implications in its capacity expansion planning process -- even in the context of the single 3.6 MW facility now being proposed.

Third, beyond the question of where additional capacity should be sited, there is little evidence of the Company's consideration of options for replacing older units at the existing plant, at either the current site or the airport site. The Company states that its present reserve supply deficiency precludes actively considering any replacement or relocation of existing capacity to the proposed new airport site (Exh HO-18). While implementation of replacement and relocation options may be difficult over the next several years, the Company nonetheless should expand its planning to include any such options in the Company's forecast, even if only in a long-run context.

For Nantucket to demonstrate an adequate and least-cost planning process in future filings, the Siting Council finds that Nantucket's supply plan must include discussion of short-run and long-run transmission and unit-relocation considerations as part of its planning process for capacity expansion.

2. Demand Management Plans

In reviewing other companies' supply plans, the Siting Council has ordered companies to demonstrate their consideration of demand-side management as part of an acceptable least-cost planning approach. In re Com/Electric, 15 DOMSC _____, pp. 32-35 (1986). Demand-side management also may contribute to achieving a least-environmental-impact plan.

The Company has implemented and fine-tuned a controlled hot water program, which the Company estimates is deferring 2.65 MW of load for the System (Forecast, p. 69). However, despite the 1985 approval by the Siting Council of a set of stipulated programs for conservation and load management, the Company has not implemented any new programs consistent with the stipulation, nor determined that detailed economic analyses are justified with respect to any such programs (Forecast, pp. 6-1 to 6-11). See In re Nantucket, 12 DOMSC 155, 167-169 (1985).

In the current filing, the Company has reassessed the stipulated demand-side measures, as approved by the Siting Council, and concluded that none of the measures would be effective in deferring future capacity needs (Forecast, pp. 6-1 to 6-11). The Company asserts that several programs addressing thermal needs would not be effective because at time of summer peak load, heating usage is not a factor and hot water usage is already shifted off peak by the widely used control program (Forecast, p. 6-4). The Company asserts that price inelasticity precludes significant savings from two conservation programs directed at commercial customers (id.). The Company acknowledges that two remaining programs -- discounts for energy-efficient light bulbs and rebates for energy-efficient refrigerators and freezers -- would reduce future capacity requirements, but argues that the reductions would amount to less than one per cent of forecasted 1987 peak load and thus be relatively insignificant in affecting the timing of capacity increments (Forecast, p. 6-4 to 6-8; Exh. HO-43).

The Siting Council considers the Company's reasoning on these issues to be unpersuasive. For example, the Company presents long-term commercial customer usage trends as evidence that such customers are not conserving, but does not consider that there may be trends in other factors (eg., floor space) that potentially affect average customer usage (Forecast, p. 6-3). With respect to programs estimated to provide potential capacity savings that are small relative to the increments in which capacity is added, the Company has not provided evidence of either a total lack of benefit, or a cost per unit of benefit exceeding that of alternative resource options, such that dropping such programs from further consideration would be justified.

Further, in evaluating the ability of demand-side management to help meet seasonal peak needs, the Company focuses exclusively on summer peak and ignores all other seasons. When placed in the context of the Company's capacity expansion plans and the operation of its generating plant, this single-season analysis of demand management benefits is too limited. For example, the Company has provided estimates of annual reserve capabilities over the next three years for each of the four seasons of the year (Exh.

HO-23). However, while the Company determined winter and summer capabilities based on the unscheduled loss of the Company's largest unit, the spring and fall capabilities were determined based on the scheduled loss of one large unit for regular maintenance combined with the unscheduled loss of a second large unit. According to the Company's evidence, shown in Table 2, a double-contingency loss in the spring or fall would be of more concern than a single-contingency loss in the summer. Therefore, the Company's supply planning for both demand management and capacity expansion must incorporate analyses of how resource options fit into a plan to meet customers' requirements throughout the year. (This issue also relates to the Company's ability to ensure an adequate supply of energy, See Section III.D).

