Decisions And Orders

Massachusetts Energy Facilities Siting Council

Volume 9

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COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition) of the Boston Gas Company and) Massachusetts LNG, Inc., for) Approval of a Supplement to a) Long-Range Forecast of Gas) Resources and Requirements:) 1982 through 1987)	E.F.S.C. No. 82-25

FINAL DECISION

Paul T. Gilrain, Esq.
Hearings Officer
November 12, 1982

On the Decision:
George Aronson
Staff Economist

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I. INTRODUCTION

The Council herein conditionally APPROVES the First Supplement to the Second Long-Range Forecast of Gas Needs and requirements of the Boston Gas Company et al. ("Boston Gas" or "The Company"). This decision is divided into six sections, each discussing, in turn, the salient aspects of the adjudication of the forecast. Following this introduction, we will describe the Company and its characteristics in Section II; the history of the adjudication in part III; evaluate the forecast of sendout in Section IV; assess the adequacy of the Company's supply plan in Section V, and finally, issue our Decision and Order in Part VI.

II. BACKGROUND OF THE COMPANY

Boston Gas is engaged in the distribution and sale of natural gas to residential, commercial and industrial customers in its service area which includes the City of Boston and 73 other eastern and central Massachusetts communities. A breakdown of the Company's firm customers is shown in Table I. In addition, the Company is the sole supplier of gas to the Wakefield Municipal Gas Company and a number of customers who are on an interruptible rate schedule. The actual total sendout for heating season and non-heating season for the last two years is shown in Table 2.

The Company has one subsidiary, Massachusetts LNG, Inc., which holds long-term leases of two LNG facilities. Since 1929, all of Boston Gas's capital stock has been held by Eastern Gas and Fuel Associates ("Eastern"), which is headquartered in Boston. Eastern, in turn owns

36.8% of the outstanding stock of Algonquin Energy, ("Algonquin"), Inc., parent company of Algonquin Gas Transmission Company ("AGT"), Boston Gas' largest supplier of pipeline gas. Algonquin SNG, Inc. is another subsidiary of Algonquin, which produces synthetic natural gas from naptha. In addition, Boston Gas owns 7.52% of the outstanding stock in Boundary Gas, Inc., a close corporation formed to purchase and import natural gas from Canada.

Boston Gas service area is actually divided into eight operating divisions, six of which are physically isolated from each other except for the Tennessee Gas Pipeline Company's pipeline. The map on Table 3 delineates these divisions. This divisional separation is addressed in detail in Section V, infra.*

Table 1

Boston Gas Company

NUMBER OF CUSTOMERS WITH FIRM SERVICE

	1980-81	1981-82
Residential with Gas Heating	227,900	237,846
Residential without Gas Heating	219,882	211,908
Commercial and Industrial, Firm	33,728	34,099

* Norwood is a physically isolated division, connected to the Boston Division only by the AGT pipeline. However the Company has considerable flexibility to make additional quantities of gas available to Norwood through the its Norwood AGT take station as it is the first Boston Gas take station on AGT's pipeline and AGT allows this flexibility without imposing a penalty surcharge. Therefore, we will consider Norwood as a part of the Boston/Norwood division.

Table 2

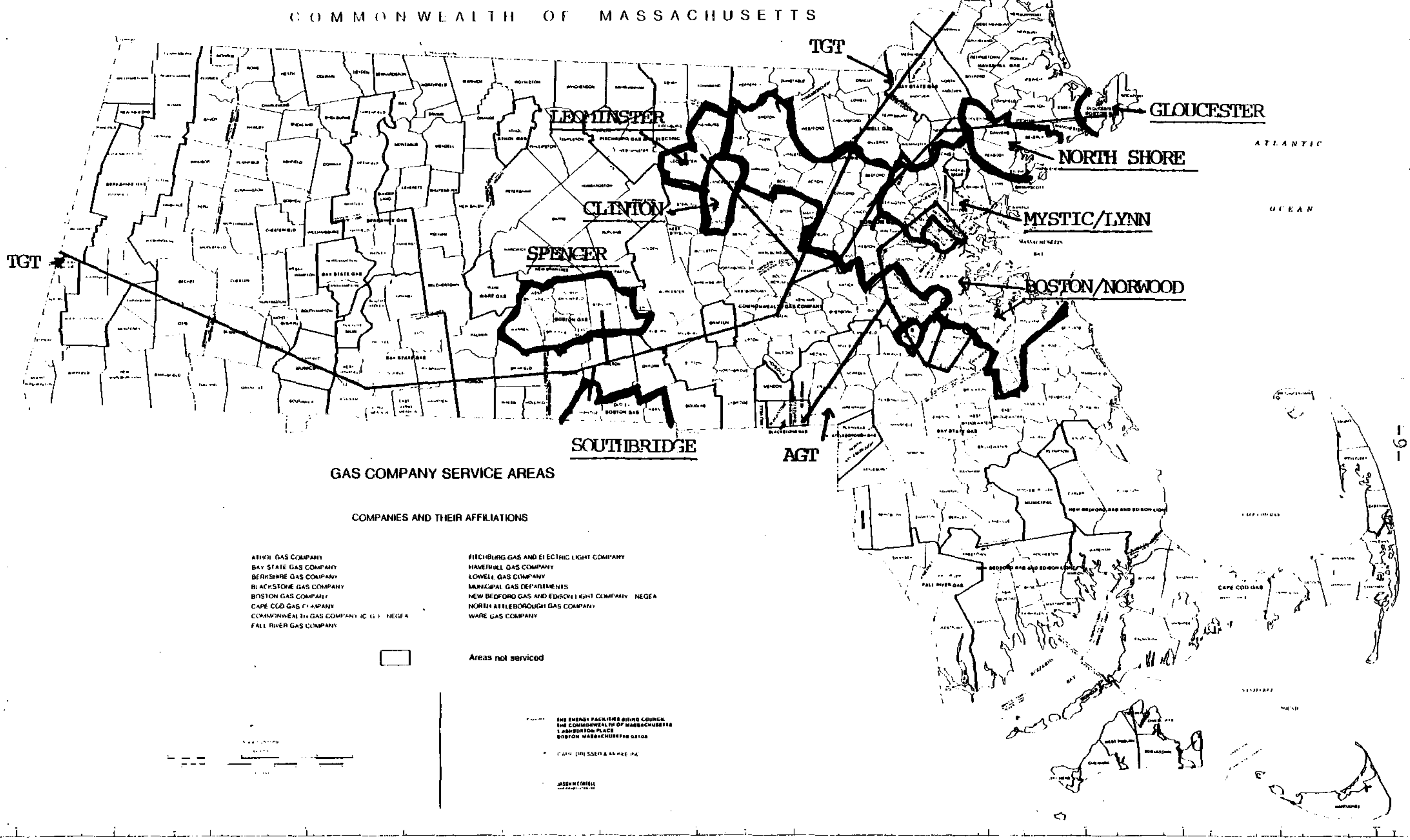
Boston Gas Company

ACTUAL SENDOUT BY CLASS

	1980-81 Heating Season	1980-81 Non-Heating Season	1981-1982 Heating Season	1981-1982 Non-Heating Season
Residential with Gas Heat	23,511.5	9,409.7	22.617.4	9,433.7
Residential Without Gas Heat	2,500.1	2,739.8	2,371.9	2,508.5
Commercial & Industrial, Firm	15,440.8	8,474.9	15,428.0	8,495.0
Wakefield Municipal Gas	220.8	111.6	244.6	122.4
Interruptible	4,014.2	6,995.5	5,831.0	7,619.0
Wholesale Sales for Resale	118.5	337.7	0.0	50.0
Company Use and Losses	4,063.0	49.0	5,969.0	86.0
TOTAL	49,868.9	28,118.2	52,461.9	28,314.6
TOTAL FIRM	45,736.0	20,785.00	46,630.9	20,645.6

Source: Tables G-1 - G-5

Table 3
Boston Gas Company
SERVICE DIVISIONS



III. HISTORY OF THE PROCEEDINGS

Boston Gas and Massachusetts LNG. Inc. filed timely their First Supplement to their Second Long-Range Forecast on July 16th, 1982. The Company twice amended this filing in August 1982 to correct errors in supply tables and to propose the construction of a Liquid Propane/Air facility in their Spencer division. Notice of intent to conduct an adjudicatory proceeding was published in a number of newspapers and posted in the city and town halls of each city and town within the Company's service area on July 26th, 1982.

Prior to this filing, the Company met with Council staff on three occasions pursuant to Condition number 9 of the Council's last Decision and Order.[1] During these meetings the Company and Council staffs discussed how the Company could best respond to the eight other conditions placed on it by the Council in that decision. As a result of those meetings, the Company made a good faith attempt at compliance; the substantive aspects are discussed in passim. A memorandum to file outlining the particulars of the Company-Staff meetings is attached hereto as Appendix "A".

Pursuant to the Notice, the Hearings Officer received one petition for leave to intervene in the adjudication from the New England Fuel Institute. ("NEFI"). The Company timely filed an Opposition to the NEFI Motion. Oral argument was heard on the Motion at the pre-hearing conference on August 31st. After both parties had the opportunity to be heard, a Decision and Order was issued on September 8th, 1982, allowing NEFI to participate in the adjudication as a "participating person"

1 7 DOMSC, 1, 79 (1982).

under the provisions of 980 CMR part 1.05(3). NEFI's petition to intervene was otherwise denied without prejudice. Pursuant to that order, NEFI was invited to participate in the discovery process in the subject matter area in which it had expressed interest. NEFI did not submit any discovery and has not participated in any way in the adjudicatory process. The text of the Decision and Order is attached hereto as Appendix "B".

A second Notice of a public hearing on the proposed Spencer LPA facility was issued jointly with the Department of Public Utilities, which must adjudicate other aspects of the Company's proposal pursuant to MGL Ch. 164 s. 105A and Ch. 40A s. 3, on September 28th, 1982. A joint public hearing on the proposed facility was held at the Spencer Town Hall on the evening of October 21st, 1982.

During the course of the proceedings, the Company responded to four sets of document and information requests made by the Council staff. The record was closed on Tuesday, November 9th, 1982 and, in that no hearing was requested by any party, none was held. However, Boston Gas reserves the right to present further evidence to the Council in the form of sworn testimony if it feels such evidence is necessary after having had the opportunity to view the Tentative Decision.

IV. Forecast of Sendout Requirements

A. Introduction

Forecast review is an on-going process, as is forecasting itself, and individual forecasts can be understood best within the context of that process. This principle is especially applicable to the Boston Gas Company's forecast process, as the Company has submitted markedly different sendout forecasts in its last three filings with the Council. Thus, we will begin this analysis with brief descriptions of previously-submitted forecasts and their implications in order to view the present filing in the proper perspective.

1. Background

Traditionally, gas companies have used a "supply-constrained approach" in their sendout forecasts. Simply stated, the companies assumed that all of the gas they bought could be sold, and that the major limitations on sales were the supplies of gas available to each company. In this context, sendout forecasting was not a crucial part of the gas distribution business.

This situation has changed. Since 1973, the cost and availability of gas supplies have fluctuated dramatically.[2] At the same time, consumer usage patterns and the composition of sendout requirements by end use have changed as prices have increased.[3] Thus, sendout forecasts have become increasingly important as a way for gas companies to plan their supply purchases in a least cost fashion. Reliable sendout forecasts have also become more difficult to produce; the Companies need more understanding of market trends, more insight into consumer behavior, and more data than ever before.

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2 Gas Facts, American Gas Association, p. 27 and p. 121.

3 See Section B, infra., and Gas Facts, pp. 83-85.

2. The 1979 Forecast and Decision

Boston Gas made its first departure from traditional forecasting methods in 1979, when it used an econometric model to project firm demand as a function of the ratepayers' responsiveness to gas price, the prices of substitute fuels, regional macroeconomic conditions, and weather factors.

In its Decision on the 1979 filing,[4] the Council expressed its approval of the Company's progressive approach. The Council lauded the Company for its commitment to analyzing the components of customer sendout requirements, and for its willingness to collect data for the analysis. The econometric model itself, however, proved to be problematic. The Council questioned the theoretical basis for the model, the statistical insignificance of important coefficients and the integration of the model with the rest of the forecast. Generally, the Council concluded that more historical data and a deeper understanding of the structural relationships were needed to produce a reliable econometric forecast than were available to the Company at the time. These conclusion are reflected in the two Conditions on approval that addressed the reliability of the sendout forecast:

"3. That the Company document in its next Supplement how it projects the average use per residential heating customer is affected by forecasted conservation;

4. That the Company document in its next filing how its projection of the number of residential heating customer reflects forecast conservation."[5]

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4 4 DOMSC 50, 52 (1980).
5 Id.

The Company was urged to evaluate the appropriateness of alternatives to econometric modelling for predicting in a reliable fashion the magnitudes of and reasons for changes in customer usage patterns in its next filing.

3. The 1981 Forecast and Decision

Boston Gas did not use econometric modelling in its 1981 filing,[6] but reverted to more traditional methods of forecasting sendout. The Company forecasted load gain on the basis of historical sendout data normalized to correct for weather conditions, customer survey data, anticipated availability of pipeline gas and supplemental feedstocks, and local economic factors. Expected load gain was adjusted by assumptions for rates of load loss and conservation to produce the forecast of sendout.

In its Decision on the 1981 filing, the Council stated that the sendout forecast methodology was "inadequate in substance and documentation."[7] The Council Rejected "that portion of the Company's forecast which purports to satisfy Conditions 3 and 4 of our 1979 decision"[8] as unreviewable and questioned the reliability of the assumptions for rates of load loss and conservation. The Company was directed to improve the documentation of its sendout methodology in general, and its conservation and load loss assumptions in particular, in its next filing.[9]

6 7 DOMSC 1 (1982).
7 7 DOMSC 1, 77 (1892).
8 Id, p. 38.
9 Id, p. 77.

4. The 1982 Forecast of Sendout Requirements

The Company's 1982 filing is a substantial improvement over its previous submission to the Council. The methodology for producing the sendout forecast is documented particularly well. Boston Gas should be commended for submitting a thoroughly reviewable forecast of its sendout requirements. In addition, the Company staff deserves praise for its cooperation during the discovery process. Thus, the reviewability concerns which were an important issue during the 1981 forecast review have been alleviated during the 1982 proceedings.

The Company has also directly addressed the impact of forecasted conservation on the average use per residential heating customers. In Appendix "B" of the forecast, Boston Gas submitted a "Daily Sendout Analysis" of the variation in sendout per degree-day with the number of degree-days since 1974. The analysis, which is discussed in Sections B, C, and D infra, satisfies Condition 3 of the 1979 Decision with a thorough presentation of data and analysis of the results. The analysis also provides insights into the structural relationships inherent to sendout forecasting that were not available at the time of the 1979 filing.

Finally, the Company directly addresses the impact of forecasted conservation on the number of residential heating customers. This impact is addressed in the documentation of the sendout forecast methodology, which will be discussed in Sections C and D, infra. The documentation satisfies Condition 4 of the 1979 Decision.

5. Scope of the Analysis

We note here that the high standard of reviewability of the current submission allows us to address the appropriateness and reliability of the forecast in greater detail than was possible in earlier reviews. The Company has evidently put substantial effort into its forecast. The Council appreciates that effort, and hopes that the forthcoming analysis will be viewed as a constructive response to that effort, and as an important part of the on-going forecast review process.

The analysis has four parts. Section B presents the results of the Daily Sendout Analysis. Section C contains a detailed description of the sendout forecast methodology. Section D analyzes each section of the methodology, discusses the common themes, suggests improvements for future forecast and lays down the Conditions for acceptance of the next Boston Gas filing. The conclusions are summarized in Section E.

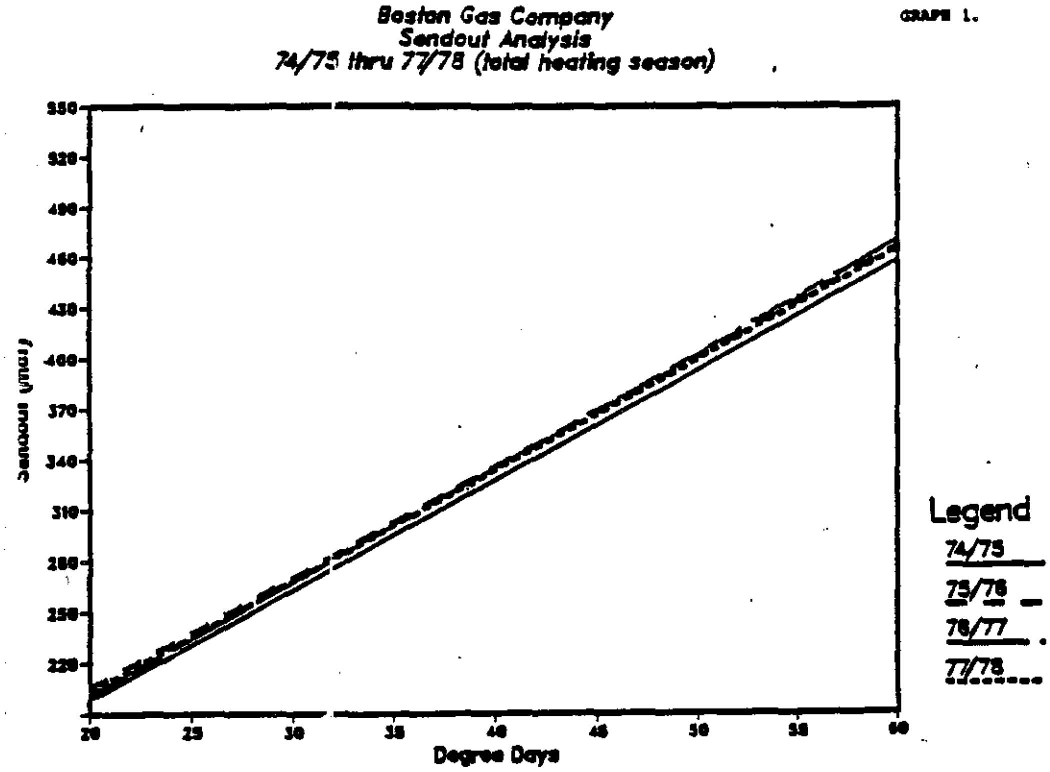
B. <u>The Daily Sendout Analysis</u>

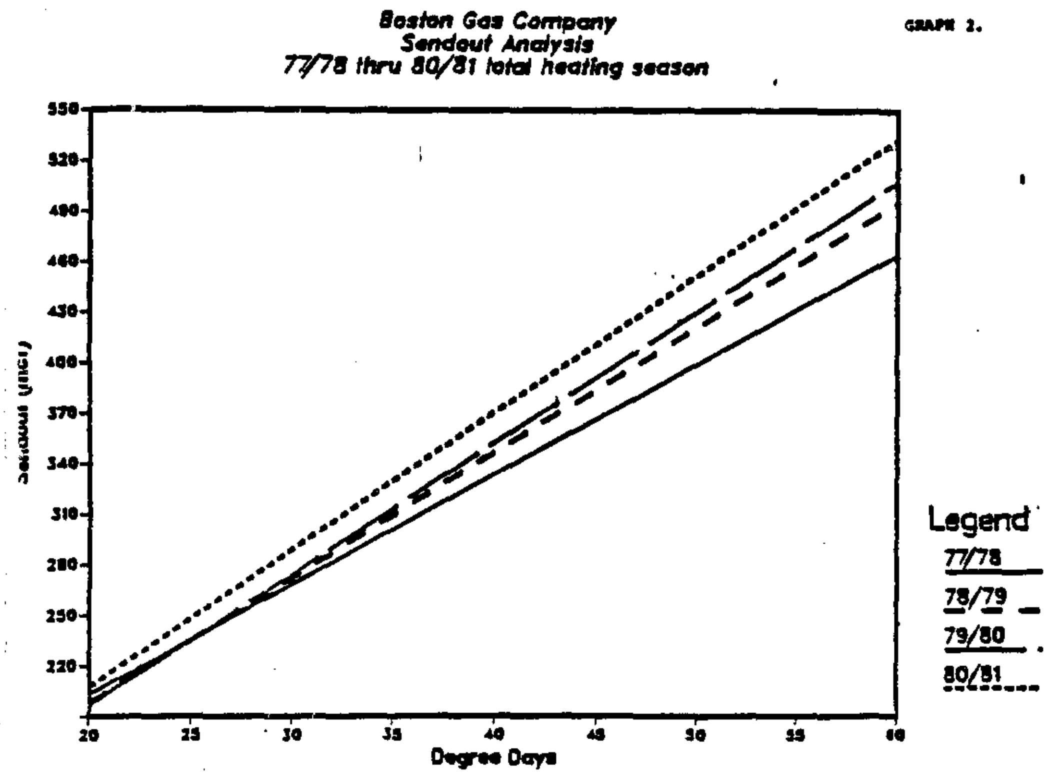
As Appendix B of the forecast, Boston Gas submitted a detailed analysis of the daily gas consumption patterns of its firm customers. The analysis examines the relationship between firm daily sendout and outside temperature as measured by degree-days. Using linear regression and moving average techniques, the relationship is analyzed for every year since 1974, for the heating and non-heating seasons, and for several specifications of the forms of the equation. The analysis also examines degree-day ranges of various widths and moving averages of various lengths.

The results are striking: sendout patterns have changed markedly since 1977. Figure 1 shows the two graphs of sendout vs. degree-days that are reproduced from the original analysis. As Graph I shows, the relationship appears to have stayed constant between the 1974-75 and 1977-78 heating seasons. In contrast, as Graph II shows, the relation-

Figure 1. Graphs of Sendout vs. Degree-days

GRAPHS I AND II





ship began to change in 1978. The daily sendout per degree-day, or the "heating increment" (the slope of the line), has increased in every year, and has become more sensitive to temperature. Since the 1977/78 winter, Boston Gas customers have begun to use more gas per degree day on cold days than on warm days. Moreover, the heating increment for a given temperature is different during the heating season and the non-heating season. There are many possible explanations for these trends, including:

- changes in customer behavior due to conservation, economic factors, or other unknown factors;
- changes in the mix of customer class and type;
- addition of new customers with usage patterns that differ from existing customers.[10]

These factors are difficult to quantify. However, they illustrate the general volatility of usage patterns over the last few years and the difficulties inherent to forecasting sendout in a reliable fashion. The implications of these changes in heating increments is discussed further in Section D, <u>infra</u>.

The sendout forecast uses the newly-specified relationship between sendout and degree days. The forecast defines a set of heating increments for ten degree-day intervals during the heating and non-heating seasons that are based on two-day moving averages of actual sendout data. Because the heating increments are different for each degree-day interval, this method can capture the changing sensitivity to temperature of the senodut requirements. It avoids the over-estimation of annual sendout requirements that results from the use of one heating

10 Forecast, Appendix B, p. 5.

increment for all degree day intervals. The method for forecasting heating increments is described in detail in Section C, infra., and analyzed in Section D, infra.

C. Description of Methodology

1. Determination of Annual Load Growth

Boston Gas begins its forecast with the assertion that "a net increase of one percent in annual firm load growth is a reasonable objective".[11] The one percent figure is used as a starting point for forecasting actual load growth. The Company acknowledges that gas deregulation and changing customer usage patterns may have a major impact on sendout requirements and future load additions. The one percent growth rate is justified as attainable with existing availability of supplies and facilities and without overreliance on LNG deliveries from DOMAC.

The Company makes several assumptions as to the nature of its load growth. The Company assumes that 90% of the new load will be temperature sensitive. Much of the new load will come from conversions of existing residential non-heating customers to gas heat. In addition, the Company plans to add exactly 100 new residential customers and 100 MMcf of new commercial industrial heating load per year through the forecast period.

2. Calculation of Heating Increments

The first step in the sendout forecast is calculation of the "heating increments," or, the forecast of sendout-per-degree-day for each degree day range. The heating increments are a direct outgrowth of

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11 Forecast, p. 17.

the Daily Sendout Analysis (see Section B, supra). Table D-1 shows the actual heating increments for the forecast period during the heating season. These heating increments use firm sendout for the Company as a whole; they do not distinguish sendout by customer class or sendout division.

The heating increments for the heating season are calculated in five steps. First, load growth is estimated as a 1% net increase in total firm sendout. The same estimate of load growth is used for every year except 1982-83, for which more accurate data are available. Next, 90% of the load growth is assumed to be temperature-sensitive. The new heating load is then allocated to each temperature range. This is done by assuming that future load growth will be distributed across degree-day ranges in the same way as load growth from 1980/81 - 1981/82. As shown on Table D-2, the change in heating increment for each degree day range is multiplied by the number of design year degree-days in that range to yield the total load added from 1980/81 to 1981/82. The percentage of load in each range is then computed by dividing the load added in each range by the total load. To calculate the change in heating increment within each range, the estimated new heating load is multiplied by the percentage of load in each range and divided by the number of degree-days within that range. Finally, the change in heating increment is added to the previous year's increment (the "base") to yield the new heating increments.

For the non-heating season, the Company uses the same heating increments through the forecast period that it observed during the 1980-81 split-year. Different sets of heating increments are used for the April-August and September-October periods in accordance with the

TABLE D-1

Boston Gas Company

Five-Year Forecast of Heating Increments by Degree Day Range

A. Heating Season

Heating Increments (MMcf/DD)

Degree Day Range	Base 1981-82	1982-83	1983-84	1984-85	1985-86	1986-87
0-10	6.98	6.98	6.98	6.98	6.98	6.98
10-20	6.98	7.12	7.32	7.52	7.72	7.92
20-30	7.44	7.49	7.56	7.64	7.71	7.78
30-40	7.52	7.56	7.62	7.68	7.73	7.79
40-50	7.84	8.08	8.43	8.77	9.12	9.46
50+	8.06	8.08	8.11	8.14	8.17	8.19

B. Non-Heating Season

April - August		September - October	
Degree Day Range	Heating Increment	Degree Day Range	Heating Increment
0-10	6.08	0-10	4.47
10-20	5.47	10-20	6.57
20+	7.16	20-30+	7.29

TABLE D-2

Boston Gas Company

Distribution of New Load by Degree Day Range

Degree Day Range	Change in Heating Increment 80-81 vs. 81-82	X	Design-Year Degree Days	=	Load Added	Percentage of Load Added in Each Year (%)
0-10	0		0		0	0
10-20	.14		264		37	8.39
20-30	.05		1,152		58	13.15
30-40	.04		1,676		67	15.19
40-50	.24		1,098		264	59.86
50+	.02		761		15	3.40
TOTAL LOAD					441 MMcf	100.0%

results of the Daily Use Factor study.

3. Use of Gas Supply/Demand Load Balancing Model

The Company determines its sendout requirements and what supplies will be utilized to meet that demand with the assistance of its gas supply/demand load balance' computer model.[12] The model, called "ABC GAS", uses a dynamic programming approach that simulates daily sendout requirements through a year of operation, dispatches pipeline gas and supplementals to meet demand, and refills storage as needed. The model is an extremely flexible analytical tool for evaluating long-range planning and short-term dispatching strategies.

The model is used in three stages, as shown schematically in Figure 2.

First, the Company prepares the input data for the model. The input data include the heating increments, a year's worth of weather data for design and normal years, dispatching constraints from gas supply contracts and facility capacity, and price information.

A "design year" is defined as the coldest year for which a company plans to meet its firm customer customers' requirements. The Company uses a design year consisting of 6300 degree days, based on a one-in-seventeen probability of occurrence. To simulate design operations, the Company distributes the 6300 degree days over the year to define the number of degree days on each day of a design year. These daily degree day totals are the actual input to the model. The Company includes 25 days of extreme cold (45 or more degree-days) in its design year (the equivalent of the Council's criteria for a so-called "cold snap"), and uses a peak day of 73 degree days.

12 Forecast, p. 19.

A "normal year" is defined as a year that is neither warmer nor colder than average. The Company uses a normal year consisting of 5758 degree days based on a fifty-one year average of degree day totals at Logan Airport in Boston. Again, the 5758 degree days are distributed over the year to define daily degree-day totals for input into the model. A normal year includes 14 days of extreme cold in its design year, and has a peak day of 65 degree days.

After the input data are prepared, the model simulates operations for a full design year. Firm sendout requirements are simulated by combining design year weather data with the heating increments: supplies are used to meet sendout requirements in a manner that minimizes costs and recognizes the Company contractual obligations. The output of the simulation is the forecast of firm design year sendout as presented in Table G-5 of the forecast. The simulation also yields a detailed description of weekly dispatching operations, (i.e., which gas supplies are sent out and which facilities are used at which time over the year), and a set of "rule curves" that "determine on a weekly basis the inventory levels that are required should the Company experience design weather for the remainder of a given operating season".[13]

One further output of the design year simulation is the forecast of peak day sendout. The model calculates peak sendout by multiplying the heating increment for the 50+ degree-day range (in Mcf per degree day) by the peak total of 73 degree-days and adding the total to the daily base load. The forecast of peak day sendout is shown in Table G-5 of the forecast.

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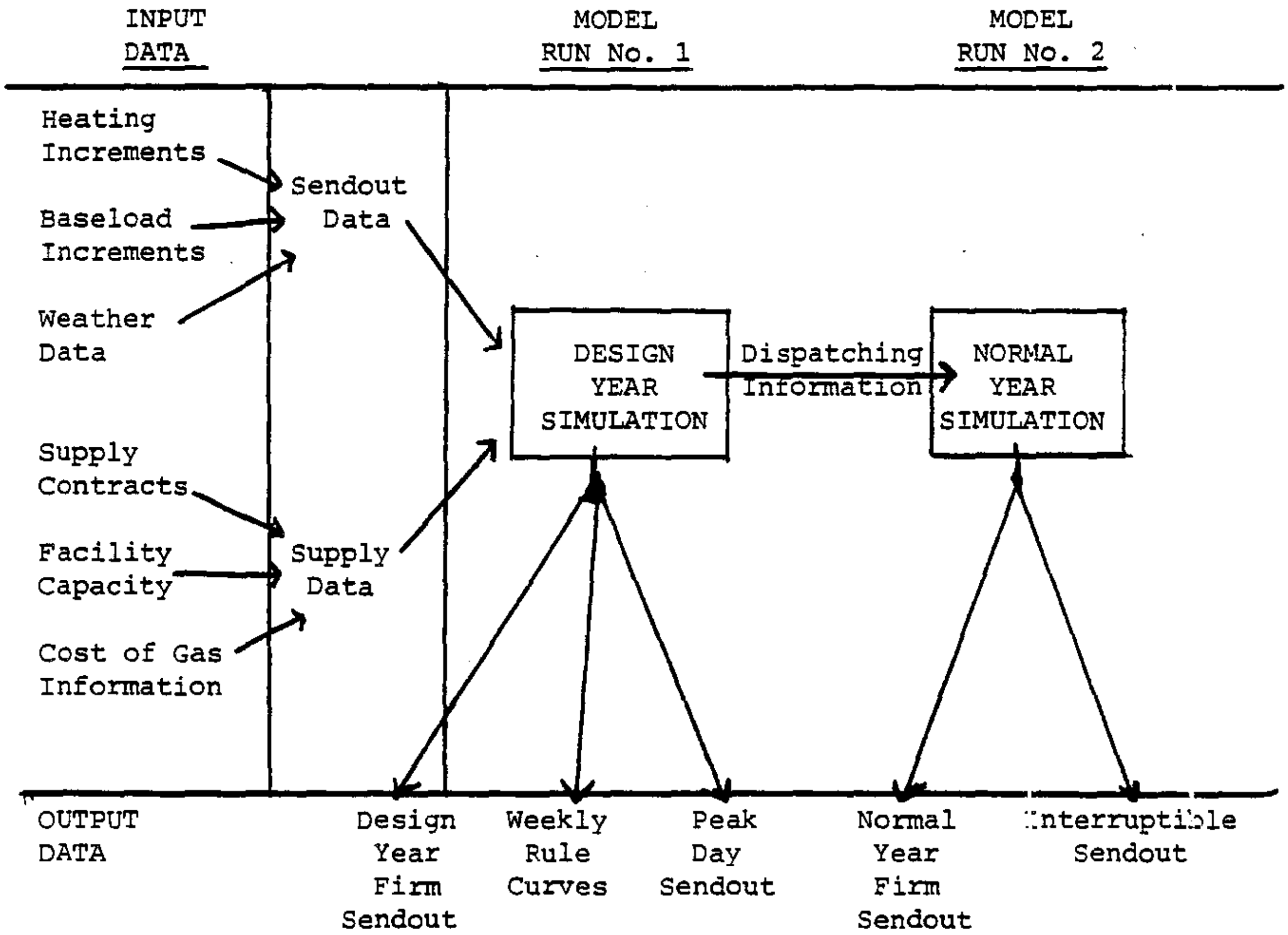
13 Forecast, p. 20.

FIGURE 2

Boston Gas Company

Schematic View of the Load Balance Model



The model then simulates operations for a normal year. Firm sendout requirements are simulated by combining normal year data with the heating increments. Supplies are dispatched in the same way as they were during the design year simulation. Clearly, in this simulation, more gas is dispatched than is required by firm customers. The excess gas is used to refill storage and to serve interruptible customers. The output of this simulation is the forecast of firm normal year sendout as shown in Table G-5, the forecast of interruptible sales as shown in Table G-4B, storage refill rates and cost information.

The input process and two simulations are repeated for each of the five years over the forecast period.

4. <u>Adjustment of Model Output</u>

After running the model, the Company determines how much gas is available for marketing to new customers. Initially, gross sendout is reduced by 6% to account for company use and losses. Next, the Company estimates the effects of conservation. Using the results of the Daily Sendout Analysis and reports generated by the Company's conservation data base, conservation by existing customers is projected to occur at the rate of 1 1/2% during the non-heating season. No conservation is projected during the heating season. The reduction in sales due to conservation in each year is added to that year's annual increase in total firm sales to yield the gross sales gain. Table D-3 presents the gross sales gain for the heating and non-heating seasons over the forecast period.

Next, the Company determines the weather sensitivity of the gross sales gains. First, the baseload for the 1982-83 heating and non-heating seasons is computed from the average monthly sendout during

TABLE D-3

Boston Gas Company

Forecasted Gross Sales Gain by Season
(MMcf at 1000 Btu)

Year	Gross Sales Gain, Non-Heating Season	Gross Sales Gain Heating Season	Gross Sales Gain Total
1982-3	344.7	406.8	751.5
1983-4	385.0	616.7	1001.7
1984-5	357.8	553.7	911.5
1985-6	359.3	563.1	922.4
1986-7	347.7	564.0	911.7

TABLE D-4

Boston Gas Company

Forecasted Gross Sales Gain by Temperature-Sensitivity
(MMcf at 1000 Btu)

Year	Gross Load Gain, Base Load	Gross Load Gain Temperature-Sensitive	Gross Load Gain Total
1982-3	354.9	396.6	751.5
1983-4	402.3	599.4	1001.7
1984-5	379.5	531.9	911.5
1985-6	386.9	535.5	922.4
1986-7	379.9	531.8	911.7

July, August and September. The ratio of base load to total load is computed for the non-heating season. The gross sales gain for 1982-83 is assumed to have the same ratio of base load to total load as was observed in 1981-82. By applying the ratio, the base load portion of the gross sales gain can be calculated. The remainder of the load is forecast to be temperature sensitive. The calculations are repeated for each year over the forecast period using the base load and the ratio of base load from the non-heating load of the previous year. Table D-4 presents base load and temperature-sensitive gross sales gain over the forecast period.

5. Allocation of Load Growth to Customer Classes

In the final step of its forecast, Boston Gas allocates the gross sales gain to commercial/industrial and residential heating customers for marketing. The intent is to determine exactly how many customers of each class can be added to the Boston Gas system without a need for additional supplies.

First, 100 MMcf of temperature-sensitive load is allocated for marketing to commercial/industrial customers. The remaining temperature-sensitive load is available for marketing to residential heating customers. Boston Gas assumes that the average new residential heating customer uses 110 Mcf annually for gas heat. Dividing the temperature-sensitive load by 110 Mcf yields the number of new residential heating customers to be added.

Next, the new residential heating customers are allocated by type. Exactly 100 new heating customers with no previous gas service are allowed annually throughout the forecast period; the Company also allows

Wakefield Gas Company, a total requirements customer of Boston Gas, to add 100 heating customers to its system each year.[14] The number of customers remaining is the number of current Boston Gas customers without gas heat that the Company can convert to gas heat in each year. These numbers appear in Tables G-1 and G-2 of the forecast as increases in the average number of customers.

The Company then forecasts how its residential marketing policy affects its availability of base load. The 100 new gas customers are assumed to consume gas for appliances and hot water at an average rate of 40 Mcf/year. Conversion customers and Wakefield customers are assumed to add an average base load consumption of 10 Mcf/year. These new residential base loads are subtracted from the total available base load to give the base load available for marketing to commercial/industrial customers. When added to the 100 MMcf of temperature-sensitive load allocated to commercial/industrial customers, the total gives the load, and allowable temperature sensitivity for new commercial/industrial customers. Finally, the number of new commercial/industrial customers is determined by dividing the new load for commercial/industrial customers by an average load of 690 Mcf per commercial/industrial customers. These numbers appear in Table G-3 of the forecast as an increase in the average number of customers.

Table D-5 presents the number of new customers in each class through the forecast period. Note that the Company will not add any residential non-heating customers: the apparent decrease in non-heating customers represents conversions to gas heat.

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14 See 8 DOMSC ___, EFSC 82-2.

TABLE D-5

Boston Gas Company

New Customers by Class

Year	Residential Heating	Residential Non-Heating	Wakefield Residential	Commercial/ Industrial
82-83	2598	(2498)	100	614
83-84	4440	(4340)	100	515
84-85	3826	(3726)	100	490
85-86	3859	(3759)	100	501
86-87	3825	(3725)	100	492

D. Analysis of Methodology

1. Structure of the Analysis of Methodology

For the sake of clarity, this section breaks down the complex Boston Gas sendout forecast methodology into four separate parts for analysis. The basic assumptions, the heating increment calculation, the sendout model and its adjustment, and the allocation of load for marketing are addressed individually. The analysis concludes with a summary of the common themes, and states suggestions and conditions for improvement of future forecasts.

2. Analysis of Basic Assumptions

The Company makes four basic assumptions in its forecast: namely, that sendout will grow by approximately one percent per year,[15] that 90% of the new load will be temperature sensitive;[16] that conservation will occur at a rate of 1 1/2% annually during the non-heating season, and that there will be no conservation during the heating season.[17]

a. Load Growth

The Council agrees with the Company that a net increase of one percent[18] in annual firm load is a reasonable objective. In a time of substantial uncertainty about future gas prices and customer usage patterns, a one percent growth rate is sufficiently modest to alleviate concerns about overestimates of the demand for gas. The one percent growth rate is significantly below last year's projection: as Figure 2

15 The 1% projection is based on: 1. it can be accomodated without posing increased risks to firm customers of curtailment due to a cessation of DOMAC deliveries; 2. the marketing strategy needed for this growth is consistent with projected load additions; and, 3. no major capital expenditures for distribution and production would be required to meet this forecast.

16 See discovery response EFSC 82-25, 34.

17 Forecast, p. 23.

18 Id.

Figure 3

Forecast of firm sendout, 1981 and 1982

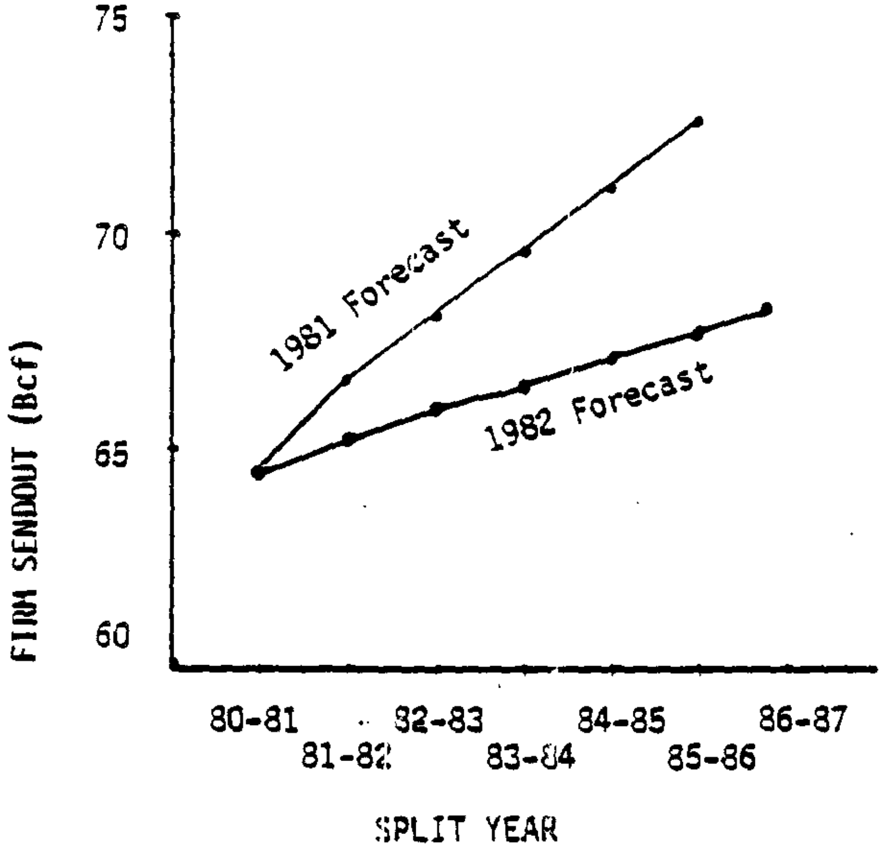

Table D-6

Boston Gas Company

Temperature-Sensitivity of New Load

Year	Gross Load Gain	Percent of Load Gain* that is Temperature-Sensitive
82-83	751.5	52.8%
83-84	1001.7	59.8%
84-85	911.5	58.4%
85-86	922.4	58.1%
86-87	911.7	58.3%

* Compare with Table D-4.

shows, the 1981 Forecast assumed a firm sendout growth rate of 12.5% over the forecast period as compared to 4.5% in the 1982 Forecast. Moreover, the Company explicitly acknowledges the possibility that growth may occur at lower rates than have been forecast.[19] The Company states in the Forecast that it has begun an analysis of the impact of two alternative load growth assumptions ("flat" load, with no load growth, and a net load loss of 1% per year) on its supply planning and marketing strategies.[20]

The Council is pleased with the Company's decision to analyze the sensitivity of its operations to its load growth assumption. An understanding of the impact of variations in basic assumptions is crucial to produce a reliable forecast of sendout, especially in times of great uncertainty. The Council would like to encourage further efforts of this sort, and requests the Company to provide this analysis when it becomes available.

b. <u>Temperature Sensitivity of Load Growth</u>

Before calculating the heating increments used in the forecast, Boston Gas assumes that 90% of the total load added will be temperature-sensitive. However, as Table D-6 shows, later calculations yielded estimates of gross load gain that ranged from 50-60% temperature-sensitive. Overall, the discrepancy is minor: a difference of 40% of load gain, which itself is only 1% of the total sendout, results in an error of less than 0.4% of the total sendout, a negligible variation. Nevertheless, the error may become significant if it affects the

19 *Id*, p. 24.
20 *Id*,p. 17.

estimate of how much of the new load occurs on peak days (see section 3, infra).

We note here that the new residential load is approximately 90% sensitive to temperature, as it consists mainly of conversions to gas heating. There is sufficient new industrial and commercial load, though, that the total new load is approximately 50-60% sensitive to temperature. We suggest that Boston Gas use a better estimate of the temperature-sensitivity of total new load when it calculates the heating increments in its next forecast.

c. Conservation and the Usage Patterns of Existing Customers

The Company assumes that conservation will occur at a rate of 1.5% per year during the non-heating season, and that there will be no conservation during the heating season. All "conserved" gas is marketed to firm customers (including conversions to gas heat). Table D-7, adapted from Table A-2 of the Forecast, shows that approximately 20-40% of all new residential heating customers are added because of "conserved" gas. The net effect of conservation by existing residential customers is to reduce the average gas use per customer. Table D-8, also adapted from Table A-2 of the Forecast, shows how the average use per residential customer declines over the forecast period due to conservation by existing customers. As Boston Gas explained during discovery,[21] this trend has two separate parts. Use per customer is declining for existing residential customers; however, because new gas customers tend to use more gas than existing gas customers (mainly because 60,000 of the current "heating customers" have only gas space heaters or stove heaters), the overall average use is declining at a

21 See discovery response, EFSC 82-25, 33B.

Table D-7

Boston Gas Company

New Residential Customers Due to Conservation

Split Year	(A) Load Addition due to Conservation	(B) Load for Marketing to Residential Users	(C) Percentage: (A/B)	(D) Number of New Customers	New Customers due to Conservation (CxD)
1982-83	146.1	372.2	0.393	2598	1020
1983-84	146.2	635.2	0.230	4400	1013
1984-85	147.1	546.9	0.269	3826	1029
1985-86	147.6	551.1	0.268	3859	1034
1986-87	148.1	545.0	0.271	3825	1039

Table D-8

Boston Gas Company

Conservation and Use per Residential Customer

Split Year	Use Per Customer: Load Additions	Use Per Customer: Existing Customers	Overall Average Use per Customer
1982-83	143.24	131.34	131.47
1983-84	144.36	130.86	131.08
1984-85	142.94	130.48	130.67
1985-86	142.81	130.08	130.27
1986-87	142.61	129.69	129.88

lower rate than the 1.5% estimate.

The Company places a "low level of confidence in these estimates... and believes them to be conservative."[22] To improve reliability of their forecast of conservation effects, the Company has several efforts underway to collect more data. Research proposals listed in the Forecast include meter-reading of a sample of residential customers, a new appliance saturation survey, and studies of non-price motivations for use of gas heat. The Company is also collecting marketing data on its customers, and is studying the possible responses of commercial and industrial customers to rising prices.

As in previous years, the Council lauds the Company's commitment to data collection for use in the sendout forecast. The Council agrees that the use of different conservation rates for the heating and non-heating seasons seems appropriate, and agrees that the results of the Daily Sendout Analysis support this forecasting technique.

Moreover, the Council finds that the previous conditions on forecast approval that address conservation, including Conditions 3 and 4 of the 1979 Decision and Condition 3 of the 1981 Decision, have been satisfied in the 1982 Forecast by the information provided in Tables D-7 and D-8.

Yet, the Council is concerned that these estimates of conservation may not, in fact, be conservative. The Council recognizes three potential sources for inaccuracy: the potential for bias in data bases, too much aggregation, and too much uniformity.

One major source of information for estimates of conservation rates is the Company's conservation data base. The Company began to monitor

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22 Forecast, p. 24.

the annual consumption patterns of 115,000 residential customers and 8200 commercial/industrial customers in 1979. According to the forecast,

> ... each customer's current consumption is compared bimonthly to prior year consumption on a weather-normalized basis. The computed percent charge from one year to the next indicates the level of annual incremental conservation the Company experiences from existing customers.[23]

Since 1979, the residential data base has been reduced to about 45,000 accounts, and the commercial/industrial data base to about 7000 accounts, because of turnover. The Council is concerned that selection of the least transient customers for monitoring will overestimate the amount of conservation actually taking place. There are many reasons why transient customers have less incentive to invest in conservation than permanent customers. If the conservation rate for permanent customers is taken as representative of all customers, the estimate may not be conservative. The Council cannot determine from the forecast how the Company accounts for this potential bias.

The Council questions the use of one set of conservation rates for all customer classes and sendout divisions. As the Company's own data bases must show, residential and commercial/industrial customers conserve energy at different rates for different reasons. Too much aggregation masks important differences in the explanation of how sendout requirements change for each customer class. For example, "load loss" in the commercial/industrial sector that is treated as due to conservation may actually be due to the recession: economic recovery could result in substantially higher sendout requirements for

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23 Forecast, p. 22, Note 9.

commercial/industrial customers even though the "conserved" gas has been marketed to new firm customers. Likewise, the sendout divisions may differ substantially in conservation rates because of variations in their composition of customers. Furthermore, even within customer classes, conservation rates vary widely among "subclasses"; e.g., tenants vs. landlords, apartment building vs. small commercial buildings vs. large industrial customers.

In a similar vein, the Council questions the use of the same conservation rate for every year over the forecast period. This assumes that the conservation rate does not depend on gas prices, the prices of alternative fuels, appliance saturation rates, economic conditions, or some proxy for personal income. Yet, a residential customer's ability to invest in conservation depends on income, an industrial customer's conservation efforts depend on price, and "load loss" rates depend heavily on the relative price of alternative fuels.

An important issue here is the definition of "conservation." Conservation can be installation of insulation, storm windows, etc., can be behavioral in nature, or it can be "load loss" due to the actual loss of customers to alternate fuels. Past Council decisions have stated the importance of identifying these components of "conservation". As the Council has stated previously: "the ability to forecast sendout accurately depends on forecasted conservation... Conservation is one outcome of a change in customer usage, so that the issue of conservation is a microcosm of the larger issue of customer usage... The key to forecasting conservation accurately is in forecasting usage."[24]

24 7 DOMSC 1, 34 (1982).

The present forecast does not distinguish between load loss and conservation in a clear and consistent fashion. The issue is pertinent both to the assumed conservation rates, and to the way heating increments are projected.[25] To produce a reliable forecast of sendout requirements, the Company must recognize the variety of causes for reductions in sendout requirements through a disaggregated treatment of the available data.[26] .

The Council understands that disaggregation requires significant expenditures of time and money for data collection and analysis. We note here, again, that the Company is already making substantial efforts in this area.

Nevertheless, the Company must make better use of the data it has to forecast conservation.[27] At a minimum, in its next forecast, the Company must state explicitly the conservation rates that it uses for different customer classes, divisions, or subclasses within customer classes. The Company must also show how conservation rates change over the forecast period, or, if the rates stay constant, justify why constant rates are forecast. Finally, the Company must state how it uses its data bases to prepare the forecast of conservation rates, and state how potential biases in the data are taken into account. Conditions 1, 2 and 3 infra, address these problems.

In addition, the Council requests that, in its next forecast, the Company provide an update of its data collection efforts, state which efforts have been successful, which efforts have failed or not been

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25 See IV.D.3.a., infra.
26 Id.
27 Id.

considered, and the reasons behind the decisions (similar to the information provided in the "Documentation of Forecast Methodology" section of the present filing).

3. Analysis of the Heating Increment Calculation

The use of heating increments that vary with the degree-day range, as recommended by the Daily Sendout Analysis, is a significant improvement in forecasting the sensitivity of sendout requirements to temperature. The new methodology distributes new load among days with various degree-day levels, and distinguishes between sendout patterns in the heating and non-heating seasons. Both features improve the reliability of the forecast. The Council recognizes these improvements, and appreciates the Company's extensive documentation of the heating increment calculations. The calculation process is a relatively new one, though, and has not yet been developed and refined. Thus, the analysis that follows is offered as a constructive attempt to improve the reliability of the variable heating increment approach for future forecasts of sendout.

The Council has two major concerns with the heating increment model as currently used: use of constant base increments over the forecast period, and the method of distribution of new load among degree-day ranges.

a. Use of constant base increments

The Council questions the use of heating increments from the 1981-82 heating season as a base that will remain constant through the

TABLE D-9

Boston Gas Company

Heating Increments from 1976-77 to 1981-82, Heating Season

Degree Day Range	1976-7	1977-8	1978-9	1979-80	1980-1	1981-2
10-20	6.84	7.22	6.64	6.23	6.84	6.98
20-30	6.86	7.05	7.00	6.77	7.39	7.44
30-40	6.86	6.82	7.05	7.16	7.48	7.52
40-50	6.81	6.76	7.04	7.16	7.60	7.84
50+	6.75	6.58	7.15	7.02	8.04	8.06

TABLE D-10

Boston Gas Company

Annual Changes in Heating Increments, 1976-77 to 1980-81-1981-82

Degree Day Range	76/76-77/78	77/78-78/79	78/79-79/80	79/80-80/81	80/81-81/82
10-20	.38	(.58)	(.41)	.61	.14
20-30	.19	(.05)	(.23)	.62	.05
30-40	(.04)	.23	.11	.32	.04
40-50	(.05)	.28	.12	.44	.24
50+	(.17)	.57	(.13)	1.02	.02

NOTE: Numbers in parenthesis are negative.

forecast period. Table D-9 shows heating increments for heating seasons for 1976-77 to 1981-82; Table D-10 shows the changes in the heating increments from year to year over the same period. The heating increments have been extremely volatile over this period. The variations have many possible causes: different amounts of load growth in each year, varying responses to weather conditions, conservation, economic cycles, changes in the mix of customers classes, variations in oil prices and income effects. The direction and size of each factor differs between different customer classes; it may also vary between sendout divisions.

The Council is concerned that the use of a single set of heating increments to represent the combined behavior of all existing firm customers over the forecast period may lead to substantial forecast inaccuracy. The Council recognizes the usefulness of a forecast of overall sendout. However, for the forecast to be reliable, the Company must understand customer usage patterns at least at the level of individual customer classes or sendout divisions. Too much aggregation obscures the dynamics of the marketplace and relies too heavily on the assumption that past trends will continue unchanged into the future.

In this case, the sendout requirements of those who were Boston Gas's customers in 1981-82 may be quite different in future years depending on a host of factors. The "base" heating increments are likely to change over the forecast period, and the changes must be modeled explicitly to determine the supplies of gas available for marketing.

The Council cannot mandate use of a specific methodology.[28] However, if Boston Gas elects to use a heating increment approach, the Council must insure that the approach is appropriate for a Company of its size. As the largest gas company in the Commonwealth, it is appropriate that Boston Gas have an significant understanding of how the sendout requirements of individual customer classes and sendout divisions are changing, and that this understanding be incorporated into its forecast.

We have already mentioned our concerns about modeling the changes in usage patterns by existing customers as "conservation." (see Section IV.D.2.c, supra). The heating increments approach provides the opportunity to model the same effects in a somewhat different fashion. One could model differences in customer usage between existing and new customers by projecting separate heating increments through the forecast period for each group. Alternatively, heating increments could be disaggregated by sendout division, customer class, or both; and then re-aggregated for use in the model.

Again, the Council recognizes the cost of data collection, and the inaccuracies associated with using data from the past to forecast sendout. Nevertheless, the Company must take the important step of using the data it has to forecast how the sendout requirements of its customers will change. The Company already keeps track of the heating increments and daily sendout base loads for each of its sendout divisions. Furthermore, the ABCGAS computer model that Boston Gas uses

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28 M.G.L. c. 164, sec. 69J.

to simulate its sendout requirements has provisions for forecasting by sendout division and by customer class. These resources should be more fully utilized to improve reliability in the future.

Thus, the Company is directed that, in its next submission to the Council, it forecast the sendout requirements of its existing customers by adjusting the base heating increments to reflect its knowledge of changing usage patterns in its customer classes and divisions, and that these adjustments be documented in the forecast. Condition No.4 to this decision addresses this issue.

b. Distribution of new load among degree day ranges

The Council is equally concerned with the way new load is distributed among degree day ranges on the basis of load additions from 1980-81 to 1981-82. As Table D-10 shows, the distribution of new load among ranges varies greatly from year to year. Table D-11 compares the average distribution of load growth between degree-day ranges over a six-year period with the distribution used in the forecast (based on one year). The long-term average distribution differs significantly from the forecast distribution in the upper degree-day ranges; where the forecast distribution shows disproportionate load growth in the 40-50 degree day range, the long-term distribution spreads growth evenly between the 30-40, 40-50 and 50+ ranges.