TABLE 2

Reserve Capability by Season

	SINGLE CONTINGENCY SURPLUS OR DEFICIENCY*		DOUBLE CONTINGENCY SURPLUS OR DEFICIENCY*	
YEAR	SUMMER	WINTER	SPRING	FALL
1987/88	-3.64MW	+2.18MW	-4.23MW	-5.90MW
1988/89	-0.99	+1.78	-1.30	-3.06
1989/90	-2.02	+1.28	-2.02	-3.89

* Based on Unit 7 being out of service in Summer or Winter, or Unit 7 and Unit 6 being out of service in Spring or Fall. Assumes proposed Unit 8 will be on line by Winter, 1987/88.

Source: Exh. HO-23.

Therefore, the Siting Council finds that Nantucket's evaluation of demand management's potential economic, environmental and operating benefits and cost to the system are biased and inadequate. Accordingly, the Siting Council finds that Nantucket's supply plan fails to demonstrate that it can ensure a least-cost, least-environmental-impact energy supply for Nantucket's customers.

The Siting Council ORDERS the Company in its next filing to update its analysis of specific demand-side measures in order to determine which are most cost-effective and which should be implemented. This update should be based on new audit information and the Company's further research. Cost information should be provided even for measures that appear to offer only small capacity savings. Cost analyses should be presented in such a way that the Company can compare the cost to the system of implementing demand management against the cost to the system of adding equivalent capacity and/or producing energy over the lives of the demand and supply side options.

E. Conclusion

The Siting Council finds that the Company's supply plan is inadequate based on supply deficiencies within the Company's short-run planning horizon, extending through Winter, 1991/92. As a result, the Siting Council has required the Company to report on its progress in implementing the planned 3.6 MW facility, and to update its outage contingency plan (See Sections III-D-1).

In its review of the Company's planning process, the Siting Council finds that the Company's approach to analyzing a variety of siting concerns is reasonable as far as the one currently planned 6.5 MW facility is concerned. However, the Siting Council has identified some deficiencies with respect to planning and implementing the proposed facility -- most notably the severe delays in obtaining needed regulatory approvals.

In addition, the Siting Council finds that the Company's planning process is flawed with respect to (a) adequately exploring cost and environmental issues associated with siting facilities as part of a long-run generation expansion plan and (b) intergrating demand-side management on an equal footing with supply-side options. Therefore, the Siting Council concludes that the Company's planning process does not ensure that the Company's customers will have a least-cost, least-environmental-impact energy supply.

Accordingly, the Siting Council rejects the Company's supply plan.

The Siting Council ORDERS the Company in its next filing to comply with the following two additional CONDITIONS, concerning the overall scope and content of supply plans.

First, the Company shall present specific plans for meeting all forecasted peak-load requirements in the short-run. Such plans should include information on the sizing, timing, siting and costs for any proposed capacity expansion, and expected capacity and energy savings and costs for any demand-side management. The Company must demonstrate that, in developing those plans, it has explored a reasonable range of demand-side management and generation expansion options and has evaluated them on an equal basis.[8]

Second, the Company shall provide a discussion of its long-run supply planning process, including all approaches to changing the type, size and location of the Company's generating plant and integrating demand-side management measures into the Company's supply plan. The Company should explain how its planning process includes consideration of long-run environmental constraints, transmission system issues under split-plant operation, and options for capacity relocation under a split-plant configuration. The Company also should explain how its planning process includes consideration of objectives for establishing optimal reserve capacity criteria for different times of the year.

IV. DECISION AND ORDER

The Siting Council hereby APPROVES the demand portion and REJECTS the supply portion of the Nantucket Electric Company's Third Long-Range Forecast, subject to the following conditions. Accordingly, it is ORDERED:

1. That, on or before June 1, 1987, the Company shall inform the Siting Council of the Company's progress in obtaining necessary approvals for and installing the planned facility.

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[8] See Footnote 6.

2. That, on or before June 1, 1987, the Company shall provide an update on its contingency action plan for 1987. The update should include documentation of any firm load shedding agreements that the Company expects to rely upon in the event of a single- contingency supply deficiency under peak load conditions. The Company should also set out and explain the order in which it would implement load shedding and rotating service blackouts.