There are several explanations for the differences. The 1980-81 heating season was extremely unusual in that degree-days were abnormally distributed over the year. Sendout data for 1980-81 are complicated by the events of the "gas crisis" of January 1981; load growth data are unusual because of the temporary moratorium placed on conversions to gas

TABLE D-11

Boston Gas Company

Comparison of Long-term Load Distribution with the Forecast Distribution

	Long-Term Load Distribution				
Degree Day Range	Change in Heating Increment 76-77 vs. 81-82	X Degree Year Degree Days	= Load Added	Percent of Load Added in Each Range Long-Term Average	Percent of Load Added in Each Range Used in Forecast*
10-20	.14	264	37.0	0.94	8.39
20-30	.58	1152	668.2	16.96	13.15
30-40	.66	1676	1106.2	28.08	15.19
40-50	1.03	1098	1130.9	28.71	59.86
50+	1.31	761	996.9	25.31	3.40
			3939.2	100%	100%

* See Table D-2.

heat during that year. However, use of the long-term distribution is also problematic. The period from 1976-1982 was a time of major structural changes in gas sendout patterns, and load growth over this period might not be representative of future load growth patterns. A reliable method of distributing load growth over the degree day ranges would compare the composition of historical load growth with its distribution, adjust for income and price effects, and use the adjusted total to forecast sendout.

The most important use of the distribution is for the forecast of peak day sendout. The long-term distribution predicts a significantly larger increase in peak day sendout from load growth than the forecast distribution. Thus, use of different distributions yields different estimates of the need for peak shaving capacity. The differences are not critical for the major Boston Gas sendout divisions, where interconnections, back-up facilities, and gas stored for a design season give adequate leeway for forecasting uncertainties. However, in the smaller divisions that use propane-air gas for peak-shaving, underestimates of sendout at peak are of greater concern, especially if propane gas or trucks are not available on short notice.[29] The peak day sendout forecast must be reliable to insure that supplies are sufficient to meet needs in the small divisions.

Therefore, the Council directs the Company in its next forecast to improve its method of distributing new load over degree-day ranges.

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29 For example, in the Spencer division, the actual peak day sendout exceeded the contractually available pipeline capacity for the division on a day that was 16 DD's below the design peak (January 11, 1981). See Section V.D.1.b., infra., for a more complete discussion of the consequences of underestimates of peak sendout forecasts for small service divisions.

Specifically, the Company is required to examine the relationship between load growth in the 50+ degree day range, and the composition of load growth, to use the analysis in its distribution of load growth across degree-day ranges, and to fully document its assumptions. Condition No. 5 of this Decision addresses this problem, the Company is further required to forecast the daily sendout peaks of each of its sendout divisions in its next forecast. Condition No. 6 of this Decision addresses this problem.

4 Analysis of Use of the Supply/Demand Model

An analytical model is only as reliable as the data and algorithms that compose it. We have discussed the heating increments in Section IV.D.3., supra: now we address the use of dynamic programming and simulation techniques to produce a sendout forecast.

"Dynamic programming" is an optimization technique that is used to determine the best path through a set of sequential decisions. Essentially, one determines the desirable outcome of those decisions, and then runs backwards through the process to optimize the objective at each step of the process.

In the case of a sendout forecast, the dynamic programming algorithm starts by determining the inventory levels and the remaining contract quantities for each of the Company's sources of gas at the end of the heating season. Using assumptions for daily sendout requirements, the model dispatches gas to meet requirements backwards from the end of the heating season to the beginning while minimizing cost at each step. The output is a set of "rule curves" and a set of dispatching instructions that tell the Company how much gas must be kept in inventory to meet design needs for the rest of the heating season.

The Council applauds this progressive approach to forecasting annual sendout for design and normal years, and for interruptible customers. By using dynamic programming, the Company meets its sendout needs and minimizes its costs in a systematic and reproducible fashion. Moreover, the rule curves provide a solid basis for making decisions on when to sell gas to interruptible customers.

However, forecasting involves a considerable degree of uncertainty. Experience with implementation of operations research models warns about over-reliance on dynamic programming techniques when forecasts may be uncertain.[30] The Council is concerned about one particular low-probability event; namely, the chance that a design year will occur and that the degree-days will be distributed over the heating season in a way that differs substantially from what the model assumes. If design weather occurs later than predicted, and inventory levels are not carefully monitored and maintained consistent with outputs from the load-balancing model, levels may be lower than desired; if design weather occurs earlier than predicted (as happened during the 1980-81 heating season), the Company may be overly reliant on timely acquisition of supplemental supplies. Both situations can be managed with constant monitoring of inventory levels.[31]

5. Analysis of Load Allocation for Marketing

In part IV.D.2.a. supra, we discussed the Company's objective of adding one percent net annual firm load, and determined that objective

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30 Majone, G., and E.S. Quade (eds), Pitfalls of Analysis, New York: John Wiley and Sons, 1980, Chapter 6. See also Huysmans, Jan H., The Implementation of Operations Research, New York: John wiley and Sons, 1970, Chapter 2.3; Beckman, M.S., Dynamic Programming of Economic Decisions, New York, Springer Verlag, Inc., 1978, Chapter 18.

31 See also, Section V.3, infra.

to be reasonable. However, the ability of the Company to sell those additional volumes and its decisions as to where in its eight divisions to sell those volumes are dependent on its marketing policy. The Company has provided the Council with a detailed description of its marketing policy[32] in this year's filing.

Boston Gas describes the current market as presenting a backlog of orders for gas service in both the residential and commercial/industrial sectors. This backlog is attributed to the existing price advantage gas currently enjoys over other competitive fuels and, the age of existing customers non-gas appliances. In response to this the Company has imposed a "controlled marketing policy" on new gas heating loads. The Company periodically projects available supplies and determines how much heating load can be prudently added. Once load is added up to available supply, the Company's "moratorium" on new hook-ups is re-imposed until new supplies are available.

The Company's assumption that additional volumes of gas will be marketable is based on: the assumption that gas will continue to have a competitive advantage over oil; surveys of industrial/commercial customers which indicate that few, if any of this class of customer is likely to convert;[33] the existence of a demand for process gas; and, a demand for gas service in sectors wherein fuel substitution is not available (i.e., glass manufacturing, restaurants). The Company contends that future load addition will likely be "price-sensitive", it has also identified a segment of the residential market which expresses a preference for gas regardless of price. The Company is currently consi-

32 Forecast, pp. 27-37.

33 We note that the desire for new gas service and conversions was strongly voiced at the Spencer public hearing. See: part V.4.1, infra.

dering research designed to better understand that market. This is encouraging in light of of the decontrol of natural gas prices and the attendant rise in gas costs to consumers. On the basis of its submissions and plans for research, we consider the Company's marketing objectives to be reasonable, though they are inherently subject to uncertainty. They are, however the product of a process which meets our statutory guidelines.

The Council has one concern regarding the way in which load is allocated between customer classes: namely, the composition of the commercial/industrial class.

Boston Gas forecasts the combined sendout requirements of its commercial and industrial customers. There is a good reason for this: the Company does not distinguish between commercial and industrial classes in its rate classifications,[34] and does not keep disaggregated data on these classes as they correspond to Table G-3A and G-3B which the Council requires in forecast submissions.

Nevertheless, commercial and industrial customers have different usage patterns, react differently to price signals, and have differing amounts of dual fuel capacity. A reliable forecast should distinguish between these customer classes in both forecasts of sendout and allocating load for marketing.

The Company recognizes the problem, and is in the process of SIC coding its commercial and industrial accounts.[35] According to the forecast, this process is 70% completed.

Disaggregated data on commercial and industrial customers should be incorporated into the forecasting process as soon as it is available. The company is directed to submit Table G-3A and Table G-3B, or their

34 See DPU 1100 (1982).
35 Forecast, p. 34.

equivalent, in its next forecast. If the SIC coding is not completed, the Company should state the status of the coding at that time.

E. Summary of the Analysis

Boston Gas has submitted a thoroughly reviewable forecast of sendout requirements and has made substantial progress toward improving the reliability of its forecast. The Council appreciates the Company's effort, and hopes that future forecasts reflect a similar effort toward the goal of forecast reliability.

The Company has been Ordered to comply with seven Conditions in its next Supplement which relate to its forecast of sendout. These have been discussed, in turn, in this section and are affixed hereto in Section VI, Decision and Order, as Conditions Numbers 1-7.

V. SUPPLY PLAN

A. COMPARISON OF RESOURCES TO FORECAST NEEDS

1. Resources Available for Normal Firm Sendout

a. Pipeline

Boston Gas has contracts with both the Tennessee Gas Pipeline Company ("TGP") and the Algonquin Gas Transmission Company ("AGT") for pipeline deliveries of natural gas. These contracts vary in two ways: some provide for annual and some for seasonal (winter) deliveries; and, the two pipelines serve distinct divisions within the Boston Gas system. Each pipeline system will be discussed separately.

1. Tennessee Gas Pipeline Company

The TGP pipeline serves all but one of the Boston Gas divisions (Boston/Norwood) and provides transportation for approximately 38% of the pipeline gas under contract to the Company. TGP provides gas under its CD-6 rate schedule on a firm annual basis up to the Maximum Daily Quantity ("MDQ") of 96.0 MMcf. TGP also provides gas on an annual basis of up to an Annual Volumetric Limitation ("AVL") of 24,304 MMcf. This AVL was imposed on TGP by the Federal Energy Regulatory Commission after the 1973 national gas shortage experience. TGP's actual Annual Contract Quantities ("ACQ") with Boston Gas is 35,032 MMcf. In addition, TGP provides for the transportation of 1,778.7 MMcf of winter storage gas on a best efforts basis.

The TGP pipeline enters Massachusetts at the New York and Connecticut borders and travels eastward through Worcester County, serving the Leominster, Spencer and Southbridge divisions of Boston Gas. The line then splits and tracks through the Mystic River valley, swinging northward to the New Hampshire border, providing gas to the Mystic/Lynn, North Shore and

Gloucester divisions. (See: Table 3, supra). Although TGP does not formally provide gas to the large Boston/Norwood division, that division is sufficiently interconnected with the Mystic/Lynn division so that gas delivered at two of that divisions seven take stations is a resource which must be considered when forecasting sendout in either division.[36]

2. The Algonquin Gas Transmission Company

The Algonquin pipeline serves only the Boston/Norwood division and provides transportation for 61.9% of the pipeline gas under contract to Boston Gas. AGT is a wholely owned subsidiary of Algonquin Energy, Inc. Eastern Gas and Fuel, in turn owns 36.8% of the Algonquin Energy's outstanding stock.[37]

AGT delivers gas on a firm basis under four rate tarriffs. Under the F-1 rate, AGT delivers an ACQ of 34,308 MMcf up to a firm MDQ of 127.1 MMcf for 270 days, and under the WS-1 rate provides additional pipeline gas at an ACQ of 2,894 MMcf up to a firm MDQ of 48.2 MMcf during 151 days of the heating season. Another wholly owned subsidiary of Algonquin Energy is Algonquin SNG, Inc., which produces pipeline grade synthetic natural gas from a naptha feedstock. Algonquin SNG sells this gas to its sister corporation, AGT for resale to Boston under the SNG-1 rate tariff at an ACQ of 1844 MMcf up to a firm MDQ of 12.2 MMcf. Lastly, AGT provides for firm return of winter storage gas under its STB-1 rate for 3500 MMcf at a firm MDQ of 29.7 MMcf for the heating season, and, for this winter only, return of 10.6 MMcf/day of 638 MMcf of storage gas from Consolidated under a best efforts contract which is

36 See Table S-7. We note that any "flexibility" in use of pipeline gas discussed is subject to approval of such use by the pipeline company and the FERC.

37 SEC Form 10-K of Eastern Gas and Fuel Associates.

Table S-1

Boston Gas Company

AGREEMENTS FOR PIPELINE GAS

Contract	Term of Agreement	Contract Period Volumes (MMcf)	Annual Volumetric Limitation (MMcf)	Maximum Daily Quantity (MMcf)	Number of Days Available
AGT F-1	Sept. 1st - Aug. 31st	34,308	N/A	127.1	365
AGT WS-1	Nov. 16th - April 15th	2,894	N/A	48.2	151[1]
AGT SNG-1	Oct. 15th - April 15th	1,844	N/A	12.2	180[1]
TGP CD-6	Nov. 1 - Oct. 31st	35,032	24,308	96.0	365[1]

1 add one day 1982-83 and 1986-87 due to the leap year.

Table S-2

Boston Gas Company

UNDERGROUND STORAGE AGREEMENTS

Contract	Transportation	Annual Storage Quantity (MMcf)	Term of Contract	Firm Maximum Withdrawal (MMcf)	Number of Days Available
Algonquin STF	AGT/STB-1 (firm)	3,500	Oct. 31st- April 1st	29.75	214
Consolodated	AGT (Best Efforts)[1]	638	Nov. 1, 1982- March 31,1983	10.6	
Honeoye	TGP (Best Efforts)[1]	800	Oct.-April	7.3	214
Consolodated	TGP (Best Efforts)[1]	102.7	Oct.-April	0.9	214
Penn York	TGP (Best Efforts)[1]	876.0	Oct.-April	7.4	214

1 This gas will be delivered by on a firm basis provided Boston Gas does not exceed it total firm MDQ on the respective pipeline.

firm up to system MDQ.

The contract under the SNG-1 rate differs from the others, however. Under that rate, Boston Gas has the right prior to the commencement of each heating season to reduce its firm take-or-pay portion up to 50% of the volumes originally contracted for. The Company has requested reduced nominated quantities of SNG-1 gas to be delivered during the 1982-83 heating season to an ACQ of 651 MMcf[38] (35.3% of contract) and expects to take 922 MMcf (50% of contract) in each remaining year of the forecast period. The volumes of SNG available to the Company for the 1982-1983 heating season may be taken according to the following schedule:[39]

	MDQ (MMcf)	Monthly Quantity (MMcf)
November, 1982	6.080	182.4
December 1-15, 1982	5.587	83.9
December 16-31, 1982	0	
January 1-31, 1983	12.210	378.6
February 1-15, 1983	0	
February 16-28, 1983	2.209	28.8
March 1-15, 1983	4.454	157.3
March 16-31, 1983	5.570	

b. LNG Supplies - Distrigas of Massachusetts Corporation ("DOMAC")

Boston Gas has contracts with DOMAC pursuant to which the Company receives on a take-or-pay basis an annual quantity of 13,746 MMbtu of LNG. These volumes of LNG are imported by the Distrigas Corporation, an affiliate of DOMAC, under an agreement between Distrigas and Sonatrach,

38 The Company informed the Council of this quantity pursuant to EFSC A.B. 82-1 and thus have satisfied condition number 8 of the last Decision and Order. 7 DOMSC 1, 79 (1982).

39 Forecast, p. 7, note 4.

S.A., the Algerian national oil and gas Company. Boston has a firm storage agreement with DOMAC pursuant to which Boston leases 643 MMcf of storage at DOMAC"s Everett facility. In addition Boston has a firm vaporization agreement with DOMAC for 66.6 MMcf/day which is injected into the pipeline at Everett, near the TGT and Mystic/Lynn - Boston/-Norwood interconnection.

Under its contract, Boston must remove one-half of its share of a Sonatrach LNG tank vessel shipment within 10 days of DOMAC's tender of that shipment, usually the day after unloading. The remaining half (not including the 643 MMcf firm storage) must be removed within 24 hours of the scheduled arrival of the next Sonatrach delivery. Boston is not obligated, to reduce its 643 MMcf at any time, except on a best efforts basis in the event DOMAC's available storage would be exceeded by a forthcoming Sonatrach tender.

As can be seen in Table S-3, Boston has 5183 MMcf of LNG storage available to it, 4140 MMcf of which is owned by the Company or leased from its wholly owned subsidiary, Mass. LNG. The additional 400 MMcf of storage is leased from Algonquin LNG at its Providence, R.I. facility. In addition to DOMAC supplies, Boston has the ability to liquefy pipeline gas at its Lynn and Dorchester Storage facilities at a rate of 7.35 MMcf/day and 6.00 MMcf/day respectively.

DOMAC supplies are normally removed from Everett by truck and stored at the Company's Lynn, Salem and Dorchester tanks, with the company policy dictating that these facilities be full at the outset of the heating season.[40] For the 1982-83 heating season, this will not be the case, however. We noted in our last two decisions concerning the

40 7 DOMSC 1 (1982), 8 DOMSC __, (1982), EFSC 82-25A (1982).

Table S-3

Boston Gas Company

SUPPLEMENTAL FUEL STORAGE AND SENDOUT CAPACITY

acility	Owned or Leased	Amount of Storage (MMcf)	Daily Sendout Capacity (MMcf)	Daily Back-up Sendout Capacity	Daily Liquefaction Capacity (MMcf)	Annual Contract Quantity (MMbtu)	Transportation of Fuel to facility
. LNG							
istrigas	Leased from DOMAC	643	66.6 (firm) 45.0 (best efforts)		N/A	13,746	Tank vessel
alem	Leased by Mass. LNG	1000	15	15	N/A	N/A	Truck
ynn	Leased by Mass. LNG	1000	125.0	62.5	7.35/day	N/A	Truck/pipelir
rovi-ence	Leased from Algonquin LNG	400					
orchester	Owned	2140	57.6	28.8	6.0/day	N/A	
eominster	Owned	none	2.4		N/A	N/A	Truck Hook-up
ebster	Owned	none	2.4		N/A	N/A	Truck Hook-up
pencer	Owned	none	0.5		N/A	N/A	Truck Hook-up
Total LNG		5183	259.8	106.3	13.35/day	13,746	
. LPG							
verett	Owned	65.6	40.0		N/A	N/A	Truck
. Concord	Owned	11.5	5.6		N/A	N/A	Truck
raintree	Owned	9.2	9.7		N/A	N/A	Truck
eominster	Owned	9.9	4.0		N/A	N/A	Truck
outhbridge	Owned	14.9	6.0		N/A	N/A	Truck/Rail
anvers	Owned	12.3	21.3		N/A	N/A	Truck/Rail
evere	Owned	14.9	6.1		N/A	N/A	Truck
loucester	Owned	9.7	3.9		N/A	N/A	Truck
eading	Owned	14.7	5.5		N/A	N/A	Truck
orwood	Owned	14.9	5.4		N/A	N/A	Truck
. SNG							
verett (LPG feedstock)	Owned	none	40.0		N/A	N/A	Truck
Total LPG		162.6	143.9				
. Gas							
loucester	Owned	0.3	0.1				

Company that the status of the Salem LNG facility would be uncertain at best for the 1982-83 heating season. At this point in time, the on-line date for the Salem tank remains uncertain and that, for the 1982-83 heating season only, the Company plans its supply on the basis of 3140 MMcf of Company LNG storage in addition to the 1043 MMcf of storage leased from DOMAC and Algonquin LNG.[40A]

c. Propane

The fourth major source of gas to the Company is liquefied propane gas ("LPG"). The Company presently operates ten liquid propane-air ("LPA") production facilities with a combined storage capacity of 162.6 MMcf. In addition, the Company maintains an SNG plant in Everett which, using LPG as a feedstock and can produce up to 40 MMcf/day of pipeline quality gas for injection. The primary sources for this gas are the terminal facilities at Newington, NH. (Dorchester, Sea-3) and Providence, R.I. (Petrolane). Boston has a contract with Dorchester Gas for the purchase of terminalizing of up to 50.0 million gallons per year at its Sea-3 facility. This terminalling agreement replaces the supplies of LPG which were formerly available to its through the Exxon terminal in Everett. This heating season will represent the first since Exxon Company, U.S.A. closed its terminal in Everett, and the second year during which the first during which the Company will have to supply its 40 MMcf/day Everett SNG plant and its 40 MMcf/day Everett LPA plant primarily by truck.[41]

40A During the course of the November 22nd Council meeting, the Company indicated that the Salem LNG tank would probably be returned to service in Mid-December, 1982, and be filled by truck.

41 The Company has received approval to rework its existing Everett LPG storage which will allow for more efficient truck unloading and a reduction in storage of 20,000 gal. to a new total of 840,000 gal. DPU No. 1144, (1982).

d. Canadian Pipeline Supplies

Boston Gas is presently participating in two joint ventures to deliver firm pipeline quantities of Canadian gas to its customers: Boundary Gas and Trans-Niagara. The Boundary Gas project consists of 14 participating utilities that have created the corporate entity Boundary Gas, Inc. This innovative approach to gas purchase and transportation has allowed the Companies to jointly negotiate with Canadian suppliers (in this case, Trans-Canada) for the purchase of pipeline volumes. TGP under a separate agreement with Boundary, will provide firm delivery of Boundary volumes. The Boston entitlement of Boundary is an MDQ of 14 MMcf up to an ACQ of 5,110 MMcf to beginning in the fall of 1984. The project has received preliminary approval of its import permit from the Economic Regulatory Administration,[42] hearings are scheduled to begin in December before F.E.R.C., for license to improve the TGP pipeline and the Canadian National Energy Board (the "NEB") which must approve Trans-Canada's export permit. We note that the on-line date for Boundary has slipped one year, from the fall of 1983 to the fall of 1984, since the Company's last decision.[43]

The Trans-Niagara project has undergone substantial changes since the Council's last review. At that time Algonquin and its partners[44] had anticipated deliveries from Pan-Alberta to be imported at Calais, ME., and to be transported by the proposed New England States Pipeline to Algonquin's existing pipeline system in Burrislville, R.I. However, Pan- Alberta recently withdrew its Calais export application before the NEB and filed an alternate application to export the volumes through its

42 See: ERA Order Nos. 44-45 (1982), The U.S. State Dept. must also approve the project.

43 7 DOMSC, 1, 55-56 (1982).

44 NOVA, Transco, and Texas Eastern.

Table S-4

Boston Gas Company

PROJECTED CANADIAN PIPELINE SUPPLIES

Contract	Term of Contract	Transportation	Maximum Annual Volumes (MMcf)	Quantities (MMcf)	Number of Day Available
Trans-Canada Pipeline Co. to Boundary Gas Project	Annual September 1984-September 1994	TGP (Firm)	5,110[1]	14	365
Pan Alberta to Trans-Niagara Pipeline Co.	Annual September 1984-September 1994	Texas Eastern Transco Algonguin(firm)	5,132[1]	15	365

1. Both contract require Boston to take or pay for the gas up to an annual load factor of 75%.

Niagara Falls interconnection. Accordingly, The NESP partners formed a new partnership and filed new regulatory proposals to reflect the change and now propose to transmit the gas via the Transco pipeline to New York City and, via Texas Eastern, to the Algonquin pipeline. The longer delivery distance will increase fuel use losses for transportation. The precedent agreement reflects the same requirement of 75% take-or-pay. If approved, Boston will receive, under Algonquin's C-1 rate firm, deliveries of 5,132 MMcf ACQ up to an MDQ of 15 MMcf. Algonquin and Boston forecast this gas to be available for the 1984-85 heating season.

2. Resources Available for Peak Day

a. System Peak Day

Peak day sendout represents the maximum rate of firm delivery at adequate pressure on a daily basis. Thus the maximum rate is a combination of two factors: the availability of volumes of gas; and, the physical capacity of the Boston Gas system to produce and deliver these quantities. Table S-5 summarizes the Boston Gas Company's system wide ability to meet peak day requirements with available resources.

Because Boston Gas has, relative to other gas companies, a large temperature sensitive load,[45] the Company relies heavily on supplemental fuels to meet peak shaving requirements.[46] On a system wide basis, the Company forecasts that its pipeline supplies are sufficient for its to meet firm sendout for up to 33 degree days. That is to say, pipeline

45 See Table 2, supra.
46 See discussion 7 DOMSC, 1, 57 (1982).

Table S-5

Boston Gas Company

COMPARISON OF RESOURCES AND REQUIREMENTS: PEAK DAY SENDOUT
(MMcf/Day)

Existing Resources	Planned Usage Last Year	Actual Usage Last Year	1982-83	1986-87
Algonquin:				
F-1	127.1	127.1	127.1	127.1
ST-1	29.7	29.7	29.7	29.7
WS-1	48.2	27.8	48.2	48.2
SNG-1	17.2	17.1	12.2	12.2
Tennessee:				
CD-6	96.0	94.8	96.0	96.0
Storage	0	7.7	0	0
Propane	52.8	1.2	69.3	69.3
DOMAC LNG	66.6	97.7	66.6	66.6
LNG Storage	202.9	156.4	187.9	202.9
SNG Manufacture	40.0	33.4	40.0	40.0
Salem Vaporization	0	0	0	
Tennessee Firm Storage Return	0	0	0	0
Boundary Gas	0	0	0	14
Algonquin/TransNiagara Gas	0	0	0	15
TOTAL	660.8	592.9	677.0	720.0
Degree Days - Design	73	73	73	73
Degree Days - Actual		49		
Forecast Sendout		647.0	654.4	663.0

Sources: Tables DD, G-23, G-5; 7 DOMSC 1, 56 (1982), Table G-5, 1981 Forecast.

quantities are adequate to meet firm sendout requirements on any day during which the mean temperature is 32° or higher. The next increments of supply over the Company's MDQ are supplied with the use of supplemental fuels, some manufactured and other best efforts gas delivered by pipeline. As discussed above, these are LNG, LPG, SNG, winter storage and winter service gas. As indicated by Table S-5, the Company has sufficient resource and capacity available and to meet its design peak day. However, unlike many companies, Boston depends in large part on having sufficient LNG in storage to meet peak day requirement, as they would utilize 6.0% of capacity LNG storage volumes on the peak day during the 1982-83 heating season. (assuming Salem LNG is not on-line). Boundary Gas, Trans-Niagara, upgrading winter storage to a firm basis, and additional use of LPG will all contribute to a reduction in the use of LNG over the forecast period; however, for the remainder of the forecast period, LNG will represent 37.3% of forecasted peak day sendout, and 5.1% of maximum LNG storage capacity equivalent will be needed to meet peak day sendout.

b. Peak Day by Division

Boston Gas consists of eight service divisions, six of which are physically isolated from each other except for their common connections with the TGT pipeline. On peak days each of these divisions operates differently, utilizing supplemental fuels at different degree day levels to meet varying peaks.

The Boston Gas divisions, and their characteristics, size, city-gate MDQs, base and heating load increments and degree day level are summarized in table S-6. It is important to note that the

Table S-6

Boston Gas Company

DIVISION CHARACTERISTICS

Division	Cities and Towns Serviced	Total Customers	Distribution Pressure Levels (psig) Min.	Max.	City Gate Station MDQ (MMCF/Day)	Heating Base Load (MMCF/Day)	Increment (MMCF/DD)	DD Level	Physical Piping Interconnections
Boston/Norwood	Boston, Quincy, Milton Newton, Watertown, Brookline, Wellesley, Somerville Chelsea, Norwood, Shirley, Groton, Ayer, Harvard, Boxborough, Littleton, Acton, Carlisle, Concord, Bedford, Lincoln, Wayland, Waltham, Sudbury, Weston, Abington, Braintree, Cohasset, Hingham, Hull, Rockland, Weymouth, Whitman Total - 33	292,000	0.25	200.0	Milton - 64.3 Wellesley - 48.3 Weston - 3.5 Waltham - 36.3 Braintree - 34.6 Everett - 85.7 Norwood - 8.9	29.8	4.77	See Note A	1. Combination 16", 24" and 20" connecting Boston/Norwood and Mystic Lynn. 2. 6" connection at University Ave., Norwood, between Boston/Norwood and Commonwealth Gas Co. 3. 6" connection at River St., Cambridge, between Boston/Norwood and Commonwealth Gas Co. 4. 8" connection at Westford Rd., Littleton, between Boston/Norwood and Lowel Gas Company
Mystic/Lynn	Arlington, Burlington, Lexington, Malden, Melrose, Medford, Everett, Reading, Revere, Stoneham, Withrop, Winchester, Woburn, Belmont, Saugus, Marblehead, Lynn, Nahant, Swampscott, Lynnfield Total - 20	145,000	0.25	200.0	Arlington - 31.4 Burlington - 10.4 Lexington - 3.8 Reading - 4.6 Revere - 6.0 Lynn - 14.1 Lynnfield - 3.9	14.8	2.31	See Note A	1. Combination 16", 20" and 24" connecting Mystic/Lynn and Boston/Norwood.

Table S-6 (cont.)

Division	Cities and Towns Serviced	Total Customers	Distribution Pressure Levels (psig) Min.	Max.	City Gate Station MDQ (MMCF/Day)	Base Load (MMCF/Day)	Heating Increment (MMCF/DD)	DD Level	Physical Piping Interconnections
North Shore	Salem, Peabody, Beverly Danvers, Middleton Total - 5	29,417	0.27	100.0	Salem/Beverly - 15.3 West Peabody - 2.0	3.9	.46	30.0	Isolated
Gloucester	Gloucester, Rockport Total - 2	5,870	0.25	100.0	Gloucester - 4.859	0.6	.09	48.9	Isolated
Southbridge	Southbridge, Dudley, Webster Total - 3	6,923	0.25	56.0	Southbridge - 7.0	0.9	.09	70.0	Isolated
Spencer	Spencer, Leicester, E. Brookfield, Brookfield, N. Brookfield, W. Brook-field, Warren Total - 7	2,989	0.25	62.0	Spencer - 3.8	0.5	.05	63.0	Isolated
Leominster	Leominster, Lancaster (part), Lunenburg Total - 3	6,200	0.25	100.0	Leominster - 7.8	0.8	.12	53.3	1. 6" connection at Pratt Street Lunenburg, connecting Leominster with Fitchburg Gas
Clinton	Clinton, Lancaster(part) Total - 2	2,426	0.25	60.0	Clinton - 2.8	0.2	.04	65.0	1. 6" connection at W. Boylston Street, Clinton connecting Clinton with Commonwealth Gas.

NOTE A: The DD level at which peak shaving takes place for the Boston/Norwood and Mystic/Lynn divisions vary. This variation occurs partly because as the weather becomes colder, the Tennessee Gas Pipeline MDQ is used increasingly to meet the senodut requirements of the remaining six division. Consequently, the DD level at which peak shaving is required in the Boston/Norwood and Mystic/Lynn division decreases. An estimate of the DD level for all eight divisions is a 33 DD level or a mean daily temperature of 32°F.

Source: Responses to EFSC-2 Discovery Question. (All current Boston Gas supply contracts.)

Boston/Norwood and Mystic/Lynn divisions are substantially interconnected. These divisions represent approximately 89% of all Boston Gas customers and 89.2% of system peak load.

i. Boston/Norwood

The Boston/Norwood division is actually the pre-1973 Boston Gas Company. It has approximately 292,000 customers and is by far the largest division. The division is served by the AGT pipeline which has an overall MDQ of 217.3 MMcf including firm deliveries of pipeline gas under four different rate tarriffs. The division has seven regular and one alternate take stations. The sum of the MDQ's for these take stations is 281.600 MMcf, thus allowing the Company the flexibility to allocate pipeline gas sufficiently to balance pressure and to more efficiently utilize its supplemental fuels and remaining pipeline quantities. Table S-7 is an indication of such flexibility, comparing actual divisional peak sendouts with facilities available.

On peak day, January 4, 1981, the Company took 148.513 MMcf from AGT, passed 93.206 MMcf of AGT supplies through the Everett interconnection to Mystic/Lynn, and utilized 294.335 MMcf of vaporized LNG which was produced by operating the facilities at Commercial Point and Distrigas above design capacity. This quantity was sufficient to meet the divisions peak sendout requirement of 349.642 MMcf, while sending out 93.206 MMcf to Mystic-Lynn. Thus, even though divisional peak customer demand was about 350 MMcf, actual peak demand was 442.848 MMcf due to the assistance provided to Mystic-Lynn.

ii. Mystic/Lynn

The Mystic/Lynn division, along with the North Shore and Gloucester divisions were acquired by the Company from the new England Electric

Table S-7

Boston Gas Company

ACTUAL PEAK DAY SENDOUT COMAPRED WITH FORECASTED PEAK CAPACITY BY DIVISION

(MMcf/Day)

	1981[1] Peak Demand	Pipeline[5] (MDQ)	Inter-Connection	SNG	LNG	LPA	Other	Total Sendout
1. a. Boston/ Norwood		AGT-281.600 TGP-0	w/Mystic/Lynn, Commonwealth; Lowell	40.0	124.2	55.3	8.0[2]	502.735
b. Actual	349.642	148.513	93.206	0	294.335[3]	0	0	442.848
2. a. Mystic/ Lynn		AGT-0 TGP- 74.200	w/Boston/Norwood	N/A	63.5	11.6		141.904
b. Actual	160.995	29.455	(93.206)		34.519	3.815		67.789
Subtotal (Actual Sendout)	510.637	190.999	93.206		328.854	3.815		510.637
3. a. North Shore		TGP- 17.3		N/A	15	23.1		55.4
b. Actual	34.426	9.191			25.235	0		34.426
4. a. Gloucester		TGP- 4.895		N/A	N/A	3.9	0.1	8.895
b. Actual	6.271	4.456				1.815	0	6.271
5. a. Leominster		TGP- 7.8	w/Fitchburg Gas	N/A		4.0		11.8
b. Actual[4]	8.777	5.551				3.226		8.777
6. a. Spencer		TGP- 3.8		N/A				3.8
b. Actual[4]	4.073	4.073						4.073
7. a. Southbridge		TGP- 7.0		N/A	N/A	6.0		13.0
b. Actual[5]	6.238	4.044				2.194		6.238
8. a. Clinton		TGP- 2.8		N/A	N/A	N/A		2.8
b. Actual	2.706							2.706

1. Except as noted, all Division peaks coincide with System peak 572.1 MMCF on January 4, 19
2. River Street Interconnection with Commonwealth Gas.
3. Includes Distrigas vaporization and boil off.
4. Occurred on January 11, 1981.
5. occurred on January 12, 1981.
6. Listed MDQ is a total of take station contractual MDQ's, Actual contractual system MDQs f individual pipelines are less - See Table S-5, supra.:

	Take Station Total MDQ's	System MDQ
AGT	281.600	217.3
TGP	118.000	96.0

System in 1973. As Table S-7 indicates, the division has a total of 67.804 MMcf MDQ at seven city-gate take stations on the TGP pipeline. At Lynn, it maintains a 1000 MMcf LNG storage facility with a name-plate maximum daily sendout of 62.5 MMcf/day and liquefaction capacity of 7.35 MMcf/day. The remainder of the division's sendout capacity is made up of two LPA plants: in Revere, rated at 6.1 MMcf/day; and, in Reading, at 5.5 MMcf/day. (See Table S-4). The total peak day capacity of the division is 141.904 MMcf/day.

During the actual peak day on January 4th, 1981, the division demand was 160.995 MMcf. This demand was met by taking 93.206 MMcf from the Boston/Norwood interconnection, vaporizing 34.519 MMcf of LNG at Lynn and 3.815 MMcf of LPA, while using 29.455 MMcf of pipeline gas from TGT within the divisions take stations. The importance of the interconnection within these divisions is underscored here, as only through its use did the two large divisions have the ability to inject large amounts of supplementals into the system to relieve the demand for gas on the pipeline systems. The systems can be viewed as follows:

	Sendout Capacity (MMcf/Day)	Peak Demand (MMcf/Day)
Boston/Norwood	509.100	349.642
Mystic/Lynn	148.300	160.995
TOTAL	657.400	510.637

iii. North Shore Division

The North Shore Division serves 29,419 customers in the communities of Salem, Beverly, Danvers, Peabody, and Middleton and is physically isolated from the rest of Boston Gas' service territory except through the TGP pipeline. The division has a pipeline MDQ of 17.3 MMcf at two take stations; the 1,000 MMcf LNG storage facility with two 15 MMcf vaporizers rated at 15 MMcf/day at peak capacity located in Salem, and an LPA facility located in Danversport having a maximum daily sendout of 23.1 MMcf,[47] for a total capacity of 55.4 MMcf/day.

On its peak day, again January 4th, 1982, the North Shore division experienced a peak demand of 34.406 MMcf. Actual sendout for that day consisted of 9.191 MMcf of pipeline gas; 25.235 MMcf of LNG and no LPG.[48] Thus, when pressed into service, the back-up LNG vaporizer was able to increase peak LNG sendout by 66%. Since the tank is questionable for this season, the Council considered and approved Boston Gas' proposed improvements to its LPA plant in Danversport. Were the division to experience another 34.426 MMcf peak demand while the LNG facility was out of service, demand could be met with the 40.4 MMcf of capacity available from the TGP pipeline and the newly approved and completed improvements to the LPA facility.

iv. Gloucester

The Gloucester division serves 5,870 customers in the communities of Gloucester and Rockport. Its total available capacity is made up of 4.985 MMcf of TGP pipeline gas; 3.9 MMcf of LPA and 0.1 MMcf of pressure storage gas totaling 8.895 MMcf. During the division's peak day on January 4th, 1981, the division met peak demand of 6.271 MMcf with 4.456 MMcf of pipeline gas and 1.815 MMcf of LPA.

v. Leominster

The Leominster division serves 6,200 customers in the communities of Leominster, Lancaster and Lunenburg. It has an MDQ from its city-

47 See: EFSC 82-25A. (1982)

48 We note that in a proceeding subsequent to this peak day experience, Boston Gas sought and received Council approval to substantially increase LNG sendout capacity. id.

gate take station on the TGP pipeline of 7.2 MMcf and a LPA facility rated at 4.0 MMcf/Day. Leominster is interconnected with Fitchburg Gas by a 6" main in Lunenburg which has not been used for the past 10 years. On its peak day, January 11th, 1982, its total sendout of 8.777 was met through 5,551 MMcf taken from the TGP pipeline and 3.226 of MMcf of LPA. This ability to physically take more pipeline gas into a division by use of supplementals in another division (in this case, LNG in Mystic/Norwood and the North Shore) is illustrative of the inter-divisional flexibility of the Company's system.

vi. Clinton

Clinton is the smallest of the divisions, serving 2,426 customers in the communities of Clinton and Lancaster. It is served only by the TGP pipeline to an MDQ of 2.8 MMcf of 2.706 MMcf. Clinton division experienced its peak on January 4th, 1981 of 2.706 MMcf. Clinton is met its demand by using solely TGP gas at close to its take station MDQ, made available through the use of supplementals in the larger, coastal divisions.

vii. Spencer

The Spencer division serves 2,989 customers in the communities of Spencer, Leicester, Warren and the Brookfields. Its sole source of gas is the TGP and has a take station MDQ of 3.8 MMcf. The Spencer division experienced its peak sendout of 4.073 MMcf on January 11th, 1981, as did the Leominster division. As with Leominster, the Spencer division met peak demand by exceeding its MDQ with pipeline gas made available through the use of supplementals in the large coastal divisions. However, by so exceeding the design capacity of the TGP latteral, pressure at the Spencer take station was reduced from a normal 100 psig to 80 psig. We address this potential peak day and pressure problem in Section V. D., <u>infra</u>.

<u>viii. Southbridge</u>

The last division of Boston Gas to be addressed in the Southbridge division. This division is in southern Worcester County on the Connecticut border and serves 6,923 customers in the towns of Southbridge, Dudley and Webster. The division is connected to the TGP by latteral and has an MDQ of 7.2 MMcf and has an LPA plant rated at 6.0 MMcf/day for a total capacity of 13.2 MMcf/day. The January 12th, 1982, actual peak for the division was 6.154 MMcf and was met by 4.044 MMcf of pipeline supplies and 2.194 of LPA.

<u>c. Conclusions: Peak Day</u>

Boston Gas has both sufficient gas resources and sendout capacity to meet its system-wide design peak demand with a margin of almost 4% reserve. This reserve will grow to almost 9% when the Salem LNG facility is again on-line. Likewise, the Company should be able to meet design peak in all of its divisions with the possible exception of Spencer. The particular problems of the Spencer service territory and the company's proposed remedy are discussed in part V.D., <u>infra</u>.

3. Cold Snap Analysis

The Council has defined a, so called, "cold snap" as a number of days in succession during the heating season at or near design conditions. As was noted in part V.B.2. supra, the ability of the Boston Gas Company to meet design conditions over a period of time depends primarily on its ability to peak-shave with LNG in its larger coastal divisions: Boston/ Norwood, Mystic/Lynn and North Shore. On a peak day Boston Gas sends out about 6% of its LNG storage capacity equivalent, or about 255 MMcf/day. If the Salem LNG tank is on-line, the sendout increases about to 270 MMcf/day and the percentage of sendout to storage capacity drops to 5.2%.

Thus, the Mystic/Lynn and Boston/Norwood divisions can meet an extended period of weather at or near design provided that LNG inventories are adequate. As was discussed in part IV.C.4, supra, if the Company utilizes its load balancing model wisely and applies its "rule curves" to control short-term inventory to meet design conditions, the Company should be able to easily meet the cold snap criteria for its largest divisions. In the North Shore division, supplies are adequate even without the LNG plant; however, with that system down, the division relies on the LPA plant at Danversport exclusively for 50% of peak requirements. Boston Gas should work with all due diligence to bring the Salem facility back on-line and ensure that the appropriate reserve margin is ready for emergency use.

The Gloucester and Southbridge divisions have pipeline MDQs which exceed peak and Leominster has met peak in excess of MDQ with pipeline gas made available form the use of supplementals in the larger divisions. In addition, Leominster has substantial (25%) excess capacity over peak due to its LPA plant.

Lastly, only Spencer would be in danger of interruption during a cold snap. Sufficient pipeline supplies could be made available over the divisions MDQ and, given time, the LNG truck hook-up could be activated, giving sufficient sendout to meet peak. However, the problem of maintaining pressure during a sudden and prolonged temperature drop is quite real. Spencer has survived serious cold snaps in the past (specifically December, 1980, and January, 1981) without interruption; however, we feel, for the reasons discussed in part V.D., infra, more flexibility in this division is needed.

4. Design Year

The design year is calculated as described in part IV, supra, and allocates degree days over the heating season in order to best predict the need and timing for resources and sendout. In the particular case of the Boston Gas Company the design year sendout requirements of 70.971 Bcf are allocated 31.5% to the non-heating season and 68.5% to the heating season. Boston Gas also indicates that of total supplies taken during the non-heating season, approximately 10.5 Bcf are carried over as inventory to the heating season. We will, then, look first at the forecast design non-heating season to determine the availability of resources to meet design sendout and to build inventories, and, secondly, review design heating season to assess the adequacy and reliability of resources forecast to meet sendout requirements.

a. Non-Heating Season

The Company's design non-heating season forecast sendout ranges

Table S-8(A)

Boston Gas Company

DESIGN YEAR - NON-HEATING SEASON
(MMcf)

	1982				1986		
Supplies	Total	Interruptible Sales	End Inventory		Total	Interruptible Sales	End Inventory
AGT							
F-1	14,402	5,881			10,561	7,420	
STF-1	3,760	0	3,500		4,091		3,500
WS-1	244	0					
SNG-1	17	0					
TGT							
CD-6	9,568	5,320			11,234	6,812	
ST-1	1,884	(224)[1]	1,818		1,934		1,818
Propane	0	0					
Vaporized LNG	7,773	0			6,752		
LNG Storage	4,557	0	4,183		5,495		5,183
Consolidated				Boundary	2,243		
(1982 only)	716		716	Trans-Niagara	1,871		
R-1		1,570					
I-1		3,364					
Total	47,829	15,911	10,217		46,393	14,232	10,501
Design	22,223				22,334		

1. Injected to Honeoye storage cushion

Table S-8(B)

Boston Gas Company

DESIGN YEAR - HEATING SEASON
(MMcf)

	1982			1986/87		
Supplies	Total	Interruptible Sales	End Inventory	Total	Interruptible Sales	End Inventory
AGT						
F-1	18,795	1,272	0	18,809	1,455	
S-1	* 3,500		508	* 3,500		1,038
WS-1	2,894		480	2,894		400
SNG-1	831			922		
TGT						
CD-6	13,155	568		12,903	715	
ST-1	* 1,818		1,614	* 1,818		1,773
Propane	458			458		
Vaporizes LNG	2,776			3,013		
LNG storage	* 7,132		2,957	*7,895		3,701
SNG						
Consolidated	716					
Boundary				1,600		
Trans-Niagara				2,265		
TOTAL	51,706	1,840	5,559	55,833	2,170	6,912
DESIGN	47,958			50,603		

*. See Table S-8(A) for beginning inventory.

from 22.223 Bcf in 1982 to 22.334 Bcf in the last year of the forecast period and represent growth of less than 0.4 of 1 percent. As is summarized in Table S-8(A), resources available during this period exceed design firm sendout by well over 100%. Over the forecast period the Company utilizes 21-22% of total supply available to build inventories for the up-coming heating season and sells the remainder, if possible, to interruptible customers. It should be noted that gas made available to the Company by both pipelines under the R-1 (TGP) and I-1 (AGT) rates is on an interruptible basis. The Company takes these volumes only if they can re-sell them to their own customers. Such supplies are not factored into total supply available, firm sendout or design requirements.

It is important for Boston Gas to have non-heating season end inventories of 3,500 MMcf in S-1, 5,183 MMcf (4,183 in 1982-83 due to the outage of the Salem LNG tank) in LNG storage, and 1,818 MMcf in ST-1. These volumes, and large purchases of propane would allow the Company to meet firm design heating season load in the event of a cessation of LNG deliveries from Algeria.

<u>b. Heating Season</u>

In each of the heating seasons for the forecast period, Boston Gas maintains about a 10% reserve of supplies <u>over</u> design conditions. As was noted above, however, beginning inventories of S-1, ST-1, and LNG are key to the Company's ability to meet firm design needs without reliance on Distrigas LNG.

As an example, in 1982-83, Boston Gas forecasts to begin the heating season with 4,183 MMcf in LNG storage. From that storage, they forecast a normal sendout of 4,175 MMcf. In addition, Boston forecasts a direct sendout of 2776 MMcf from Distrigas. Were no Distrigas supplies arrive during the upcoming heating season, Boston Gas would have to replace 2768 MMcf of sendout. ((4,183)-(4,175)-(2,766) = -2768 MMcf). Boston Gas has a surplus of pipeline gas of 1,840 MMcf and could easily make up the remaining 928 MMcf through the use of its existing propane contracts with Dorchester Gas and Petrolane, if not through spot purchases, or, by taking optional quantities of SNG-1 volumes . If Boston Gas' peak propane sendout is maintained over the heating season's 214 days, the potential sendout could be 14,830 MMcf, far in excess of what would be needed to pick up a 928 MMcf short-fall and provide an adequate margin for design weather.

c. Conclusions: Design Year

Boston Gas has adequate resources to meet design year requirements provided that they manage those resources in an efficient manner. That is to say that the Company must ensure that, to the extent possible, LNG, ST-1 and S-1 storage inventories are at levels of 5,183 MMcf, 1.818 MMcf and 3,500 MMcf, or thereabouts, respectively at the outset of each heating season. This enables the Company to avoid placing itself too much at risk of a cessation of Algerian LNG and also avoid over-reliance on a single supplemental peak-shaving fuel: propane. Boston Gas forecast of resources available to meet sendout during design weather is more than adequate over the period of the forecast.

B. RELIABILITY, ADEQUACY AND COST OF HEATING SEASON SUPPLIES AND FACILITIES

"A true test of the Company's planning for meeting its projected firm sendout requirements is the overall quality of service during any given winter heating season".[49] The Company must demonstrate that, given committed resources and the changed conditions since those resources were committed, they have secured adequate and reliable gas sources at the least possible cost. M.G.L. c. 164, sec. 69I.

Table S-9 shows the Company's estimated cost of firm gas by source for the 1982-83 heating season.

Although it would appear from these figures that the Company should minimize dependency on the naptha based synthetic natural gas available under the AGT SNG-1 rate and propane, evaluation of the supply mix on a cost basis alone is deceptive. For instance, although the Company has a commodity cost of LPG at $6.71/Mcf, the market for LPG is soft and recent contract prices have ranged between $5.99-6.53/Mcf.* The Company has entered into a contract with Dorchester Gas in which the Company may either accept Dorchester's negotiated price for LPG, or go to the market itself. In any event, Dorchester Sea-3 must terminal the LPG at Portsmouth at a fixed charge to Boston Gas. As well, because of the world-wide availability of LPG, Boston Gas is not forced to enter into long-term contracts at high costs.

A second concern is the availability of Distrigas LNG.[49A]

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49 7 DOMSC 1, 61 (1981).

49A On October 12th, 1982, Boston Gas informed the Council in writing pursuant to EFSC AB 81-2, of a delay in the delivery of Algerian LNG. The problem, which remains uncorrected, is in the gas field pipeline gathering system. As a result, LNG will be shipped from both the ports of Arzew and Skikda, each with different Btu contents and specific gravities. This should pose no operational problems for Boston Gas. See: letters of Oct. 13th, 15th and Nov. 5th from Charles Buckley,Vice President, Boston Gas.

Table S-9

Boston Gas Company

ESTIMATED COST OF FIRM GAS BY SOURCE

	1982-83 ($/Mcf)[1]
1. Pipeline City Gate Purchase (Commodity Costs)	
a. AGT	
F-1	4.024
WS-1	5.035
SNG-1	11.442
STF-1	3.877
b. TGP	
CD-6	3.791
ST-1	3.949
2. Supplementals	
a. Propane	6.71[2]
b. LNG	5.9139[3]
3. Pipeline Demand and Fixed Charges/Month	
a. AGT	
F-1	$650,394[4]
STB	195,010[5]
SNG-1	440,550[6]
LNG	150,596
b. TGP	
CD	$679,538[7]
ST-1	145,503
c. Distrigas	80,375[7]

1. Compiled from EFSC-17 Discovery Responses; prices effective September, 1982.
2. Recent purchases of LPA through Dorchester Gas have been at a contract price of $6.71/Mcf FOB Newington.
3. We note that DOMAC is presently before the Economic Regulatory Administration and FERC over issues regarding price increases for LNG.
4. Includes Demand and Storage Capacity Changes covering April 1981-March 1981 plus Firm Storage Return Demand Charges which began in November, 1981.
5. Monthly Demand Charges apply only during the 5 month (Nov.-March) delivery season.
6. Charges began in August, 1982.
7. Excludes minimum bill requirements.

Problems have occurred in the past[50] and we Conditioned our last Decision and Order on the Company's commencing a formal study of the relative risks and costs of its supplemental fuels.[51] In Appendix "A" to its forecast the Company responds to this Condition (as guided by the staff pursuant to Condition No. 9 of that Decision, 7 DOMSC 1, 79) with a discussion of: 1. historical LNG deliveries; SNG and LPG supply markets; and, the potential long-run changes in the Company's usage of supplemental fuels.

According to the Company:

> "Because of the uncertainty and variability in deliveries exhibited by the Distrigas project, the Company has adopted the policy on planning on meeting its firm customers' winter needs in a design year without relying on this supply... In short, however, the Company plans to purchase propane, as necessary, to meet only deficiency resulting from such interruption."[52]

We feel that the Company has taken the prudent course in this area[53] by utilizing DOMAC supplies to meet inventory and current sendout requirements. We are however, concerned that this use of DOMAC LNG may become more difficult because of this alteration in delivery schedules.

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50 7 DOMSC 1, 66 (1982). Condition No. 1.

51 7 DOMSC 1,66,78.

52 Forecast, App. "A", p. 3.

53 Contingency planning is discussed more fully in Part V.C., <u>infra</u>.

The new Distrigas-Sonatrach agreement would alter the pattern of Distrigas deliveries so that a greater percentage of contract deliveries would arrive int he winter months.[54] Such a situation could cause problems for Boston Gas' supply planning.[55]

It is Boston Gas' policy, endorsed by this Council, to have LNG storage inventories at or near capacity levels at the start of the heating season. If DOMAC deliveries are curtailed during the summer months, Boston may have to curtail interruptible sales, and thereby generally increase Massachusetts' oil consumptions, and/or liquefy pipeline gas to fill LNG inventory. This would put the Company in the position of having to take-or-pay for significant volumes of DOMAC LNG (37% of 14 cargos) at a point in time whereas it's storage is full, forcing a choice by the Company of which supplies to take, and which to refuse and still pay for.

This dilemma could force the Company to empty storage during the heating season to make room for the increased flow from DOMAC LNG, and make the Company <u>more</u> dependent on Distrigas supplies to meet firm winter sendout.[56] The Council encourage the Company to achieve a speedy resolution of this issue in the best interests of its customers as pertains to the cost and reliability of gas.

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54 See: ERA Docket 82-13-LNG

55 See: Petition to Intervene and Protest of Boston Gas Company ERA Docket No. 82-13-LNG(1982).

56 Additionally, losing the ability to make interruptible sales through the use of summer LNG cargos could raise the price of gas to firm customers. (See part V.5, *infra*).

In its consideration of the relative risks and costs of supplementals, the Company has sought to increase its flexibility as to source of gas as well as the aforementioned flexibility in sendout. The Company has the ability to shift among its SNG-1 volumes, propane, DOMAC LNG, its own propane feedstock SNG and future Canadian supplies through both the AGT and TGP systems.[56A] The Dorchester Sea-3 contract, which allows for the terminalling of the equivalent of approximately 4,578 MMcf of LPG[57] permits Boston Gas the flexibility to back out 50% of its 1844 MMcf of SNG-1 gas as long as that gas remains expensive.[58] Likewise, the 7.979 MMcf of Canadian Gas from the Boundary and Trans-Niagara projects could be either marketed as firm gas or utilized to back out supplemental fuels, depending on the city-gate price of that gas.[59]

Lastly we note that the Company is pursuing discussion with TGP, in concert with other regional gas retail companies, in an effort to secure additional dedicated pipeline capacity. Such capacity could be well used to transport additional firm Canadian supplies or to firm up additional return of winter storage. This endeavor can add to the flexibility of the system and add to the diversity in supply mix which improves reliability. We expect the Company to keep us informed as negotiations progress.

We find that the Company's discussion of new Dorchester Sea-3 contract, its policy on the use of DOMAC LNG and SNG-1 gas, the firming up of the return of winter storage gas and its initiatives on Canadian supplies are satisfactory to meet the requirements of Condition No. 1 of

56A. Flexibility is limited by contractual obligations.

57 The exact amount will vary with btu content of the LPG.

58 Platt's Oilgram Price Report, No. 208, Vol. 60, p. 1-A; October 27, 1982.

59 See part V.D., infra.

our last Decision. The Company has followed policies set forth in that discussion in order to provide for a least cost gas mix, given the realities of sunk capital costs and existing contractual arrangements.[60] We commend them for this effort, and will continue to review their supply strategies to ensure that this remains the case.

C CONTINGENCY PLANNING

In our last Decision on the Company's supply plan, we ordered that the Company meet two conditions with respect to so called "contingency planning". These were:

> "5. That the Company assist the EFSC Staff in evaluating the trade offs between additional storage and the deliverability and security of supplemental resources, including propane, vaporized LNG and liquefied LNG;
>
> 6. That the Company further develop and substantiate its "contingency plans" to meet projected laod requirements in the event of a disruption of LNG supplies from Algeria, in view of the Council's determination herein."[61]

In its last submittal to the Council, the Company indicated that there would be no immediate impact of a cessation of DOMAC supplies occurring in November, as it would have a 45 Day supply of storage volumes to meet peak shaving needs. This assumes full LNG inventories. The Company's response in its last filing was that, during the 45 day grace period, they would.

1. Purchase additional liquid propane on the domestic and/or world markets;
2. Purchase LNG on the spot market;
3. Exchange oil for LNG with Japanese electric utilities;
4. Purchase emergency gas supplies from other, non-affected gas utilities; and
5. Appeal to customers for thermostat reductions.

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60 See: DPU 1100(1982).

61 7 DOMSC 1, 78-79(1982).