In the next Forecast, to be filed on or before November 1, 1987, it is FURTHER ORDERED:

3. That the Company provide and discuss information, including the most up-to-date available data obtained directly from appropriate state or town agencies or travel facility operators, on changes over recent years: in year-round resident population; in travel to and from the Island; and, if available, on non-resident visitation, overnight room occupancy or overnight room capacity. The Company also shall provide and discuss any available projections of year-round population or other reasonable determinants of customer change that have been adopted or released for Nantucket Island for one or more forecast years, by any state, regional or local agencies since January 1, 1983.

4. That the Company develop a minimum of two customer-forecast scenarios spanning a reasonable range of growth expectations for Nantucket Island. The Company shall also select a forecast that is the most reasonable among the scenarios evaluated by the Company and which is consistent with the Company's criteria for developing a reliable forecast and for any other planning purposes the Company may choose to consider. The Company shall fully describe its rationale for formulating such scenarios and for choosing the customer forecast it uses in its demand forecast from among such scenarios.

5. The Company explicitly consider the direct incorporation of year-round population as a determinant of demand in all future filings.

6. That the Company report year-to-year trends in January residential bills, and separate out the number of minimum bills issued to R Class customers, for the years 1983 to 1986. The Company shall discuss trends in the number and usage patterns of January minimum bill customers, as compared to other January customers, and make available to the Siting Council information on usage levels of January minimum bill customers for the years 1983 to 1986.

7. That the Company test and as appropriate use sales forecast models based on past and assumed future prices of electricity broken out by major customer class.

8. That the Company shall provide an update on its contingency action plan for 1988. The update should include documentation of any firm load shedding agreements that the Company expects to rely upon in the event of a single- contingency supply deficiency under peak load conditions. The Company should also set out and explain the order in which it would implement load shedding and rotating service blackouts.

9. That the Company update its analysis of specific demand-side measures in order to determine which are most cost-effective and which should be implemented. This update should be based on new audit information and the Company's further research. Cost information should be provided even for measures that appear to offer only small capacity savings. Cost analyses should presented in such a way that the Company can compare the cost to the system of implementing demand management against the cost to the system of adding equivalent capacity and/or of producing energy over the lives of the demand and supply side options.

10. That the Company present specific plans for meeting all forecasted peak-load requirements in the short-run. Such plans should include information on the sizing, timing, siting and costs for any proposed capacity expansion, and expected capacity and energy savings and costs for any demand-side management. The Company must demonstrate that, in developing those plans, it has explored a reasonable range

of demand-side management and generation expansion options and has evaluated them on an equal basis.

11. That the Company provide a discussion of its long-run supply planning process, including all approaches to changing the type, size and location of the Company's generating plant and integrating demand-side management measures into the Company's supply plan. The Company should explain how its planning process includes consideration of long-run environmental constraints, transmission system issues under split-plant operation, and options for capacity relocation under a split-plant configuration. The Company also should explain how its planning process includes consideration of objectives for establishing optimal reserve capacity criteria for different times of the year.

William S. Febiger

William S. Febiger
Hearing Officer

UNANIMOUSLY APPROVED by the Energy Facilities Siting Council on April 2, 1987 by the members and designees present and voting: Sharon M. Pollard (Secretary of Energy Resources); Fred Hoskins (for Joseph D. Alviani, Secretary of Economic and Manpower Affairs); Stephen Roop (for James S. Hoyte, Secretary of Environmental Affiars); Stephen Umans (Public Electricity Member); Madeline Varitimos (Public Environmental Member); Joseph W. Joyce (Public Labor Member). Ineligible to vote: Dennis J. LaCroix (Public Gas Member). Absent: Sarah Wald (for Paula W. Gold, Secretary of Consumer Affiars and Business Regulation); Elliot J. Roseman (Public Oil Member).

Sharon M. Pollard

Sharon M. Pollard, Chairperson

April 10, 1987

Date

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).