We expressed varying degrees of confidence in these procedures, but the main concern expressed, viz., "... the Company's admission that they do not have a specific at which they must begin liquefaction or institute their contingency plans..."[62], remains of primary importance in this area. The Company's response in the instant filing alleviates this concern considerably.

The main component to the Company's "contingency" planning is the overall gas supply planning which proceeds the heating season. As we have noted, the Company plans to meet firm sendout requirements without Distrigas volumes and reviews its actual weather experience, actual sendout and inventory levels regularly throughout the heating season.

At the outset, the Company plan requires that all LNG storage facilities available to the Company[63] be full or at sufficient levels prior to the beginning of the heating season. As we have noted in section V.A.3., supra, this inventory, coupled with other resources available to the Company, is sufficient to allow them to meet firm sendout under design weather conditions.[64]

Inventory levels are reviewed periodically along with the data made available by the load balancing model[65] to determine what effect actual weather and sendout experience have had on the Company's ability to meet firm design sendout. The Company is then in a position to estimate inventory levels which must be maintained from that point in time in order to meet firm design sendout requirements absent Algerian LNG

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62 7 DOMSC 1, 69(1982).

63 See Table S-3, supra.

64 Inventory may not always be "full" of this date depending on the pending availability of a Sonatrach tender at DOMAC and the Company's contractual requirements.

65 See part IV, supra

deliveries. This constant re-evaluation of the Company's sendout capabilities during the course of the heating season is precisely the type of gas supply planning which addresses the Council's concern that, "... it may be hazardous to rely on (design year) assumptions for short term planning."[66] By ensuring that its inventory are always at levels necessary to meet design peak shaving requirements for the entire remaining heating season without additional Algerian LNG, the Company properly builds the most reliable contingency into its planning.

The second part of the Company's contingency plan are the contracts it negotiated with Dorchester Gas for the supply, terminalling and delivery of 50.0 million gallons (about 4,578 MMcf) of LPG at the Sea-3 plant in Newington, N.H. These volumes are available to the company on an optional basis, with the exception of 5 million gallons firm for use at Danvers. The Company must pay a $200,000 per month terminalling fee during the heating season whether it utilizes the capacity or not. Such an arrangement ensures that the Company can replace with propane the equivalent of the six Distrigas shipments which it would normally receive during the period from November through March.[67]

The Company further responds that, through its various contacts in the industry, it maintains the expertise and knowledge to exercise the second, third and fourth steps of its plan (although not necessarily in that order). They assert that in the event of an emergency which would require additional LNG purchases, the particular circumstances of that

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66 7 DOMSC 1, 45 (1982).

67 In part, this plan is in effect in the North Shore division. The 5 million gallons of propane, which have already been purchased at $0.61/gal., or $6.64/mcf, FOB Newington, will be used to replace the volumes which would have been sent out from the Salem LNG facility under normal circumstances.

emergency would dictate the Company's actions. Thus, the Company has prepared a document containing the names and telephone numbers of all parties who would be contracted to assist in securing such supplies.[68]

The Council views this as an appropriate step which has the effect of reducing the risk in the Company's supply plans. Where key contact people within the Company might be unavailable during a crisis situation, a written standard operating procedures would be available to others within the Company. The contacts could then be made relying on an institutional document rather than solely on personal knowledge. This, however, is only a step, not the entire solution.

If these later steps are required, there will be a regional gas supply problem in all probability. Boston Gas Company is simply too large a company and too dominant a force in the regional gas market for there to be no "ripple" effects in such a situation. As the Council noted in its last Decision:

> "Boston Gas' size limits it from depending on other, smaller systems in the region for emergency gas supplies... While we are encouraged by the apparent flexibility of the gas supply system, we are concerned about the impact of Boston Gas' requirements on regional supply contingencies"[69]

There is a need for Boston Gas to look at the regional implications of possible supply problems, and to plan for contingencies in the event they occur, in concert with the regions' other gas utilities. It was this concern which prompted conditions Nos. 4 and 5 in the Council last decision.[70] Although, as will be discussed presently, the Company has, to a satisfactory extent, fulfilled these conditions, there

68 Forecast, App. "A", p. 14.
69 7 DOMSC 1, 74 (1982).
70 7 DOMSC 1, 75 (1982).

remains a need to improve regional contingency planning. Condition No. 7, to this decision addresses this concern. The Council will utilize its statutory authority to, "provide a necessary energy supply for the Commonwealth"[71] to assist the Company and the Executive Office of Energy Resources in achieving that end.[72]

In response to Condition No. 5 of the previous decision, the Company has committed itself to the fulfillment of its requirmenets to evaluate the various regional supply and storage requirements, ".. once the (Council) staff has had the opportunity to determine (how) this issue should be pursued."[73] The issues raised in the Condition cannot be properly addressed until there is some resolution of the Council's proposed rule-making on LNG storage facility siting regulations. When this issue is resolved, the Company will diligently pursue fulfillment of the Council's Order. This commitmert satisfies the present requirement of Condition No. 5, however, we will continue this Condition in effect until such a time as circumstances permit the Company and the Council staff to move foreward. Condition 9 addresses this issue.

D. THE NEED FOR NEW OR ADDITIONAL FACILITIES

In our last Decision, we directed the Company to utilize its analysis of potential need for new facilities in order to fulfill conditions concerning conservation, the relative costs and risks of supplemental fuels and contingency planning.[74] Since that time the Company has sought and received the approval of the Council for improvements to its Danversport LPA facility,[75] consistent with our directive.

71 M.G.L. c. 164, sec. 69H.
72 M.G.L. Ch. 25A, sec. 6(1).
73 Forecast, App. "A", p. 11.
74 7 DOMSC 1, 76 (1982).
75 EFSC No. 82-25A; 8 DOMSC ____, (1982).

1. The Spencer LPA Facility

The Company proposes in this filing to construct a new 3.6 MMcf/day LPA plant in its Spencer division with an associated storage capacity of 1,652 Mcf of propane.

a. The Spencer Division

Consisting of the towns of Spencer, Liecester, Warren and the four Brookfields, the Boston Gas Company's Spencer division serves 2,989 customers. The system distribution pressure levels are designed to operate at a minimum of 25 psig and a maximum of 62.0 psig; however, the Spencer interconnection with the TGP lateral at its city-gate station operates at 100 psig under normal conditions.

Pipeline gas is delivered to the Spencer division under the CD-6 rate tariff at TGP's Spencer Sales Meter Station ("The Station"). The Station is connected to the TGP pipeline by an 8.6 mile, 3.5" diameter lateral pipeline which is owned by TGP. This is the sole source of pipeline gas for the Company's Spencer division and its only take station.

Boston Gas' submits that its contractual MDQ at Spencer, 3.8 MMcf/day provides sufficient volumes to meet the current requirements of its firm customers up to a 63 degree day ("DD") level or when mean daily temperature at Logan Airport is 2°F. According to the Company, on days colder than 63 DD, the Spencer division can only be served by pipeline volumes which exceed MDQ or suffer curtailment.

b. Need for the Facility

The design peak day for the Spencer division is 73 DD, measured at Logan Airport and is based on an actual peak day of 61 DD (January 4th, 1981). On that actual peak day, the Spencer division sendout was 3.766 MMcf; however, as noted on Table S-7, supra, that was not the Spencer division's peak sendout. Peak demand and sendout occurred on January 11th, 1981 and was 4.073 MMcf, or 4.4% in excess of division MDQ.

During such peak periods, system pressure at the Spencer Station falls below the 100 psig, a level which is necessary for the proper functioning of the division's regulator equipment. The pressure drop below 100 psig may ultimately affect the proper functioning of consumer appliances. The low pressure is caused by a significant drop in pressure in the 8.6 mile lateral due to the high flow rate caused by increased demand ("friction loss"). The historical problem with such friction loss is demonstrated by Table S-10.

On design peak day, the Spencer division sendout as forecast will exceed the pipeline MDQ. This forecast is supported by an actual peak day sendout exceeding of MDQ on a day which was 16 DD's below design peak (January 11th, 1981). The facility then is needed to meet both pressure and peak day requirements.[76]

At the public hearing held in Spencer the evening of October 21st, 1982, there was considerable sentiment expressed by the residents of the division in support of additional gas service. One resident complained of fruitless attempts to get gas heat service for residences which he had constructed, despite the fact that he had purchased and installed gas appliances and had been placed on the Boston Gas "hook-up" list.[77] A second resident and representative of a large industry in the area (Flexicon, Inc.) complained of having gas service curtailed during cold

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76 This discrepancy underscores our concern that the Company better forecast the temperature sensitive portion of load growth and exisitng load.
See part IV.D. supra.

77 Tr. pp. 23-27.

Table S-10

Boston Gas Company

HISTORICAL FRICTION LOSS IN THE SPENCER DIVISION

Split-Year	Date	Degree Day[1]	Minimum Pressure (psig)	Daily Sendout MMcf at 1000 Btu/scf
1980-81	1/5/81	55	40	3.241
1980-81	1/8/81	50	70	3.557
1980-81	1/11/81	57	80	4.073
1980-81	1/13/81	51	80	3.637

1 measured at Logan Airport.

weather. The same representative testified that he had agreed to take more gas from Boston Gas on a firm basis in 1986 when his Company's plant expands.[78] The only other major concern directed to the Council at the hearing was the concern that possible pipeline improvements be considered as an alternative.[79] The desire of the residents of the division for gas service, and, in particular, the indication from the Flexicon Corporation representative that his Company's plans for expansions and use of process gas were firm are important. They indicate support for the Boston Gas assertion that additional volumes are necessary in the Spencer division in order to meet peak shaving requirements due to growth in sendout.

Boston Gas forecasts its peak shaving requirements in the Spencer division will rise from 580 Mcf in the 1982-83 split-season to 3,600 Mcf in 1991-92. The increase in demand on peak is forecasted, for the most part, consistent with the overall Company forecast methodology.[80] Therefore, it is reliable to the extent the Council has determined that methodology to be reliable. The Spencer forecast is adjusted, however, for the actual knowledge of peak industrial load additions in 1987 and 1990-91. As is reflected in Table S-11,[81] this growth in peak does not change the basic need for additional volumes on peak in the division. Rather, this growth defines the quantity of additional volumes which will be needed. Thus, depending on the size and type of facility constructed, this growth will affect the load factor and cost-efficiency of the facility.

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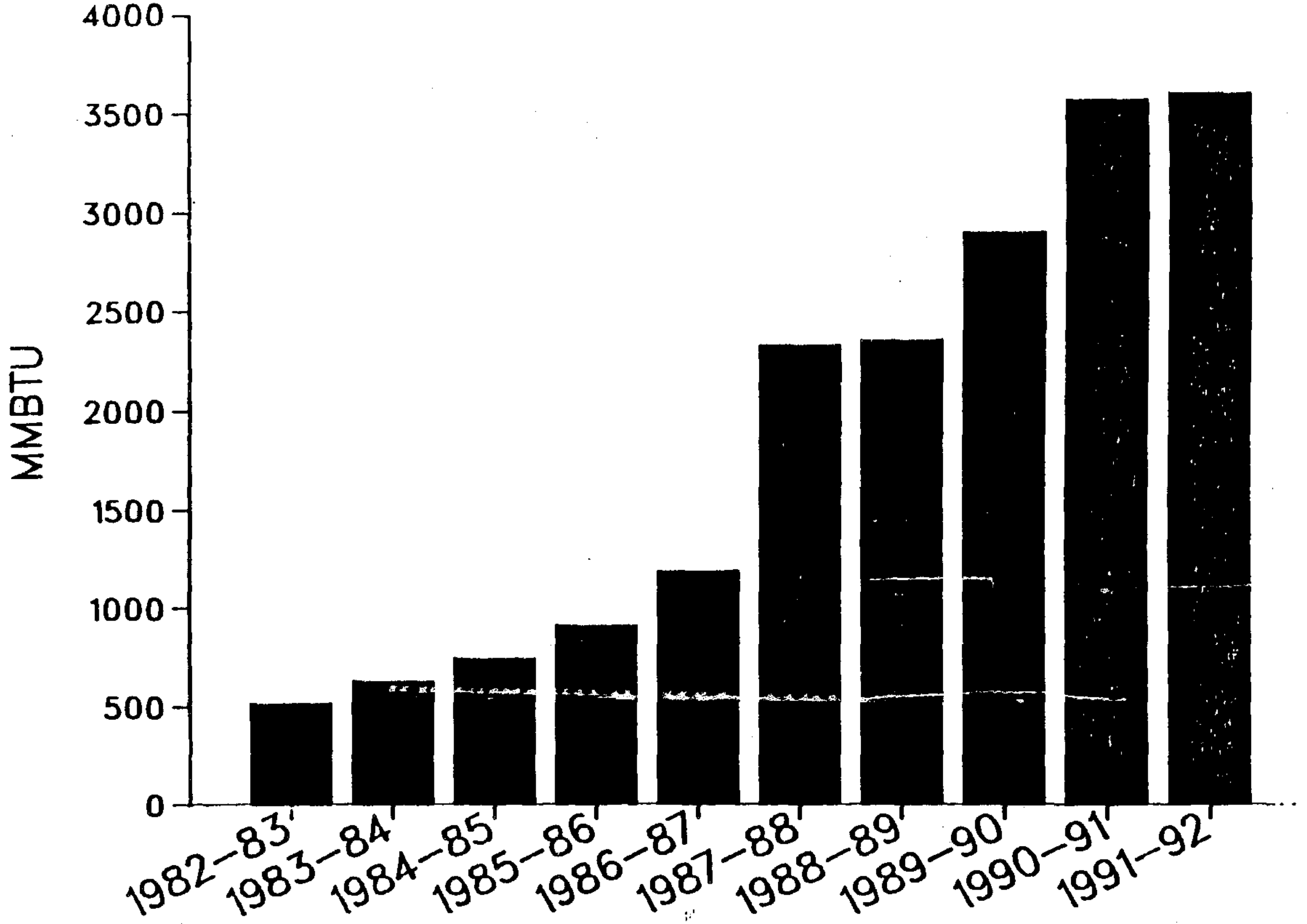
78 Tr. pp. 76-77.
79 Tr. pp. 66-73.
80 See part IV.B, <u>supra</u>.
81 BGC Ex. A-2.

Table S-11

Boston Gas Company
DESIGN PEAK REQUIREMENTS FOR THE SPENCER DIVISION



c. The Proposed LPA Facility

Boston Gas has proposed to construct a liquid propane-air facility on three parcels of land which it presently owns in the Town of Spencer. The total area of the land is 4.8 acres, located on the easterly side of the lower end of Valley Street. The parcel of land on which the facility would be constructed is approximately 300' east of Valley Street and connected to that public road way by a 12' wide access road owned by Boston Gas. Land to the southwest of the Proposed facility is owned by the Town of Spencer and includes am athletic field.[82] To the north and northeast, at a distance of 350-500' are residential, single, and double family wood frame dwellings. To the southwest and east is a spur from the Boston and Albany R.R.

On this parcel, the Company currently operates its Spencer TGT take station. The Company's measurement, pressure regulation, and conditioning (odorizing) of the pipeline gas is conducted in a single story concrete block building located on the property. It is from this point that Boston Gas takes TGP gas and redelivers it to its customers in the Spencer division.

Boston Gas proposes to install LPG storage amounting to 18,000 gal. (water capacity or "W.C.") or approximately 1,600 Mcf. This capacity would provide self sufficient capacity for the plants design production capacity of 150 Mcf/hr. for approximately 10 hours. The proposed tank would be a horozontal type and would be sited in the center of the tract. The Company would bury and mound the tank so that it would be completely

82 The State Representative from Spencer is on the record in support of the facility, provided that the Company ensures the safety of Spencer residents and adequate security. Tr. pp. 9-10.

covered except for piping connections, vents, a small walk way and access stairway, and relief valve.

At the entrance to the facility at the access road, the Company proposes a transport turn-around area and parking facility to handle LPG tank trucks. A transport unloading station would abut this turn-around and be connected to the storage tank by two pipes: one pipe serving to transport the liquid propane to the tank; the other serving to equalize vapor pressure between the vehicle and the tank. Two pipes would lead from the tank. The first would carry the process liquid to the water/-bath vaporizer, the second, a natural gas pressurization line leading from the compressor room.

Approximately 75' to the SW of the tank, the company proposes to install a water bath vaporizer having a design capacity of 1,650 gallons of liquid propane per hr., or the equivalent of 150 Mcf/hr. of natural gas. In the water bath, fuel gas is burned in the lower portion of the rectangular structure to heat the water in the upper portion. Liquid propane is conducted through a coil which is immersed in the heated water. The heat is transferred to the coil and propane is vaporized during the endothermic reaction which ensues.

Once vaporized, the propane gas is mixed in the proper proportions with compressed air. The two air compressors installed will each be capable of delivering 500 cubic feet per minutes at a maximum discharge pressure of 125 psig. These compressors would be housed in a compressor room to be built adjacent to the existing structure. The mixing of air

Table S-12
Boston Gas Company
ESTIMATED COSTS
SPENCER PROPANE/AIR PLANT

Description	Estimated Cost
Sitework	$ 6,000.00
Foundations and Building	20,000.00
Piping and Mechanical Work	40,000.00
Storage Tank	22,000.00
Electrical Work	15,000.00
Vaporizer	35,000.00
Instrumentation and Control Systems	40,000.00
Engineering Design, Specifications and Bid Preparation	25,000.00
Total Estimated Cost	$203,000.00

and gas would take place in the mixing room, in the same structure. The Company is proposing a "state-of-the-art" electronic radio control system. This system would blend the 100 psig air with the propane vapor at a 57% propane to 43% air ratio to produce a gas of 1,400 But/scf at 100 psi. This mixture would then be mixed into the Spencer distribution tie-in pipeline as allowed by the natural gas flow-by volumes.[83] The estimated cost of these improvements is $203,000.00 (1982 dollars) and is broken down by component in Table S-12.

d. Alternatives

A number of alternative solutions to the Spencer division peaking problem are available to the Company. Each will be discussed in turn, comparing relative cost, reliability and environmental impact.

i. Relay of Lateral Piping

The Company estimates that TGT would have to relay approximately one half of the existing 8.6 mile lateral in order to resolve the pressure problem in the division. This would involve digging up or removing over four miles of pipeline and replacing it with pipeline of a larger diameter. The estimated cost of this alternative is approximately $360,000. Relaying this portion of the lateral could solve the capacity problem in the Spencer division and reduce pressure drops due to friction loss.

Implementation of this alternative has two major problems, however. The first is that relaying the pipeline would not increase the peak MDQ of the division. As we have noted, the actual peak sendout in the

83 LPG can be mixed up to a 50/50 mix with natural gas without causing operational problems in customer's appliances.

Table S-13

Boston Gas Company

HISTORICAL AND FORECASTED PEAK SENDOUT REQUIREMENTS
SPENCER DIVISION

Split-Year	Peak Day Sendout (Mcf)	Sendout in Excess of MDQ (Mcf)
Actual		
77-78	3,097	0
78-79	3,501	0
79-80	3,298	0
80-81	4,073	273
81-82	3,701	0
Forecast Design		
81-82	4,320	520
82-83	4,430	630
83-84	4,543	743
85-86	4,710	910
86-87	4,990	1,190
87-88	6,126	2,326
88-89	6,149	2,346
89-90	6,694	2,894
90-91	7,366	3,566
91-92	7.401	3,601

division has already exceeded MDQ and forecasted sendout indicates that demand for gas on peak will continue to grow.[84] The TGP has indicated that it will not be increasing firm pipeline capacity in the foreseeable future, so the Company cannot at this time rely on TGP for the additional volumes. The Company can, of course, avail itself of its system flexibility as in the past and utilize more supplemental fuels in its large coastal divisions to make TGP volumes available to Spencer. However, since this alternative exceeds the cost of the company proposal by almost 80% and results in a net use of supplemental fuels equal to that which would be used by the LPA plant proposed by the Company, we find that this is not a more cost-effective alternative.

A second problem with relaying the pipeline has to do with potential, albeit temporary harm to the environment. Digging up and relaying the lateral would involve substantial disturbance of the Alder Meadow wetlands complex which surrounds the Stiles Reservior and that part of the Spencer State Forecast through which the pipeline lateral passes.

For both of these reasons we decline to endorse this alternative.

ii. Installation of a Gas Compressor

A second alternative to the proposed LPA plant would be the installation of a gas compressor in the TGP lateral. The compressor would increase the pressure at which gas would be delivered to the division, assuming TGP would allow the Company to install such a facility. However, the cost of the compressor is roughly equal to that of the LPA plant, would not address the peaking problem, and would not add to system flexibility.

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84 See: Tables S-11, S-13.

The siting of a compressor station presents similar environmental issues as does the LPA plant. Both are permanent structures and involve the dedication of small tracts of industrially zoned land to utility use.

We reject this alternative because it is far less beneficial to the Company customers due to the lack of flexibility and peak shaving capacity than the LPA proposal.

<u>iii. LNG</u>

Boston Gas currently has an LNG vaporization facility located in Spencer at their operating plant. The facility is a truck hook-up which provides the Company with the ability to inject volumes of vaporized LNG directly from LNG trucks. The facility has a rated sendout capacity of 0.5 MMcf/day.

The major problem with truck hook-ups for LNG is that they cannot be utilized on an instantaneous basis. That is, if temperatures drop <u>quickly</u> and the system sendout begins to approach design conditions, pressure will drop. The Company must dispatch a tank truck of LNG from Dorchester, Lynn, Salem, Everett or Providence to Spencer to meet this need. Time, then, becomes an important factor in meeting pressure needs and it does not appear that the Company could meet unexpected peaking needs through the use a truck hook-up for LNG. If the Company were to install a permanent LNG storage and vaporization facility (assuming that one could be sited at an appropriate location on or near the existing pipeline system). The cost would be approximately $750,000.00 or 3 1/2 times the cost of an LPA plant. Additionally, Boston would be increasing its peak dependence on Algerian LNG in all likelihood under this scenario, which is a result the Council cannot endorse. The LNG alternative, for all the above reasons is rejected.

iv. Interconnection with Commonwealth Gas Company

At the request of the Council staff, the Company considered the alternative of interconnecting, its Spencer division with the Commonwealth Gas Company. The Spencer division serves 61 heating and 12 non-heating residential customers in western portion of the town of Leicester. Commonwealth Gas provides gas service to customers in the eastern half of that town. In order to interconnect, the Company would have to install a 12" high pressure pipeline over a nine mile corridor, following major roadways in Spencer, Leicester and Worcester. The physical interconnection of a pipeline of this size would have to be located in Worcester due to constraints on the Commonwealth distribution system. The other terminus would have to be at the Spencer take station. This improvement would be necessary in order to insure minimal pressure drop over the length of the entire system. Actual costs for the entire interconnection would be in excess of $2.0 million: ten times the cost of the LPA facility.

Although this option would provide for reliability in the event of a failure of the TGP latteral, the proposed LPA facility would also have the capacity to meet this need on all but peak days. Further, Commonwealth Gas has indicated that it would be willing to provide service to the division only on a "best efforts" basis. For reasons relating to the high cost of this alternative, the relatively small marginal benefit of peak redundancy in case of pipeline failure, and the questionable reliability of supplies on peak, the Council rejects this alternative.

v. Conclusion

Having determined that there is a need for additional sendout capacity in the Spencer division for both growth and reliability, and that the proposed LPA facility is the least cost, environmentally acceptable alternative, the Council approves the Company's proposal.

2. The North Shore Division

In its Decision and Order in the matter of Boston Gas petition via an Occasional Supplement to improve the sendout capacity of the Danversport LPA facility, the Council Ordered:

> "(3) That in the Company(s) next Supplement filing it propose the formal recission of the Councils July 21, 1980 Order (4 DOMSC 50,81) which approved the addition of a 15 MMcf/day LNG vaporizer at the Salem LNG facility, or state why such a proposal would not be wise;"[85]

This condition was ordered because the improvements in the LPA facility in Danvers had the effect of supplying the division with the back-up capacity for the existing two 15 MMcf vaporizers at the Salem facility and, thus, made the additional 15 MMcf of capacity at Salem an apparently unnecessary redundancy.

In its forecast supplement the Company proposes the formal recission of the additional LNG vaporizer at Salem. The Council approves this recission as part of this Decision and Order. We further direct that the Company must submit a new proposal pursuant to 980 CMR parts 7.07 and 7.08 if and when they deem such a facility is again needed. The approval of the 15 MMcf vaporizer for the Salem LNG facility approved by the Council on July 21st, 1980 by unanimous vote is hereby recinded and voided.

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85 8 DOMSC ___ (1982), EFSC No. 82-25A, p. 28.

3. Pipeline Improvements

a. Boundary Gas

As is noted in section V.1.E. supra, Boston Gas formed a corporation with twelve other retail gas companies and one regional pipeline company in the Northeastern United States called Boundary Gas, Inc.[86] Boston Gas precedent agreement with Boundary Gas provides for an ACQ of 5,110 MMcf with an MDQ of up to 13.912 MMcf. Boston Gas now projects these additional volumes to be available at its Mystic/Lynn division take stations and will be available to serve both that division and Boston/Norwood through the interconnection, as well as a small amount in the North Shore division. Boston Gas is presently projecting these supplies to be marketed to firm customers or to use the volumes to "back out" more expensive supplementals.[87]

In our last Decision and Order, we directed the Company to demonstrate and document why Canadian volumes should not be used, in part, to back out more expensive supplemental fuels.[88] The Company has responded

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86 The Boundary shareholders, and volumes per day entitlements are:

	Mcf/day	% ownership
Brooklyn Union Gas Co.	41,699	22.54
Consolidated Edison (NY)	41,699	22.54
Long Island Lighting	23,995	12.97
Bay State Gas	19,000	10.27
New Jersey Natural Gas	14,523	7.85
Boston Gas	13,912	7.52
Connecticut Natural Gas	9,454	5.11
National Fuel Gas Supply Corp.	9,010	4.87
Haverhill Gas Co.	3,210	1.74
Manchester Gas (N.H.)	2,146	1.16
Valley Gas Co.	2,128	1.15
Berkshire Gas Co.	2,109	1.14
Gas Service, Inc.	1.055	0.57
Fitchburg Gas & Electric	1,055	0.57
	185,004	99.48 (loss due to rounding)

87 Response to EFSC-27 Discovery Questions.

88 7 DOMSC 1, 78 (1982).

that Canadian supplies would likely cost $6.94/Mcf delivered in 1982, while actual SNG-1 gas costs range from $11-12/Mcf and propane from $7-8/Mcf. Boston Gas submits that, were this price differential to persist into the time frame during which Boundary Gas volumes will actually be available, the Company would probably "back-out" more expensive supplementals at that time.

The Company's prudence in this matter, viz., taking the Boundary volumes in the divisions which utilize the largest amounts of LNG, LPA and SNG-1 is commendable.[89] The Company has built in yet more flexibility in its supply planning and can make the appropriate decisions as to use of the additional supplies as price and supply availability fluctuate. This response and the similar statement as to Trans-Niagra volumes, satisfies Condition Number 2 of our last Decision and Order.

b. Trans-Niagara

Unlike the Boundary project, the Trans-Niagara (nee: New England States Pipeline) is a more traditional sales agreement. AGT has agreed to transport Canadian volumes purchased by Trans-Niagra to Boston Gas Boston/Norwood division for resale. As noted, the gas will be available at an ACQ of 5,132 MMcf up to an MDQ of 15 MMcf/day. The Company's response to Condition No. 2 of our last decision is identical to that described in the Boundary section above, and is equally satisfactory. The Company is again to be commended for building into its system increased flexibility as to supply source and price.

4. Conclusions

The Council recognizes five major justifications for the need for

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89 Although SNG-1 is only available in the Boston/Norwood division under the AGT contract, transfer of Boundary volumes can take place through the Mystic/Lynn interconnection.

capacity: (1) for system growth; (2) for replacement of capacity no longer available; (3) for displacement of unreliable or expensive capacity or volumes; (4) capacity or volumes which improves the system's economic mix; and, (5) reliability.[90]

As we have noted in the case of the Spencer LPA plant, the need for the facility can be justified on the basis of growth and reliability. Similarly, the Salem LNG vaporizer is now unnecessary because the capacity which is necessary to meet the growth and reliability requirements, which the Council acknowledged in the summer 1980, has been provided by the Danversport LPA plant. That addition also has the advantage of diversifying the division's supply mix and improving reliability in that regard. Lastly, both Canadian gas projects would, if deliveries were made presently, be justified on growth, economic mix, and reliability grounds. These justifications for approval of these facilities as part of the Company's supply plans as forecast are equally satisfactory. The Council approves these projected additions to the Company's future supply as providing necessary energy at the lowest overall system cost and minimum environmental impact given the available alternatives. We will however, continue to closely monitor developments as to the Canadian projects.

E. VOLUMES MARKETED TO INTERRUPTIBLE CUSTOMERS

In our last Decision and Order, we directed the Company to:

> "... document the precise relationship between interruptible sales and the determination of a least cost mix of resources to meet normal firm sendout needs, in particular the extent of and reason for interruptible sales that are coincident to non-pipeline sendout, and how this rela-

90 8 DOMSC ___, EFSC 82-25A, pp. 8-9 (1982); 5 DOMSC 53,89 (1981).

tionship is anticipated to change, if at all, over the forecast period."[91]

The Company responded to this order by describing in some detail how it plans to meet firm design winter sendout requirements.[92] We have described in some detail in parts V.A.1.-4. supra, how the Company plans its supplies to meet design year and peak day sendout requirements. Further, our discussion of "contingency planning" in part V.3. supra., explains why the Company can meet these needs absent Distrigas deliveries during the heating season. In that discussion we noted that the Company plans to meet firm sendout by maximizing, in a prudent manner, its take of available pipeline volumes and meeting peak shaving needs with a mixture of supply which will allow for the maintenance of adequate levels of inventories. This process includes planning for, and having, 5183 MMcf of LNG, 3500 MMcf of ST-1 underground storage gas, and 1,818 MMcf of TGP underground storage gas at the outset of the heating season.

The ST-1 and TGP storage volumes are dedicated volumes and not used for non-heating season sendout below storage capacity. Over the non-heating season, Boston Gas uses its load balancing model to determine firm sendout in the short term and makes periodic judgements about how to fill storage.[93] Based on Distrigas deliveries, existing inventory, and contractual limitations, the Company determines throughout the non-heating season whether to fill LNG inventory with Distrigas volumes or through liquefaction, on a regular basis. This is the Company's first priority after meeting firm daily sendout needs.[94]

91 7 DOMSC 1, 79 (1982).
92 Forecast, Appendix "A", pp. 15-16.
93 See: part IV.D, supra.
94 Forecast, Appendix "A", p. 16.

Once this priority has been met in planning sendout, the Company will market additional volumes, some received under take-or-pay contracts, to interruptible customers. These volumes are those taken under the AGT F-1 rate tarriff and the TGP CD-6 rate tarriff. If more expensive gas is sent out to firm customers i.e., take-or-pay volumes from Distrigas, the overall system mix is still reduced in cost per scf relative to not making the interruptible sales. This occurs because whatever income can be generated by interruptible sales is balanced against payments which would have been made on the take-or-pay volumes even if not taken. If I-1 or R-1 interruptible gas is available from AGT or TGP, the Company will market those volumes to the extent they can be sold over cost. Profits from all interruptible sales are applied to reduce the cost of gas under the monthly cost of gas adjustment proceeding at the Department.[95]

The Company has adequately explained how it determines which supplies are available. They have also explained that, under the present form of rate regulation by the Department, sales of gas to interruptible customers has the effect of improving load factors in take-or-pay situations and reducing the overall relative cost of gas to firm customers. Therefore, the Company has satisfied Condition No. 6 of our last Decision and Order.

F. CONCLUSIONS: SUPPLY PLAN

Boston Gas Company has sufficient resources to meet anticipated sendout requirements on peak day, during a "cold snap" as defined by the Council, and under design conditions. Additionally, the Company has

95 See: DPU No. 1100, pp. 144-156 (1982).

sufficient capacity to deliver those resources in sufficient quantities to each of its divisions with the possible exception of Spencer.

The problem presented by the exceeding of pipeline MDQ, on historic peak day, and recuring pressure problems in the Spencer service territory is one for which the Company has proposed an appropriate remedy: the construction of an LPA plant. We recognize that there is little margin in the Spencer service territory this heating season and direct the Company to closely monitor sendout patterns for that division. This is the purpose of Condition number 10 We direct the Company to proceed with construction of the LPA plant with all due diligence as soon as it gains all necessary regulatory approvals.

The Council is also satisfied that the Company has produced a contingency plan which is adequate for this heating season and provides an excellent beginning to the effort to encompass regional needs in that plan.

VI. DECISION AND ORDER

The Council hereby conditionally APPROVES the First Supplement to the Second Long-Range Forecast of Gas Needs and Requirements of the Boston Gas Company and Massachusetts LNG, and ORDERS:

1. That the Company state explicitly in its next Supplement the conservation rates that it uses for individual customer classes, sendout divisions, sub-classes within customer classes, or all three;

2. That the Company show in its next Supplement how conservation rates change over the forecast period, or, if the rates stay constant, justify why constant rates are forecast;

3. That the Company describe in its next Supplement how it uses its data has to prepare the forecast of conservation rates, and state how potential biases in the data base are taken into account;

4. That the Company adjust the base heating increments in its next supplement to reflect its knowledge of changing usage patterns in its customer classes or sendout divisions, and that these adjustments be documented;

5. That the Company examine the relationship between load growth and the 50+ degree day range and the composition of load growth, that it use the analysis in its distribution of load growth across degree day ranges, and that it document its assumptions and analysis concerning distribution of load growth in its next Supplement;

6. That the Company forecast the daily peaks of each of its sendout divisions in its next Supplement, or explain why this is inappropriate;

7. That in its next Supplement, the Company submit a forecast of sendout requirements separately for its commercial and industrial customers, or, if the SIC coding is not completed, to state the status of the SIC coding effort at that time;

8. That the Company work with the Council staff to assess the regional impacts of a cessation of deliveries of Algerian LNG, to the extent that those regional impacts would be precipitated by the Company's activities;

9. That Condition Number 5 of our last Decision and Order remain in effect and that the Company comply with it, to the extent possible, in its next filing; and

10. That the Company monitor closely the sendout in its Spencer division until such time as the liquid propane/air facility, approved herein, is available to meet sendout requirements in that division.

11. That the Company meet with the Council Staff within 60 days of this Decision and Order for clarification and/or assistance in defining the scope of effort required to fulfill the above conditions.

Paul T. Gilrain, Esquire
Hearings Officer

On the Decision:
George Aronson, Staff Economist

dated this 26th day of November, 1982

This DECISION and ORDER was approved by a unanimous vote of the Energy Facilities Siting Council at its November 22nd, 1982 meeting.

Voting in favor: Dennis Brennan, Esq., Public Member, Gas; Richard A. Croteau, Public Member, Labor; Margaret N. St. Clair, Esq., Secretary of Energy Resources; Bernice McIntire, Esq., for the Secretary of Environmental Affairs; Noel Simpson, for the Secretary of Economic Affairs.

Ineligible to vote: Harit Majmudar, Ph.D., Public Member, Electricity.

Margaret N. St. Clair

Margaret N. St. Clair, Esq.
Chairperson

dated this day of December, 1982

APPENDIX A

Energy Facilities Siting Council
100 Cambridge Street, Rm. 1506 (617) 727-1136
Boston, MA 02202

M E M O R A N D U M

TO: Docket EFSC No. 82-25

FROM: John P. Hughes
Chief Economist JH.

DATE: July 14, 1982

RE: Boston Gas Compliance with the Council's March 1982 Decision and Order

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Pursuant to Condition 9 of the March 29th Order and Decision of the Council approving Boston Gas Company's Second Long Range Forecast, Council Staff met on three occasions with representatives of the Company. 1/ The first meeting, held on March 17, 1982, focused primarily on the Danversport project (EFSC No. 82-25) because of the urgent need by the Company for a decision on that project. By mutual agreement it was decided to delay any further meetings on the conditions imposed in the March Decision and Order until after the Danversport case was completed.

The second meeting was held in the Siting Council conference room on May 20th. At the May 20 meeting, I first outlined in general terms

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1/ See Appendix A for list of attendees at each meeting.

the Council's major areas of concern that need to be addressed in future Boston Gas filings with the EFSC. These are:

1) The marketability (and cost) of Boundary and/or NESP pipeline imports;

2) The potential for more conversions from oil to gas, from both temperature and non-temperture sensitive loads;

3) The Company's planning assumptions and contingencies, with respect to gas price decontrol; and

4) The general belief that with Canadian imports and price decontrol, the regional gas industry could be quickly evolving into a market which is no longer supply constrained.

I informed the Company's representatives that these issues were not specific to Boston Gas' service territory or market area but generic to all EFSC gas filing reviews. I gave them a copy of the EFSC Staff's recent set of discovery questions to Bay State Gas to illustrate how we were developing these issues during discovery. [2/] I told the Company to expect similar interrogatories when their July 1st forecast filing is adjudicated.

The next topic of discussion concerned the numerous "suggestions" [3/] in the March Decision and Order, particularly in Part V(A), relating to the Company's projection of sendout and conservation. The Company was concerned that they might be elevated to the status of formal conditions to the Order and that as such the Company would be obligated to respond to each of them. The Company also sought Council Staff interpretation of the scope and meaning of these "suggestions". The Council Staff explained that these "suggestions" were not intended to be additional conditions imposed on the Company nor were they intended to place an

[2/] See Appendix B for copy of discovery questions to Bay State Company.

[3/] These were presented in the form of directives in the narrative of the Decision, but were not mentioned or repeated in the formal conditions of the Decision and Order.

additional burden on the Company beyond the normal conduct of business operations. The Staff further explained, however, that in some instances the suggestions were essential to make the Company's methodology reviewable. Such suggestions generally fell into three broad categories:

(1) Better document the forecast methodology;

(2) Disaggregate data and improve data collection;

(3) Consider the impact of gas price decontrol on demand in general and conservation in particular and document assumptions.

In an attempt to improve the reviewability of its methodology, the Company agreed that it would describe in more detail the process it goes through to develop a sendout forecast, as well as the factors it considers and the assumptions it makes in arriving at the forecast.

With regard to data collection, the Company briefly outlined several projects that it is either currently undertaking or considering undertaking in the near future which will inhance its data collection. The Company agreed to include in its next filing descriptions of these projects and to show how they were incorporated if at all. Beyond including such a description, however, the Company did not commit itself to pursuing these projects if they proved to be of little usefulness.

The Company further agreed to state and explain its assumptions regarding price decontrol and to address how these assumptions are incorporated into the Company's sendout forecast. The Council Staff and Boston Gas recognize, however, the tenuous nature of the factors that must be considered when one develops these assumptions, given the current political and economic climates surrounding gas price degregulation.

The Conditions to the March Order were next discussed in succession:

> "1. That the Company commence a formal study of the relative risks and costs of its purchased LNG, SNG and propane, relating these risks to the Company's on-going determination of its optimal mix of supplemental resources."

I suggest that the Company address this condition in the July filing as follows:

1) Map historical LNG (DOMAC) deliveries to actual sendout requirements;
2) Discuss SNG and propane supply markets; and
3) Speculate on the potential long-run changes in the Company's usage of supplemental fuels.

In the context of this Condition, I also suggested that repackaging some material from DPU 555 might be useful.

> "2. That the Company demonstrate and document in its next Supplement to this Forecast why pipeline gas supplies from Canada should not, in part, be used to back out more expensive supplemental fuels."

I expressed my belief that this Condition was quite straightforward and routine. A simple comparison of the estimated costs for Boundary and NESP imports to the major supplemental fuels which recognized projected market sales growth, seasonal load characteristics and peak shaving requirements would, in my opinion, fully satisfy this Condition.

> "3. That the Company demonstrate empirically in its next Supplement to this Forecast its determination that "conservation gas" supplies be recycled as a firm resource for new customers, be used as a supplemental resource for its existing customer base, or be treated as some ratio of firm and supplemental resources, and how this determination will be reflected in the Company's marketing policies..."

Of importance in resolving this issue is understanding customer behavior during peak, shoulder-peak, and off-peak periods. Whatever data is available on customers' temperature sensitive behavior should be compiled and presented in July filing. Assumptions and operational constraints should also be clearly stated. Suggestions or proposals for future data collection efforts would be helpful.

> "4. That the Company fully comply with Condition 3 of our 1979 Decision (4 DOMSC 51, 55)" Condition 3 required the Company to document how it projects average-use per residential heating customer vis-a-vis conservation.

I suggested that the Company utilize whatever data it has at its disposal to estimate the respective base load factors and heating increments for the average new customer. Any hard data, or speculations, on the household size, dwelling size, etc. of each of these groups also would be helpful.

> "5. That the Company assist the EFSC Staff in evaluating the tradeoffs between additional storage and the deliverability and security of supplemental resources, including propane, vaporized LNG and liquefied LNG."

My interpretation of this Condition, was to help develop a record on the general economics of storage. Potential issues, for example, are: What are the circumstances in which a propane tank would be added to the Danversport facility? How would storage costs (including interest on the inventory) impact the choice to liquefy pipeline supplies versus purchase LNG from DOMAC (ignoring take-or-pay obligations)? I admitted that this condition was quite vague and obligated the EFSC Staff to be much more specific as much as it obligated the Company to comply with it. To the extent that the EFSC Staff has the time and need to develop this issue further, it will do so and the Company should wait for the EFSC Staff to initiate such action.

> "6. That the Company further develop and substantiate its 'contingency plans' to meet projected load requirements in the event of a disruption of LNG supplies from Algeria..."

It was mutually agreed that the narrative of the March Decision adequately explained the requirements of this Condition.

"7. That the Company document the precise relationship between interruptible sales and the determination of at least cost mix of resources to meet normal firm sendout needs, in particular, the extent of and reason for interruptible sales that are coincident to non-pipeline sendout, and how this relationship is anticipated to change, if at all, over the forecast period."

This Condition is a routine request for a good technical description of a controversial aspect of the Company's sales and operations. I suggested that material and exhibits from the DPU 555 (or pending rate case) be recycled for this purpose given the fact that such sales were treated extensively.

The last major topic discussed at this meeting was the use by Boston Gas of certain filings and data 4/ from the electric utilities whose service territory overlapped Boston Gas'. I told the Company that I had no preconceived opinion that this material would in fact be other than of purely academic interest. The material were all public documents, had involved considerable expense to produce, and were freely available to any interested party. It was agreed that Boston Gas would not be expected to compile or produce parallel data for its filing. However, the Company agreed to look at the materials to see if it were useful to the Company.

At the third and final meeting held on June 15, 1982, Boston Gas outlined in some detail the Company's proposed approach to the July 1 filing and provided some general background on the Company's business operations. The latter discussion focused on the unique problems faced by the Company in developing a forecast methodology in the context of a limited gas supply. The Company pointed out that its forecast would

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4/ This material consisted primarily of long-range forecasts for Boston Edison, NEES and Mass. Municipal Wholesale Electric Company as well as appliances saturation surveys for those same companies.

necessarily take a different form than that of an electric utility which must be more concerned with over-all demand within its service territory.

In that context, the Company described what the Company had accomplished to date in terms of market research/demand forecasting, and what additional projects the Company is considering in light of future developments in gas supply and gas prices.

I stated that I was encouraged by the Company's efforts to date. I also commented that the Company should document and explain the status of its various "plans for action" even if not yet completed.

In this connection, I asked the Company to document (1) the reasons the electric utility appliance saturation surveys were not helpful (2) the modifications made to the "Zinder" model approach and the reasons that approach will not be used in this filing. Again, at this meeting I pointed out that complete compliance with the entire laundry list of suggestions contained in the final decision was neither necessary nor even reasonable. Instead, it is important for the Company to explain and document fully what methodology is utilized in the July filing.

Appendix A

Technical Conferences

March 17, 1982

EFSC	Paul Gilrain John Hughes
Boston Gas	John McKenna L. William Law, Jr. Charles Buckley Walter Flaherty William Luthern

May 20, 1982

EFSC	Paul Gilrain John Hughes
Boston Gas	Charles Buckley Chet Messer L. William Law, Jr. William Luthern Leo Silvestrini Jennifer Miller

June 15, 1982

EFSC	John Hughes
Boston Gas	James Hunter Chet Messer Leo Silvestrini Jennifer Miller

APPENDIX B

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Boston Gas Co. for the Approval of its Second Long-Range Forecast of Gas Needs and Requirements	)	EFSC 82-25

DECISION AND ORDER

On July 26, 1982 the Council issued an Order of Notice to the Boston Gas Company ("Boston" or "the Company") requiring the company to publish notice of an adjudicatory proceeding on the approval of the first supplement to their Second Long-Range Forecast. ("Forecast"). A pre-hearing Conference was scheduled for August 31, 1982. Prior to that pre-hearing conference, the New England Fuel Institute ("NEFI"), an association of 1,264 independent retail and wholesale home heating oil dealers and wholesale distributors, filed a Petition to Intervene in the instant proceeding. On August 24th, 1982 the Company filed an Objection to the Motion.

Pursuant to M.G.L. ch. 30A Sec. 10 and 980 CMR part 2.15(2)(2), a party petitioning to intervene in an administrative proceeding must state:

> "... the manner in which the petitioner is substantially and specifically affected by the proceeding, the contentions of the petitioner, the relief sought, the statutory or other authority therefore, the representative capacity, if any, in which the nature of the evidence or argument which the petitioner will present."

We find that NEFI has satisfied the threshold requirements set forth above, to the extent that is possible at this time.[1]

NEFI has averred that they will be substantially and specifically affected by the Council's decision because they compete with the Company for heating market share. They contend that their business will be affected by the Company marketing policy which is affected by Council decisions on the adequacy of supply. Finally, they have set forth their representative capacity. We conclude therefore that, on its face, the petition is sufficient notice to the Company of NEFI's intent. 6 DOMSC at 222 (1981).

The Company contends that NEFI's petition should be denied; or, in the alternative, that their participation should be limited to that of a "participating person" pursuant to 980 CMR part 1.05(3). Boston makes five averments in its Objection, each of which will be discussed presently, in turn.

Initially Boston Gas argues that NEFI has failed in its motion to provide its contentions, the relief it seeks, and the nature of the evidence which it might seek to present. NEFI responded to this contention orally at the pre-hearing conference by focusing on that part of the Company's forecast which pertains to <u>new</u> supplies presently being acquired by the Company from Canada (the, so called, Boundary Gas and New England States' Pipeline projects) NEFI's contention was that by

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1 We note that the nature of the argument and relief sought need only be stated "... as soon as practicable". M.G.L. Ch. 30A section 11(1), 6 DOMSC 219 at 222. (1981).

approving such a supply plan for Boston Gas, the Council would increase the Commonwealth's dependence on imported energy, contrary to established policy. The relief it will seek would be to ask the Council to, somehow, deny to Boston Gas the permission to market or acquire this gas.

We do not here pass on the merits of NEFI's arguments, as such decisions will be based on the record put before us in this proceeding. MGL Ch. 30A sec. 11. Further, it is unclear at this time exactly what remedial action the Council would take if NEFI's case was persuasive, or if state action on this matter is pre-empted by similar regulatory action at the federal level.[2] However, in light of substantial statutory ambiguity as to the Council's role in this matter, and the lack of a working precedent, we feel that examination of such issues against a factual back drop will be most beneficial. NEFI has presented information as to its contentions, limited as they are, and, in a very vague way, described the relief it may seek and the nature of its argument.

As a second matter, Boston Gas avers that NEFI will not be affected by <u>this proceeding</u> as the Company's marketing policies are not here at issue. This is not the case. The Council is required to review the sendout forecasts of all gas companies over a five year horizon. Many factors will affect the validity of that forecast, including the Company's agressiveness, or lack thereof, in marketing the supplies made available to then. The price of gas is, in some instances, in excess of

2 See: ERA Docket No. 81-04NG, (1982).

alternative fuels,[3] thus, gas supplies may not always be in total demand based on price alone.

As a third matter, the Company contends that NEFI's contention that the Company's "expansion of gas markets" will affect its members "makes no sense in the context of these proceedings", as Boston Gas has a responsibility to serve its customers within its franchised service area. As we stated in In Re Berkshire Gas, "... the Company is correct when it avers that we have no jurisdiction to prevent the company from marketing gas when: 1) there is supply available; and, 2) there is a demand for gas by the residents of the Commonwealth". EFSC 81-29, Decision and Order, May 13, 1982 at 3.[4] The security of that supply is, however, a matter the council must be cognizant of it is to assure an adequate supply of energy to the Commonwealth. To the extent that the results of such Council approvals of new gas supplies affects the NEFI members ability to serve their customers, they will presumably be affected, although no evidence has been presented to that end as yet.

Lastly the Company avers that NEFI's Motion is made in bad faith and is intended to "create regulatory logjams" and "delay administrative approvals". This is of no small concern. The Economic Regulatory Administration strongly suggested that was the case in its "Order Conditionally Authorizing Boundary Gas, Inc., To Import Natural Gas From Canada", ERA 81-04NG, pg. 13-15, 24-33, 36-39. NEFI's lack of activity in the Berkshire Gas case would seem to belay this concern; however, we

3 See: Platt's Oilgram Price Report, August 31, 1982.

4. We note again that the law does not guarantee Boston, or any gas company, a fixed service territory. MGL Ch. 164 sec. 76, 86, 88.

feel that, because of the acute competition which exists between the industries, we must retain a firm control on the proceedings.

We find that NEFI's participation may well aid the elucidation of the issues in this proceeding, and that they may help to clarify the Council's role as it pertains to interstate gas pipelines. We will therefore allow their participation as a "participating person" pursuant to 980 CMR part 1.05(3) and limit the scope of that participation to issues involving the marketing of new gas supplies which are, or will be, acquired from foreign sources. NEFI will have the opportunity to present direct evidence, cross examine witnesses, and submit legal memoranda and briefs. Any discovery amoung the parties will be subject to the approval of the hearings officer.

The Petition of NEFI to participate in the instant proceedings in the limited manner discussed above is therefore GRANTED.

It is also ORDERED:

1. That the Company answer fully and in writing all of the attached information and document requests by September 28th, 1982; and,

2. That NEFI submit to the hearings officerany information or document requests it wishes served on the Company by September 21st, 1982.

Paul T. Gilrain

Paul T. Gilrain, Esq.
Hearings Officer

Dated this 8th day of September, 1982.

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Bay State Gas Company for Approval of its Second Long-Range Forecast of Gas Resources and Requirements, 1982-1987	EFSC No. 81-13

FINAL DECISION

Lawrence W. Plitch, Esq.
Hearing Officer

On the Decision:

Juanita M. Haydel

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TENTATIVE DECISION

The Energy Facilities Siting Council hereby APPROVES the Second Long-Range Forecast of the Gas Needs and Resources of the Bay State Gas Company, hereinafter referred to as "the Company" or "Bay State", subject to the Conditions set out herein.

I. INTRODUCTION

A. History of the Proceedings

The proceedings of this case have a lengthy history. The Forecast was filed timely by the Company on December 1, 1981. The Company gave proper notice to the public of the adjudicatory proceedings by publication in newspapers in its service territory. Council Staff prepared a set of discovery questions, which was sent to the Company on January 6, 1982. Aside from the 14 Document Requests, which were duly answered[1] on February 5, 1982, the remaining questions were intended to serve as indications of the staff's intentions and as an agenda for a future technical session. As such, they were not answered by the Company. Due to a turnover in technical staff assigned to the case, the technical session was not held as planned.

A second set of information requests was sent to the Company on April 28, 1982. The responses to those questions, a few of which were included in the original set of Information Requests, were received by the Council staff on June 1, 1982. Shortly therafter, a second staff change occurred and the Bay State case then fell to the third technical staff member to be lead analyst on this Forecast. A new set of Infor-

1 Document Request No. 5 asked for the Company's Annual Sales Plan, an internal marketing study that outlined Bay State's strategies for achieving its planned sales growth rate. At the request of the Company, this Document was placed under a Protective Order.

mation Requests was sent out in early September, 1982, and responses were received on October 4, 1982. A technical session was held on October 7, 1982, at which were Bay State officials Christopher G. Gulick, Associate Gas Supply Analyst, Roberta A. Orris, Senior Energy Supply Analyst and Thomas A. Sacco, Manager of Gas Supply Planning. In attendance for the Council staff were Margaret Keane, Senior Economist, Juanita Haydel, Technical Analyst and Lawrence W. Plitch, Hearing Officer.

As a result of concerns raised by the staff at the Technical Session, an additional set of written responses was received from the Company on October 12, 1982. With the receipt of Bay State's November 5, 1982 filing, in compliance with Administrative Bulletin 82-1, the record was finally closed.

The Council regrets the staff turnover which has prolonged this adjudication and appreciates the responsiveness of the Company in its written and oral submissions.

B. Background

The Bay State Gas Company was formed through the merger of the former Brockton/Taunton Gas Company, Springfield Gas Light Company, Northampton Gas Light Company and Lawrence Gas Company. Bay State is the third largest gas company in the Commonwealth behind Boston Gas and Commonwealth Gas Companies, with total firm on-system sales totalling 32168 MMcf in the 1981-82 split-year, 18 percent of the total gas sales in Massachusetts. In addition to on-system sales, the Company makes firm "off-system" sales to all but two of the other gas distributors in the State and several out-of-state customers. If off-system sales are included, Bay State's sendout surpasses that of Commonwealth Gas.[2]

The Company currently serves approximately 194,400 customers in three divisions: Lawrence, Andover, North Andover, and Methuen in the Lawrence Division; Brockton, Taunton, Attleboro and 28 other cities and towns in the Brockton Division; and Springfield, Northampton and 11 other cities and towns in the Springfield Division. The Figure on page 6 shows the Company's service territory.

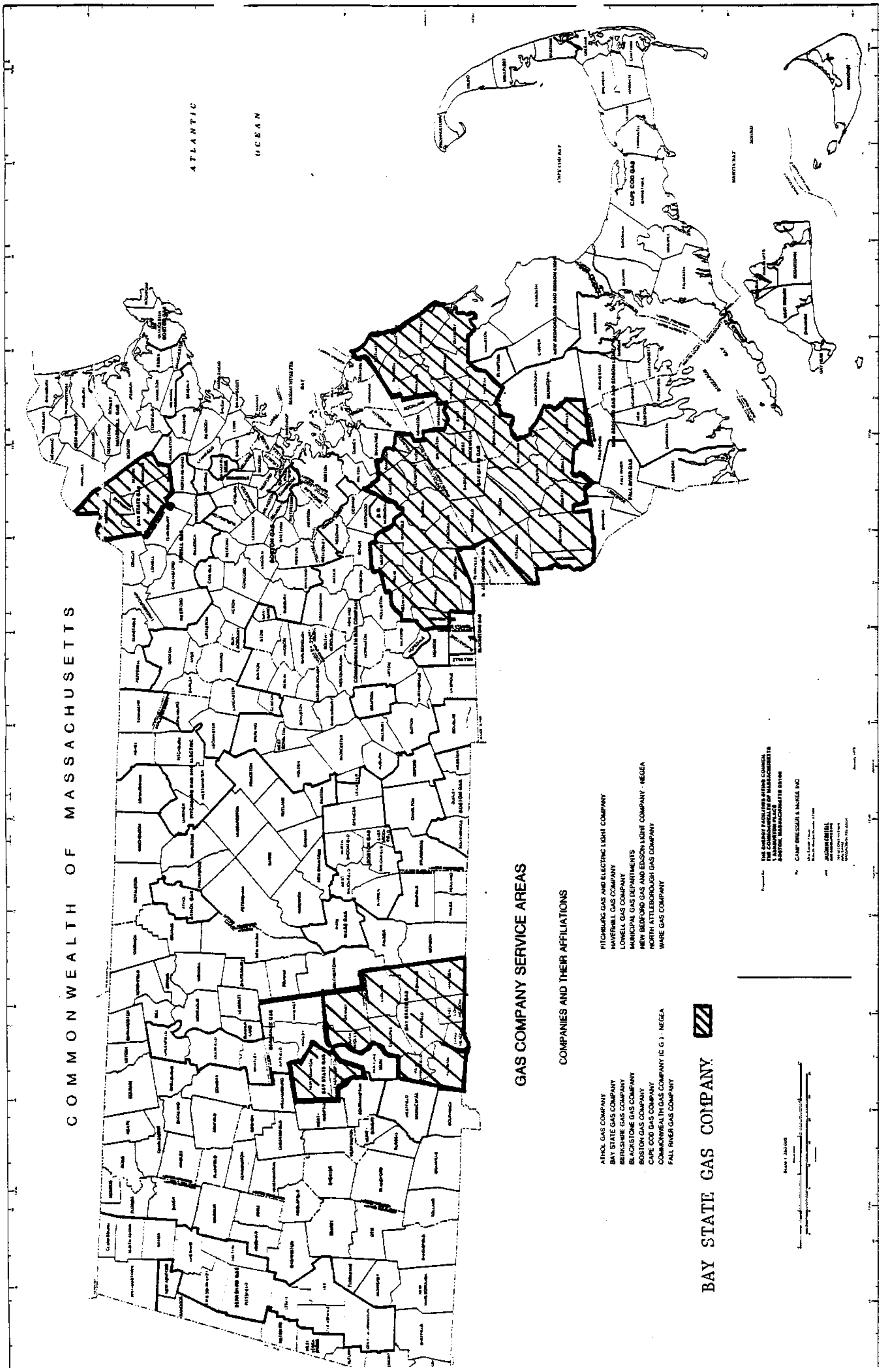
Sales to residential customers represented 55 percent of total on-system sales in 1981-82. Sales to commercial and industrial customers represented 23 percent and 14 percent, respectively, of total on-system sales in 1981-82. Off-system sales represented approximately 9 percent of total sales (including interruptible sales) in the 1981-82 split-year.

In addition to the forecast, discovery responses and testimony, Bay State also provided a Gas Supply Study, prepared by the Company in response to an Order of the Massachusetts Department of Public Utilities in Bay State's most recent rate case (DPU Docket No. 777, January 31, 1982). This document, hereinafter referred to as the "DPU Supply Study", was prepared by the Company in August of 1982, eight months after the preparation of the Company's Long-Range Forecast to the Council.

Insofar as much of the data asked for in the EFSC Forecast is also the subject of analysis in the DPU Supply Study, the latter study was particularly useful in reviewing the Forecast, as a comparative document.

In many ways the two documents were similar. Significant differen-

2 From Tables G-4 and G-5, Bay State and Commonwealth Gas 1981-82 filings.


COMMONWEALTH OF MASSACHUSETTS
ATLANTIC
OCEAN
GAS COMPANY SERVICE AREAS
COMPANIES AND THEIR AFFILIATIONS
ATHOL GAS COMPANY
BAY STATE GAS COMPANY
BERKSHIRE GAS COMPANY
BLACKSTONE GAS COMPANY
BOSTON GAS COMPANY
CAPE COD GAS COMPANY
COMMONWEALTH GAS COMPANY (C G) - NEGEA
FALL RIVER GAS COMPANY
FITCHBURG GAS AND ELECTRIC LIGHT COMPANY
HAVERHILL GAS COMPANY
LOWELL GAS COMPANY
MUNICIPAL GAS DEPARTMENTS
NEW BEDFORD GAS AND EDISON LIGHT COMPANY - NEGEA
NORTH ATTLEBOROUGH GAS COMPANY
WARE GAS COMPANY
CAMP DRESSER & McKEE INC
BAY STATE GAS COMPANY

ces fell primarily into two categories: those that were purely a result of changed circumstances over time and those that reflected the fact that the studies were prepared for two different regulatory bodies, each with its own set of policies. These similarities and differences are discussed in the sections which follow.

In the staff's attempt to responsibly review the Company's Second Long-Range Forecast, all sources of information in the record were used so as to obtain a complete and accurate picture of the Company's resources and requirements. To this end, in addition to the normal practice of referring to Information Request responses and tables from the Second Long-Range Forecast for authority, where appropriate, parts of the Decision also cite to the noted DPU Supply Study.

II. PREVIOUS CONDITIONS

The Council's Decision in review of the Company's Fourth Annual Supplement imposed six Conditions, as follows:

1. That, in subsequent filings, the Company provide the conversion factors in order to convert to an MMCF basis at a BTU content of 1000 BTU per cubic foot at 14.73 PSIA day all gas data presently given in MMBTU's.

2. That the Company perform a study of future customer requirements in order to develop a long-term forecast as a framework within which periodic adjustments to its marketing and supply procedures can be made in order to meet the goal of 3% net growth per year.

3. That the Company base its next forecast of supply from Distrigas on a comprehensive picture of the Algerian situation and likely occurrences, including the most recent information

and forecast available from Distrigas.

4. That, before its next filing, the Company complete an analysis concerning the use of annualized factors to forecast a peak day load, and describe the method of analysis and its results in the Forecast. If the Company does not change its methodology so as to use seasonal and daily factors rather than annualized factors, it should at least discuss how seasonal and daily characteristics are accounted for in the use of the same annualized base load and heating load factor for both non-heating and heating seasons.

5. That, in its next filing, the Company discuss the economic effects on its existing customers of a possible underestimation of future gas supply and overestimation of future customer requirements resulting in "surplus gas". This discussion will be more useful if the Company quantifies different possible scenarios.

6. That the Company submit to the Council as part of the next filing, due September 22, 1981, an analysis of the cost effectiveness of displacing insecure and expensive supplemental gas supplies during the heating season with conservation "supply" through the implementation of "zero interest loan program", the submittal of which has been required by the Secretary of Energy Resources of the Commonwealth pursuant to a letter dated April 24, 1981, and Chapter 465 of the Acts of 1980.

The Company has complied satisfactorily with Conditions 1 and 6 in its filing and in response to Staff Information Request.[3] All other Conditions and the Company's responses are discussed, infra.

III. Sendout Forecast

A. Standard of Review

In its review of forecasts and supplements thereto, the Council requires each gas company to project "the gas requirements of its market area" over a five year period and to describe "actions planned to be taken by the company which will affect capacity to meet such requirements..." GL c. 164 sec. 69I. Under EFSC Rule 62.9(2), forecasts of sendout must be based upon historically accurate information and reasonable statistical projection methods. In its Decisions of recent years, the Council has found statistical projection methods to be "reasonable" if they are reviewable, reliable and appropriate. A methodology is reviewable if it is clearly and thoroughly described or documented, so that its results may be duplicated by another person given the same information. It is reliable when it provides a measure of confidence that the assumptions, judgements and data which comprise it will forecast what is most likely to occur. A methodology is appropriate when it is technically suitable for the size and nature of the particular system.

With these criteria in mind, the Company's sendout forecast will be reviewed.

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3 Response to Question No. 4, Information Requests, February 5, 1982. (Condition 1)

B. Sendout Methodology

1. Description of Methodology

The Company prepares its forecast of future sendout requirements using the ordinary least squares regression technique. Actual sendout data for each of its three divisions for the twelve month period September, 1980, through August, 1981, is used. The Company regresses average firm daily sendout by month (normalized) on average Logan Airport-Bedford Airport degree day data for those same months. This is first done for the three Bay State Divisions and then aggregated. The aggregate, or system-wide equation is the sum of the intercept terms and the regression coefficients for the three divisions. The Company states that the intercept term approximates the base load (non-heat sensitive load); that is, the average daily amount of gas, on an annual basis, that would be expected to be sent out on a zero degree day. The heating increment is sendout (in MMBtu) per degree day.

The Company then assumes a 3 percent system-wide net growth rate in firm sales in both the base load and heating increment. In addition, the Company has assumed that growth will be uniform in all divisions. Table 1 shows the forecasted base loads and heating loads for the Bay State Company, as well as a sample calculation of forecasted normal firm sendout for the 1982/83 split-year.

In allocating total projected firm sendout by customer class the Company proceeds in the following manner: The Company states that split-year base use and heating use per residential heating customer is "assumed to remain unchanged from the most recent split-year calcula-

Table 1

Bay State Gas Company

Base Load and Heating Increment (Firm On-System Sales Only)

Split-Year (April 1-March 31)	Base Load MMBtu/day	Heating Increment MMBtu/DD
1981-1982	28,827	3531.7
1982-1983	29,692	3637.7
1983-1984	30,583	3746.8
1984-1985	31,500	3859.2
1985-1986	32,445	3975.0
1986-1987*	33,418	4094.2

Normal Sendout(1982-83) = (29,692)(365) + (3637.7)(6222) = 33,471,349 MMBTU

SOURCE: Forecast, pg. 18

* The Base Load and Heating Increment for 1986-1987 were not supplied in the Forecast, but were calculated based on 1985-86 factors.

ted".[4] The average use per customer for the residential without heating class is assumed to increase "slowly over the forecast period based on past experience".[5] The Company then allocates total firm sendout to these two classes in a "manner consistent with their respective split-year (customer use) factors".[6] Sales for resale are forecasted at then existing contractual levels. The remaining gas is than allocated to the commercial, industrial and company use classes in a "subjective manner that is consistent with historical data and Company expectations".[7] The Company further states: "The primary focus of the Company is its ability to meet total firm requirements. Gas that is sent out to any firm customer class is the same gas that is sent out to any other firm customer class. It is with this in mind that the Company plans its supply and sendout requirements".[8]

In sum, the Company determines a normalized base load and heating increment using the most recent actual sendout and degree day data. It is assumed that the Company will experience a net growth rate of 3 percent per year. Both the base load and heating increment are assumed to grow at a rate of 3 percent per year. This aggregate firm sendout for each forecasted year is then distributed to customer classes based in part on customer use factors, historical data and judgement..

The Council has several concerns with the Company's forecast methodology, of which only the more general are discussed here. Those more specific concerns are addressed throughly, _infra_.

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4 Response to Question No. 3, Information Request No. 3, Oct. 4, 1982
5 _Id._
6 _Id._
7 _Id._
8 _Id._

The Council expresses concern with the use of such a simplistic methodology by the third largest gas Company in the Commonwealth. Two basic problems are addressed here. First, the Company has assumed for forecasting purposes that the base load and heating increment will remain constant throughout the year. As has been noted in the forecast of other Massachusetts gas companies, as well as in past Council Decisions,[9] customers consume more gas per degree day during severely cold weather and less per degree day during warmer weather. While cold temperatures do occur during the non-heating season, use per degree day during this season is less than during the winter heating season at similar temperatures.

The Company, in response to a Staff Information Request,[10] has argued that some companies use large winter base use factors as one approach to accounting for increased use of gas by certain appliances during the heating season. The Company argues that this increase is in fact temperature sensitive and leads to an expectation of increased use per degree day during the winter season. This in turn has the effect of lowering base use in winter months. While the Company argues that both conclusions are equally valid, it has failed to explain how it accounts for this in its forecast of sendout requirements. It has also failed to identify how variations in temperature effect winter heating increments.

The Company realizes, of course, that base use does vary by time of year and has informed the Council that while it uses these annual factors in forecasting long-term requirements, it does not use them in its daily dispatching operation. Daily dispatching estimates are

9 In Re Boston Gas, 7 DOMSC 1, (1982).
10 Response to Question 20, Information Requests, June 1, 1982.

developed using an up-to-date weather forecast, the previous day's temperature, and the previous day's heating increment. While it is commendable that the Company monitors these factors daily in determining day-to-day sendout, the Council feels the reliability of the Company's forecast would be greatly improved were it to incorporate these short-term factors into its forecast. The Company should demonstrate to the Council that it understands the factors influencing base load and heating increment, including weather and customer classification. With the Company's historical sendout data and daily dispatching information it would seem that the Company has the data base with which to do this. The Company is directed to meet with the Council Staff to discuss these issues further. (<u>See</u> Condition 5).

Secondly, for the Company to assume that both base load and heating increment will both increase at 3 percent per year is questionable. If the Company's goal is to increase total firm sales by 3 percent, the rates at which base load and heating increment grows is certainly a function of the temperature responsiveness of future load additions and load losses. The assumption that peak load will increase 3 percent per year is also dubious. Requirements on a peak day will be affected by the temperature responsive characteristics of the new load additions. The Company's historical data show that while total firm sendout has increased at a compound rate of 2.3 percent per year from 1976-77 to 1980-81, peak day sendout has increased 6.0 percent per year in those same years. Certainly this simplistic analysis is not conclusive but it illustrates the need to account for the temperature responsive characteristics of new, as well as existing load.

2. Company Marketing Policies

Traditionally Massachusetts gas companies have identified the availability of gas and feedstock as the single most important determinant of future sendout requirements. Available supply has been viewed as a constraint and future load growth has been determined compatible with expected resources. In its current filing Bay State appears to have taken this traditional approach to forecasting. The Company has estimated the existing firm base load and heating increment on a system-wide level and then assumed a growth rate which the Company feels it can attain. The Company has stated that its demand potential is greater than its supply capability[11] and that the 3 percent growth rate is "a decision by management which the Company feels it can attain through the use of existing facilities without the addition of substantial distribution or supply."[12] In addition, it is assumed that the 3 percent growth will be uniform in all three of the Company's operating divisions.

As discussed more thoroughly, infra, the Company allocates this existing and new load to customer classes based on historical data and judgement. It would appear that the planning process works in reverse, that is, a growth goal is established and new load is then distributed to customer classes

In the past the Council has found several problems with this "supply constrained" view. First, this assessment obviates the need to fully understand changing customer usage patterns and the factors

11 Forecast, pg. 2.
12 Bay State Hearing, EFSC 80-13, Tr. p. 11, May 11, 1981.

driving those changes. However, changing patterns in customer behavior can change customer demand depending on a wide variety of factors. The Council's mandate is to ensure a necessary energy supply for the Commonwealth, with a minimum impact on the environment at the least possible cost.[13] To be able to meet fluctuating levels of demand with the most efficient supply mix, it is essential that the Company be able to forecast sendout in the short run as accurately as possible, and to demonstrate this to the Council.

In its review of Bay State's Fourth Supplement, the Council expressed concern that the Company did not have a full understanding of changing customer requirements in its service territory, and questioned whether the Company could adjust its marketing and supply planning quickly enough to keep on target. A similar concern was expressed in EFSC No. 79-13. To ensure that these concerns were addressed, the Council directed the Company to perform a study of future customer requirements in order to develop a long-term forecast as a framework for analyzing the magnitude and feasibility of potential adjustments to its marketing and supply procedures. In reply to that Condition the Company has responded that since it already has in place a procedure to continually monitor short- and long-term growth potential along and adjacent to its distribution system, there are no plans to undertake additional marketing studies.[14] The Company states that since its potential load addition is greater than its supply capability the Company is able to be prudently selective with respect to the customers it seeks and to add new customers only when it is in the best interests

13 M.G.L.A., Ch. 164, sec. 69H.
14 Forecast, pgs. 1-3.

of existing rate payers and the Company.

New load additions by market segment and end use category are monitored monthly and compared to projections. When differences are encountered, sales policies and programs are reviewed and required adjustments are made. To further aid in predicting market behavior and in supply planning, the Company maintains customer fuel use profiles to determine when during the day, month or year various segments use fuel for certain purposes. In assessing the long-term potential for customer acquisition, Bay State employs regional population data and projections and U.S. Census data. In addition, the Company states that load is added at a "rate which permits system analysis to indicate where reinforcement of additions to the system will be required". Residential acquisitions are evaluated in the aggregate while each non-residential load request is subjected to a formal system impact evaluation.

While the Company stated it has a procedure to monitor growth potential along and adjacent to its system, it has not explicitly explained what this procedure is and how it is incorporated into its forecasting procedure. In addition, the Company should explain what its policy is with respect to the addition of new load; explicitly, what criteria are used by the Company to determine when it is in the best interests of ratepayers and the Company to add certain types of load. While the Company has provided typical fuel-use profiles for the residential class[15] it has not demonstrated how it incorporates these into its forecast of sendout requirements. The Company is directed to further discuss and document these issues in its next filing. (See

15 Response to Question No. 1, Information Requests, June 1, 1982.

Condition 3).

The second problem with this "supply constrained" view is that it appears to underestimate the effect of price fluctuations of natural gas and competing energy sources. The Company realizes that the price competitiveness of natural gas is a factor in its ability to add to its load and has stated that it feels that total gas decontrol will produce a "long-term market clearing price at the burner tip."[16] However, the Company has not provided any substantiation of this statement, or explained how this will effect its ability to meet its goal of 3 percent growth per year. The Council is concerned that the price of gas, relative to oil, may have a significant impact on the Company's ability to realize its marketing goals.

The Company states that through years of experience it is well aware of the marketing strategies that will influence various marketing segments. It recognizes that some customers are more sensitive to price than others, while others demand dual-fuel capability and others have environmentally based fuel needs. The Company states that this knowledge allows it to predict certain market behavior despite not having the ability to control such behavior.

While the Council realizes that the Company does have considerable flexibility within the context of its supply agreements, in today's rapidly changing energy environment, it is imperative that a Company of Bay State's size establish explicit relationships between changes in customer usage and the factors driving those changes, including the

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16 Response to Question No. 9, Information Requests, June 1, 1982.

price of gas and competing fuels. In future filings the Council expects a thorough discussion and documentation of the impacts of price decontrol on customer usage in all customer classes, including consideration of what the "long-term market clearing price at the burner tip" will be for gas. (<u>See</u> Condition 1).

3. <u>Weather Factors</u>

As do all Massachusetts gas companies, Bay State prepares a forecast of sendout requirements under two sets of weather conditions: normal, a year which is neither warmer nor colder than average, and design, the coldest year for which a company plans to meet firm requirements.

To define a normal year for its service territory, Bay State averages Logan-Bedford degree day data for the thirty year period 1934 to 1963. Thus, the Company uses a normal year of 6222 degree days, 1399 in the non-heating season (April 1 through October 31) and 4823 in the heating season (November 1 through March 31).

The Company plans for a design year which is ten percent colder than a normal year. Bay State uses a design year of 6844 degree days. All additional degree days are allocated to the heating season so that a design non-heating season is comprised of 1399 degree days and a design heating season is comprised of 5445 degree days.

Using the system-wide base-load and heating increment discussed <u>supra</u>, the Company forecasted total firm requirements under normal and design conditions.

A peak day is the coldest day that is likely to occur during a twelve month period. The Company uses a peak day design criteria of 67 degree days, which is based on the actual peak day experiences for the period 1934 to 1963.

4. Class Allocation

The compound annual growth rates for number of customers and sendout, as calculated from the Company's filing, are shown on Table 2 for all customer classes. The number of residential customer with gas heating is forecasted to increase at a rate of 4.6 percent per year over the forecast period, as is total sendout in this class. The number of residential customers without gas heat is projected to decline at a rate of 10.2 percent a year while sendout is projected to decline 9.5 percent per year over the forecast period. The number of customers in the commercial and industrial classes are projected to increase at the rate of 2.2 percent and 1.0 percent per year over the forecast period, respectively; sendout for the commercial and industrial classes increases at the rate of 2.0 and 1.0 percent per year over the forecast period, respectively. Company use and unaccounted for gas increases at a rate of 3.1 percent per year, consistent with Company growth plans.

Figure 1 shows the historical and forecasted number of customers for the total residential class for the period 1977 to 1981. The total number of residential customers (heating and non-heating) increased at a compound rate of 1.3 percent per year. In the current filing the Company is forecasting a 3.4 percent increase per year in the total number of residential customers. While the Company has the ability to limit the number of customers it adds to its system, the Council questions the Company's ability to add residential customers at the projected rate. The Company should demonstrate to the Council that given historical

Table 2

Bay State Gas Company

Growth Rates (compound) Customer Classes (1982/83 - 1986/87)

		Normal Sendout		
	No. Customers (%/yr)	Non-Heating Season	Heating Season	Total
Residential				
with gas heating	4.6	4.6	4.6	4.6
without gas heating	-10.2	-9.5	-9.5	-9.5
Commercial	2.2	3.5	1.3	2.0
Industrial	1.0	1.0	1.0	1.0
Company Use/Unaccounted for	N/A	3.8	3.0	3.1
TOTAL	-	3.0%	3.0%	3.0%

Calculated from Tables G1-G5.

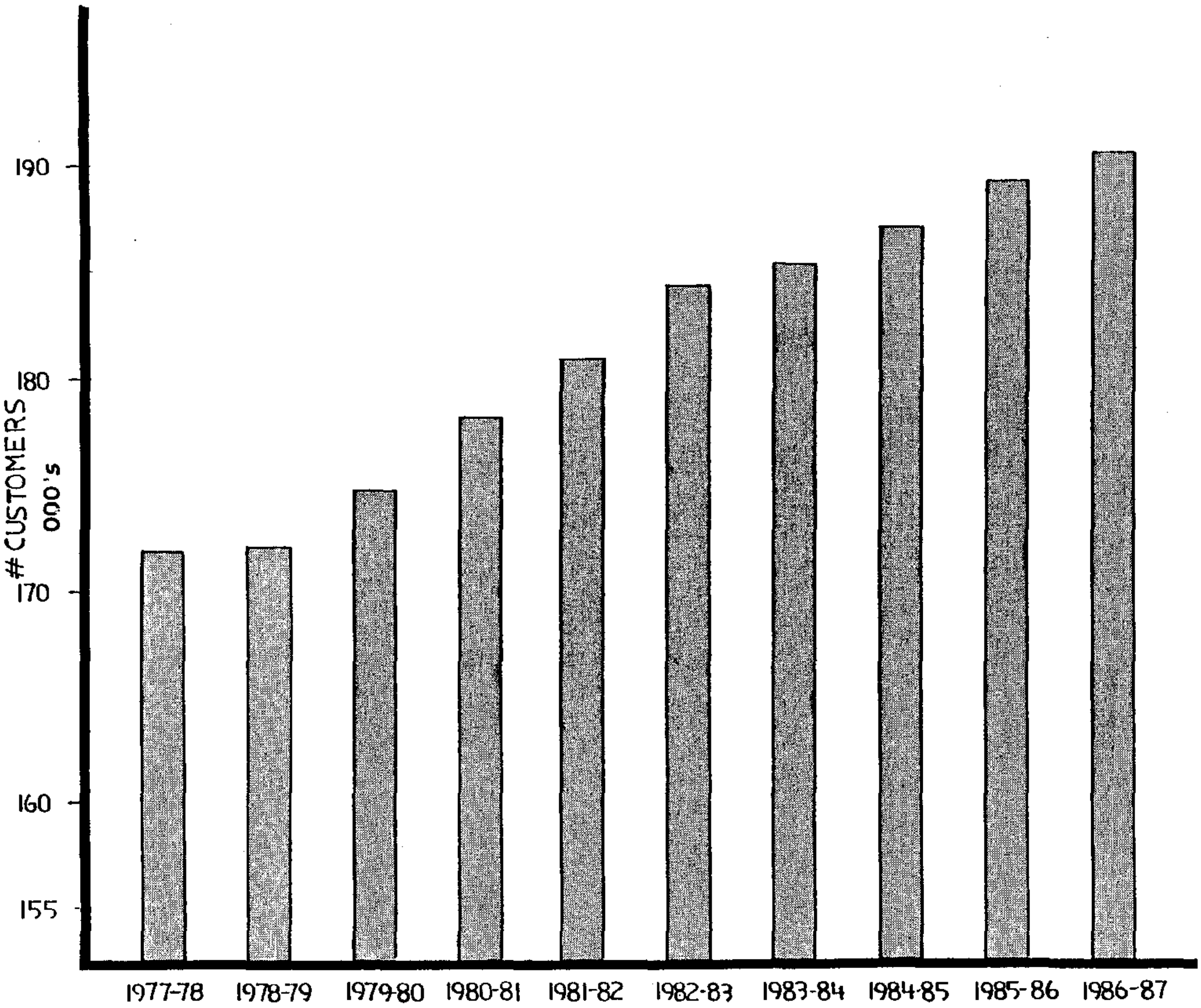

FIGURE 1: BAY STATE GAS COMPANY

1977-78 - 1981-82: Actual
1982-83 - 1986-87: Forecasted

trends, and more importantly the potential impact of natural gas price decontrol, it will be able to achieve the growth rate it is seeking in the residential class. As the decontrol of the well-head prices of most gas supplies is phased in, the Company's marketing ability will be greatly affected, thereby increasing the need for extensive information on the market potential for gas in new construction and gas conversions in the residential segment. (<u>See</u> Condition 1).

The Company allocates gas to the commercial, industrial, and company use classes consistent with historical data and Company expectations. No further explanation or documentation of how firm sendout is allocated to these classes is provided. The historical time period used, how this data is used, and Company expectations are not specified.

Figure 2 shows the historical and forecasted sales for the commercial and industrial markets. Sales to commercial customers grew at a rate of 5.0 percent per year from 1976 to 1982. The Company is forecasting a growth rate of 2.0 percent in the period 1982 to 1987. In its next filing the Company should document its assumptions that commercial sales will increase 2.0 percent per year, given past trends and the impact of price fluctuations of natural gas relative to competing fuels. Any data, judgements or assumptions used, including Company marketing policies, should be explicitly stated. (<u>See</u> Conditions 1 and 4).

As illustrated by Figure 2, sales to industrial customers grew at a rate of 0.7 percent per year from 1976 to 1982. Sales are forecasted to increase at a rate of 1.0 percent. The Company should document its assumption that sales to industrial customers will continue at near historical levels, and relate this to the impact of price decontrol and Company marketing policies. (<u>See</u> Conditions 1 and 4).

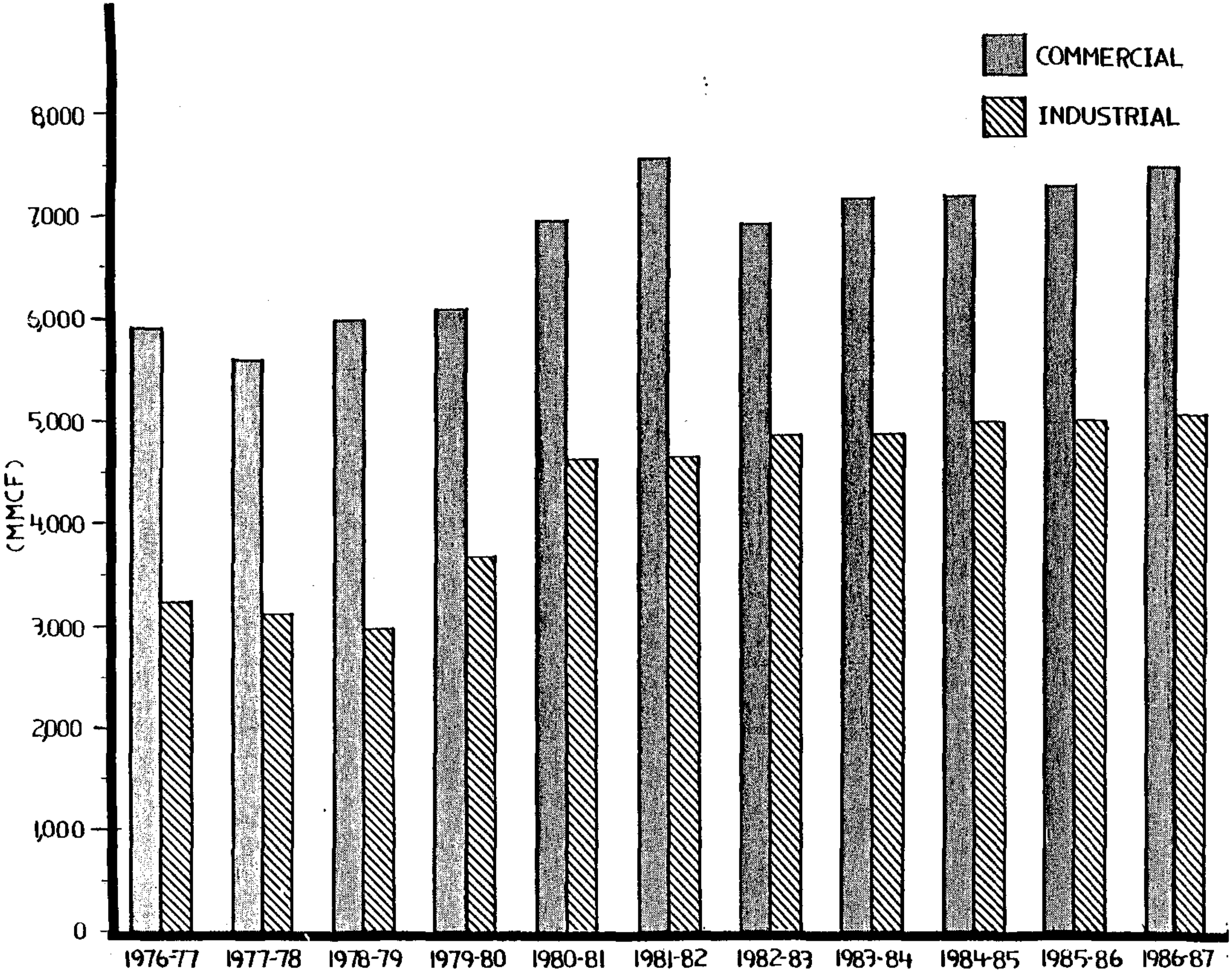

FIGURE 2: BAY STATE GAS COMPANY 1976-77 -1981-82: Actual
1982-83 -1986-87; Forecasted

Another concern of the Council's is the potential loss of firm commercial and industrial customers with dual-fuel capability because of lower prices of alternate fuel relative to the price of natural gas. The record indicates that as of May 1, 1982, the Company lost 59 dual-fuel customers to oil. These customers purchased approximately 1,900 MMCF of natural gas during 1981. It should be noted that this represents an estimate of the potential loss for 1982 within this customer class, not the actual load loss.[17] The record indicates that 40 of the 59 customers who switched to oil have returned to the system on an interruptible basis.[18]

The Company is directed to continue to monitor the impact of No. 6 and No. 2 oil prices, and other alternative fuels, relative to natural gas prices upon its dual-fuel load and thoroughly discuss and document this in future filings. (*See* Condition 1).

5. Customer Use Factors

The Company assumes that split-year base use and heating use per residential heating customer will remain unchanged from the most recent actual split-year. The Company, in its forecast or in supporting information filed separately, has not documented this assumption. Absent this supporting information the Council can only assume that the decision to use the most recent historical data is based on judgement.

The Company further states that sendout is allocated to this class consistent with the customer use factors. If the Company has done this as set forth in EFSC Administrative Bulletin 80-2,[19] as the Company has

17 Response to Question No. 7, Information Request, June 1, 1982.

18 Response to Information Request, October 12, 1982.

19 sample calculation:
Sendout (Res. w/ Heat) = (No. of Customers)(use/customer/degree day) + (No. of customer)(base use per customer)

so indicated, either the projected number of customers or the proportion of total sendout to be allocated to the residential heating class must be derived first. How and in what order, the Company derives the number of customers and total sendout in the residential heating class is not indicated in the record and it can not be assumed that another person given access to the same information and experience would come to the same conclusions with regard to customer use factors, number of customers, and total sendout.

The Company assumes that split-year average use per customer in the residential non-heating class will increase slowly over the forecast period; more slowly than historical data indicates. Again the Company states that this assumption is based on past experience but presents no quantitative analysis or studies to support this. The Council assumes that the projected average use for residential non-heating class is based in part on judgement. Again, we have no basis to believe that another person, given the same information and experience, would arrive at the same conclusion.

6. <u>Conversions</u>

The Company is projecting a sizeable increase in the number of customers to which it will provide service. A comparison of the increase in the number of residential heating customers and the decrease in the number of residential customers without gas heating reveals that a substantial proportion of the space heat conversions will be by customers who presently use gas for non-heating purposes (approximately 75 percent of total conversions throughout the forecast period).

The Council is concerned that the Company does not have a thorough understanding of how the addition of these new heating customers to the residential heating class will affect use per customer in this class. At least one other Massachusetts gas company has noted in its forecast that these customers tend to use more gas per degree day than do existing customers.[20] As noted in the Decision on that filing this might be explained by the fact that customers who converted from oil to gas heat experienced a substantial reduction in heating bills due to the lower prices of gas relative to heating oil which has prevailed in recent years. A second explanation might be that the majority of customers who convert to gas heat are already part of the residential non-heating class and use gas for non-heating purposes, while an existing gas heat customer might use gas for space heating only. One final possible explanation might be that due to the high cost of money in recent years most customers who are able to afford the cost of conversion will likely to be more affluent than existing customers, and have larger homes to heat.[21]

The wide range of possible explanations for varying customer behavior points out the need for the Company to thoroughly examine and document the factors which influence usage. The Council expects a full discussion of these factors in future filings. (See Condition 3).

As discussed supra, the Company is projecting a substantial number of conversions to space heating, both from existing gas customers and from new customers. In response to Staff Information Requests[22] the

20 Boston Gas Company, Second Long-Range Forecast, p. I-15.
21 In Re Boston Gas Co., 7 DOMSC 1, 32-33 (1982).
22 Response to Question No. 18, Information Requests, June 1, 1982.

Company stated that it had no way of estimating the number of requests for conversions it received, since the majority of conversions are performed by gas fitters and plumbers unrelated to the Company. Actual conversions for 1979, 1980 and 1981 are shown in Table 3. The number of residential conversions completed in 1981 was less than half the number completed in 1980.

The Council has a two part concern with the above. First, the Company relies on conversions to space heat for a large part of its load addition, yet it exhibits limited knowledge of the potential number of conversions in its service territory, due to the lack of conversion request data. Secondly, the Council is concerned that the Company has not addressed the impact of natural gas price decontrol on its conversion program. The Council requires that both of these concerns be addressed in the Company's next filing. (*See* Condition 1).

7. Conservation

The forecast states "since the amount of new load added each year is controlled by Bay State and is directly related to Bay State's ability to raise capital and physically hook up new loads, Bay State's gross load addition is currently restricted to about 6 percent per year. However, due to additional conservation and/or load loss by and from existing customers, Bay State is currently experiencing a net growth rate of approximately 3 percent".[23] In addition the Company states that "the base load and heating increments are estimated from a year's worth of firm sendout that include any past conservation efforts by our customers. As a result, the forecast implicitly contains the conservation

23 Forecast, pg. 2.

TABLE 3

Bay State Gas Company

Conversions to Gas Space Heating

	1979	1980	1981
RESIDENTIAL			
New	3,370	3,090	1,557
Existing	2,102	4,518	1,799
TOTAL Residential	5,472	7,608	3,556
COMMERCIAL	260	573	569
INDUSTRIAL	16	19	7
TOTAL	5,748	8,200	3,932

Source: Response to Question No. 18, Information Request, June 1, 1982.

experienced."[24]

If the Company is projecting conservation by existing customers, as is indicated by the Forecast, the customer use factors should reflect this. The Company, however, projects constant customer use factors for the residential heating class, implying no additional conservation by these customers. The record indicates that the Company has, in effect, reflected only past conservation by existing customers and assumed no additional conservation by existing or new residential customers over the forecast period. The Company has not provided any quantitative studies or analyses of residential heating customers to support these judgements, and due to the lack of such substantiation the Council does not consider the Company's method to be a reliable way of incorporating conservation into the forecast.

As has been noted in past Council Decisions," the ability to forecast total sendout accurately depends on forecasted conservation. The key to forecasting conservation accurately is in forecasting usage."[25] In past Decisions, other companies have been directed to consider certain factors in evaluating conservation including, but not limited to, "behavioral methods of conservation (e.g. reducing thermostat settings) and conservation methods requiring capital expenditures (e.g., efficient water heaters, furnaces and appliances, and insulation) as well as whether the significance of these methods can be expected to increase or decrease over the forecast period."[26]

The Company's underlying assumptions regarding conservation resul-

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24 Response to Question No. 5, Information Request No. 3, Oct. 4, 1982.

25 In Re Boston Gas Co., 7 DOMSC 1, 40 (1982).

26 In Re Berkshire Gas Co., 6 DOMSC 114, 118 (1981).

ting from capital investments and behavioral changes, including the effects of natural gas price increases should be more fully explained and documented in all future filings. (See Condition 2).

B. Peak Day Forecast

In the last Bay State Decision, EFSC 80-13, the Council expressed concern over the use of annualized customer use factors to forecast peak day load. The Council, in Condition No. 4 of that Decision, required that the Company perform an analysis of the use of annual factors in forecasting a peak day load and discuss how seasonal and daily characteristics are accounted for in the use of the same annualized base load and heating load factor for both non-heating and heating seasons.

The Company has responded to this Condition in its Second Long-Range Forecast.[27] The period used by the Company in its analysis was December 10, 1980 to January 13, 1981; a period during which no curtailments were imposed and a period which included a range of colder days in excess of 50 degree days. The equation used to calculate predicted sendout was taken from the 1980 filing of Bay State (Sendout(MMBtu) = 26956 + 33467(degree day)). Table 4 shows the results of the study.

The Company states in the Forecast that usage patterns performed as expected through the first part of January, 1981. But as record cold continued, conservation efforts decreased and actual sendout exceeded forecasted sendout. The Company states in the Forecast, "Bay State believes that this reaction was the result of a prolonged cold spell,

27 Forecast, pg. 5.

Table 4

Bay State Gas Company

Date	Degree Day	Predicted Sendout (MMBtu)	Actual Sendout (MMBtu)	Difference (MMBtu)	% Difference
12/17/80	50.0	194,291	194,461	170	.09
12/20/80	55.0	211,025	212,620	1,595	.76
12/25/80	71.0	264,572	265,490	918	.35
01/03/81	57.0	217,718	225,611	8,811	3.6
01/04/81	66.5	249,512	262,763	13,215	5.3
01/08/81	54.5	209,351	235,067	25,716	12.3
01/10/81	52.0	200,984	224,272	23,288	11.6
01/11/81	61.0	231,105	256,601	25,496	11.0
01/12/81	58.5	222,738	244,550	21,812	9.8
01/13/81	53.5	206,009	227,052	21,043	10.2

Forecast, pg. 6

and this reaction would only be repeated in the future if Bay State experienced a similar period of sustained cold weather".[28] The Company notes "there was a high correlation between the predicted actual sendout on the two design days December 25, 1980, and January 4, 1981, which were experienced this past winter".[29]

The Council again expresses concern with the Company's use of annualized factors to forecast peak day load. As is evidenced by the Company's own data, as well as by data submitted by other Massachusetts gas companies, heating use per degree day increases as a function of both outside temperature and the severity of the winter as a whole. Analysis of the Company's test period data (Dec. 17, 1980 - Jan. 13, 1981) indicates that heating use per degree day increased approximately 12% from December 17, 1980 to January 13, 1981.

The Council strongly urges the Company to account for this variability in sendout per degree day in its forecasting of peak day sendout, as well as design year sendout and expects a thorough discussion of this in future filings. (*See* Condition 5).

C. Off-System Sales

Off-system sales represent a large percentage of Bay State's sendout, significantly larger than that of any other Massachusetts gas utility (*See* Table 5). In fact, Bay State supplies all but two of the other gas utilities in Massachusetts (and several outside the State as well).

28 Forecast, pg. 6.
29 *Id.*

TABLE 5

Bay State Gas Company

Projected Annual Gas Requirements (Design Year)*

	On System		Off System	
	MMBTU	%	MMBTU	%
1982-83	34,566,210	89.1	4,216,200	10.9
1983-84	35,572,950	89.4	4,216,200	10.6
1984-85	36,579,692	89.7	4,216,200	10.3
1985-86	37,586,434	89.9	4,216,200	10.1
1986-87	38,593,175	90.1	4,216,200	9.9

* Source: From DPU Gas Supply Study, Chap. 3, pp. 3-5.

There has been a tendency in past Council practices, as well as in DPU proceedings, to treat off-system sales as a lower priority set of customers. For example, a Company's "Sales for Resale" class (Form G-4B) is not accounted for in that Company's total Firm Company Sendout Tables (Form G-5). In a separate forum, the DPU has only recently decided to grant long-term approval to Bay State's off-system contracts, and only then under conditions that include the requirement that Bay State demonstrate that future off-system contracts will not jeopardize the Company's provision of service to its firm, on-system customers. (See DPU Order No. 777, pgs. 60-62).

The Council has already reviewed forecasts from several gas companies that receive off-system gas sales from Bay State. For example, in Docket No. 81-20, the Second Long-Range Forecast of Fall River Gas Company, as was approved by the Council on October 25, 1982, included 263 MMCF/year of firm supply from Bay State Gas Company. This amount represented approximately 4.3% of Fall River's total projected firm sendout for 1981-82. In the Council's review of Holyoke Gas and Electric Department's Second Long-Range Forecast of Gas Needs and Requirements, the Council approved a forecast that included firm winter volumes of 157.5 MMCF of gas purchased from Bay State. (EFSC Decision and Order No. 81-23). These examples illustrate the past Council practice of relying on the gas supplies represented by off-system contracts as firm supplies when reviewing the forecasts of the purchasing companies. To view these contracts with any less favor when adjudicating the selling company's forecast would be somewhat hypocritical. While the DPU, in the context of a company's rate case, may be required to give a preference to the customers in that company's service territory, the

Council is not similarly restrained. In the fulfillment of its statutory mandate, the Council must be equally concerned about the on-system firm customers of Fall River, Holyoke, and the other companies who purchase Bay State gas off-system.

Therefore, it is hereby made an express Condition to the approval of this forecast that Bay State, in all future filings, include its off-system sales figures in all of its pertinent tables, with appropriate designations of which contractual amounts are guaranteed (on peak day), firm and optional. The Council anticipates that, prior to the required filing date for Bay State's next Forecast/Supplement, there will be a meeting held between Company representatives and staff to review the Council's gas forms and tables. It is expected that this Condition will serve as the impetus towards making any associated changes. (See Condition 6).

D. Summary

As discussed in the preceding sections, the Company's methodology is substantially lacking in documentation. The underlying assumptions behind customer use factors and class allocation, among other things, are not provided. The Company's reliance on subjective judgement concerning the impacts of the factors influencing future sendout requirements and the lack of documentation and justification for such judgements renders a large portion of the forecast unreviewable. We have no evidence that another person given access to the same information and experience would be able to duplicate the forecast. Due to the unreviewability of the methodology the Council has little basis by which it can determine the appropriateness or accuracy of the Forecast.

In Decisions and Orders concerning the Company's past filings, the Council has attempted to encourage the development of the Company's forecasting capability. The Company has been conditioned to better document its forecasts and the judgements upon which they are based. It has been directed to complete a study of future customer requirements and an analysis of the use of annualized factors in forecasting peak day load. The Council realizes that the Company believes it has made a good-faith effort to comply with all previous Conditions. We also recognize that changing economic and regulatory conditions will affect the focus of our concerns from year to year. Bay State has made some progress in its forecasting ability in recent years. However, at this juncture, the Council feels that stronger direction is needed in order to ensure that the Bay State forecast is reviewable, reliable and appropriate.

Therefore, the Company is directed to make substantial improvements in the documentation of its forecast of future sendout requirements as outlined in this Decision and as set forth in EFSC regulations 66.5(a) (ii), (iii), (iv), (v), 66.5(b)(i) - (vii) and 66.5(c). We expect the Company to address these issues, as well as specific Conditions listed on pages 75-77, infra, in its next filing.

IV. RESOURCES: SUPPLY CONTRACTS AND FACILITIES

A. Pipeline Natural Gas

Bay State purchases its pipeline natural gas from two sources; Granite State Transmission, Inc. ("Granite State") and Algonquin Gas Transmission Company ("Algonquin").

Prior to April 1, 1982 the Company was a customer of the Tennessee Gas Pipeline Company (Tennessee). Effective on that date the Company, and its wholly owned subsidiary, Northern Utilities, became a customer of Granite State, which is in turn a customer of Tennessee. One of the benefits of this change in suppliers is that due to the larger capacity of the Granite State system, the Company is able to receive greater quantities of its storage return gas on days when Granite State has available space in its pipeline, thereby avoiding costs which would have been incurred had the Company sought and received "firm" transportation of storage return gas. Underground storage and transportation contracts are discussed infra, at pages 40-42.

One of the conditions of the agreement was that Bay State would relinquish a small portion (250,000 MCF) of its Annual Volumetric Limitation to Northern Utilities. However, the Company's maximum daily quantities have not changed. These changes are reflected in the Company's current filing with the Council.

Bay State's current contract under Granite State's CD-1 rate schedule provides for a maximum daily delivery of 65,680 MCF and an annual contract quantity of 23,973,200 MCF. Due to an Annual Volumetric Limitation which was imposed upon Granite's supplier by the Federal Energy Regulation Agency (FERC) in 1974, the Company's present annual purchase is restricted to 20,438,858 MCF. In addition, this annual volume has been subdivided into seasonal components of 10,753,624 MCF and 9,685,234 MCF for the periods April 1 through October 31 and November 1 through March 31, respectively. Enforcement of the seasonal allocations is at the sole discretion of Granite State. This contract expires November 1, 2000, but will continue thereafter unless terminated by either party on twelve month's written notice, subject to FERC approval. Currently, all natural gas which is delivered by Granite State must be used in the Lawrence and Springfield Divisions.

The natural gas purchased from Algonquin is purchased through two contracts under Algonquin's F-1 and WS-1 rate schedules. The Company's F-1 contract provides a maximum daily delivery of 33,434 MCF and an annual volume of 9,027,180 MCF. The contract period runs from September 1 through August 31 each year. Unlike the Company's contract with Granite State, this annual volume is not divided into seasonal components.

The Company's WS-1 contracts provides a maximum daily quantity of 18,198 MCF and an annual volume of 1,091,858 MCF. The contract stipulates that the full contractual volume will be purchased on a take-or-pay basis. Purchases of gas under this contract are confined to the period November 16 through April 15. The Company's F-1 and WS-1 contracts expire on October 31, 1989 and November 16, 1987, respectively, but will continue thereafter unless terminated by either party on twelve months written notice subject to approval by FERC. At the present time all natural gas purchases from Algonquin must be used in the Company's Brockton Division.

In addition to the volumes expected under the two contracts with Algonquin, the Company receives gas on an interruptible basis when Algonquin's sole supplier, Texas Eastern, makes full contract volumes available. Since the Company has assumed that Texas Eastern will supply full contract volumes to Algonquin during the forecast period, it has estimated that 750,000 MCF of this I-1 gas will be available, based on the Company's pro-rata share.

B. Storage Return Gas

The Company has a contract with Consolidated Gas Supply Corporation (Consolidated) which provides for a gross storage volume of 1,622,660 MCF and a maximum daily withdrawal of 14,752 MCF. This contract expires April 1, 2000, but will continue thereafter unless terminated by either party on 24-month's written notice. Transportation of this gas is provided on a best-efforts basis by Granite State. Currently, gas stored under this contract must be used in the Lawrence and Springfield Divisions.

The Company has a second short term contract with Consolidated which provides for 2,054,000 MCF of storage and a daily withdrawal of 13,603 MCF. Transportation of this gas is provided on a best-efforts basis by Granite State. This contract expired on October 22, 1982 and is not reflected in the EFSC filing past that date.

The Company has a long-term underground storage contract (STB) with Algonquin which provides for a gross storage volume of 676,960 MCF and a maximum daily withdrawal of 7,522 MCF. Transportation of this gas is provided on a best-efforts basis by Algonquin. This agreement will expire on April 15, 2000, but will continue thereafter unless terminated by either party on twelve months written notice.

The Company has a second short-term storage contract with Consolidated with an expiration date of April 16, 1983. The gross storage volume provided under this agreement is 429,559 MCF with a maximum daily withdrawal of 2,830 MCF. Transportation of this gas if provided or a best-efforts basis by Algonquin. Currently gas from these two Algonquin contracts must be used in the Brockton Division.[30]

The Company is currently negotiating a third long-term storage contract to increase the Company's storage capability and to complement the Boundary Gas Project. The Penn-York Energy Corporation has filed with FERC for authorization to provide storage of 1,894,400 MCF with a maximum daily withdrawal of 17,222 MCF. Granite State has filed an application for a certificate to provide storage and storage-related transportation service. Tennessee Gas Pipeline Company has filed an application for a certificate to provide transportation for this source. These applications are pending before FERC for final action. If for some reason, these certificates are not granted prior to the next

30 DPU Supply Study. Id. at Ch. 2, pg. 7.

heating season, Granite State and Tennessee will be able to provide storage and transportation service to the Company, under temporary certificates granted in July, 1982.[31] This gas will be used in the Springfield and Lawrence Division and will be on a best-efforts basis.

As noted above, transportation of all storage gas is on a best-efforts basis, and therefore, this gas supply is not considered as supply on the coldest days of the winter season.

C. Liquefied Natural Gas (LNG)

1. Supplies

Bay State obtains imported LNG from Distrigas of Massachusetts Corporation (DOMAC) under a contract which expires January 1, 2000. This contract provides for a maximum daily delivery of 10,000 MCF and an annual quantity of 2,610,000 MCF. LNG can be delivered from DOMAC's import terminal at Everett, Massachusetts, to all of the Company's divisions by transport trailers and can be delivered during the heating season (November 1 through March 31) to the Springfield and Lawrence Divisions by pipeline displacement utilizing the facilities of Boston Gas Company and Tennessee Pipeline Company.[32] However, since the transportation of this LNG by pipeline displacement is on a best-efforts basis, this supply is not considered a gas supply source for the coldest days of the winter season. Normally, all of the LNG which is received from DOMAC during the non-heating season (April 1 through October 31) is transported to LNG facilities for storage until the following heating season.

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31 Response to Information Request, October 12, 1982.

32 In Re Boston Gas Co., 8 DOMSC ___, Tables S-6, S-7 (EFSC 82-25, November 22, 1982).

2. Reliability of LNG Supply

Although DOMAC is projecting full contractual deliveries of LNG for the future, Bay State has discounted its DOMAC supplies to 90 percent of full contractual volumes to provide a contingency in the event of disruption. In compliance with Condition 3 of the most recent EFSC Bay State Decision, the Company has listed the reasons why it feels that this level of LNG delivery is appropriate, including recent communications with DOMAC indicating that Sonatrach will continue in the future to deliver at their contractual level; an excess of shipping capacity at the present time; and continued indications that Sonatrach is making great efforts to make LNG a reliable supply.

3. Facilities

The Company has two large LNG facilities and four satellites. In addition, the Company leases LNG storage from Algonquin LNG, Inc.

The largest of the Company's LNG facilities is located in the Springfield Division in Ludlow and consists of a 1,020,000 MCF storage tank, liquefaction equipment capable of liquefying 7500 MCF of natural gas per day, and vaporization equipment with a maximum daily design capacity of 55,000 MCF.

The second major LNG facility is located in Easton, in the Brockton Division, and consists of an 800,000 MCF storage tank and vaporization equipment with a daily capacity of 35,000 MCF per day. LNG in excess of that required to fill the Ludlow tanks can be transported to other LNG facilities for storage.

The Company has two LNG satellites in the Brockton Division. One is located in Marshfield and consists of two LNG storage tanks with a total capacity of 8,000 MCF and a vaporization capacity of 12,000 MCF per day. The other satellite is portable and has a daily vaporization capacity of 3,600 MCF. Due to the portable nature of this facility, it has no accompanying storage and is dependent on the presence of LNG transport for its LNG supply. This unit is completely mobile and may be stationed throughout the Company's service territory.

A third LNG satellite is located in Lawrence (in the Lawrence Division). It consists of five storage tanks with a total capacity of 13,000 MCF and a vaporization capability of 19,000 MCF per day. A fourth LNG satellite is a portable unit normally located in Scituate in the Brockton Division, and has a vaporization capability of 4,000 MCF per day.

The Company has a contract for LNG storage with Algonquin LNG, Inc. This facility is located in Providence, Rhode Island. The contract, with an expiration date of May 31, 1992, provides for 100,450 MCF of storage during the period June 1, 1982 through May 31, 1987, and 117,950 MCF of storage for the balance of the contract period.[33] LNG is delivered to this facility during the non-heating season, April 1 through October 31, from both the DOMAC and the Company's Ludlow LNG facility by transport trailer. Redelivery of this LNG to the Company's Division is done by transport trailer and/or by pipeline displacement to the

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33 DPU Supply Study, Ch. 4, pg. 9.

Brockton Division utilizing the facility of Providence Gas Company and Algonquin. Again, this delivery by pipeline displacement is on a best-efforts basis and is not considered as a supply source on the coldest days of the winter.

The Company's standard operating procedure requires that all LNG facilities be filled prior to November 1 of each year. The storage capacity at the Ludlow and Easton plants is sufficient to meet the supply demands placed on those facilities. However, due to the limited storage capacity of the satellites, these facilities have to be continually resupplied. To accomplish this, the Company owns four LNG transport trailers and rents a fifth. In addition, it is anticipating a contract which would provide for fourteen loads of LNG per day.[34]

D. Propane Air Vapor

1. Supplies

Bay State has several short- and long-term contract for the supply of propane. The Company has a liquid propane supply contract with Petrolane Northeast Gas Service, Inc. which will expire on March 31, 1985 but can be extended unilaterally by Bay State for five years or can be continued on a year-to-year basis by mutual consent of Bay State and Petrolane. The contract provides for 6,000,000 gallons (550,458 MCF) on a firm basis and 4,000,000 gallons (366,972 MCF) on an option basis. Petrolane is responsible for delivery of this propane and is obligated to deliver 14 transport loads per day. One load of LP equals approximately 9000 gallons or 826 MCF.

34 Response to Question No. 28, Information Request No. 3, October 4, 1982.

A second long-term contract is with C.M. Dining, Inc. and provides 282,000 gallons (25,872 MCF) on a firm basis and 188,000 gallons (17,248 MCF). A third long-range contract with Country Gas Distributers, Inc. provide 300,000 gallons (27,523 MCF) on a firm basis and 200,000 gallons (18,349 MCF) on an optional basis. Volumes from these two contracts are delivered during the period November 1 through March 31. These two contracts expire on March 31, 1985, but either or both may be extended unilaterally by Bay State for five years. The delivery of this propane is also the responsibility of Dining and Country gas with both being obligated to deliver two transport loads per day.

The Company's remaining propane contracts are one year contracts which all expired on March 31, 1982 and are shown below. The filing indicates this loss of supply after March, 1982.

Supplier	Firm		Option	
	Gallons	MCF	Gallons	MCF
Commonwealth Propane Company	3,600,000	330,275	2,400,000	220,183
Gas Supply, Inc.	1,200,000	110,092	800,000	73,394
Big Horn, Ltd.	600,000	55,046	400,000	36,697
Maine Gas & Appliance, Incorporated	1,440,000	132,110	960,000	88,073
UPG, Inc.	1,200,000	110,092	800,000	73,394

Since the filing the Company has entered into two short-term contracts which expire on March 31, 1983.[35] These are with Dorchester Sea-3 Products, Incorporated and UPG, Incorporated and provide for firm quantities of 715,596 MCF and 33,046 MCF, respectively. The optional quantities are 477,064 MCF for the Sea-3 contract and 36,697 MCF for the

35 Updated by the November 5, 1982 filing, per EFSC Administrative Bulletin 82-1.

UPG contract.

2. Facilities

The Company has seven liquid propane (LP) air gas plants dispersed throughout its service territory.

Three of these LP air plants are located in the Brockton Division in the towns of Brockton, Taunton and West Medway. The combined storage capacities of these three facilities is 79.6 MMCF, 32.4 MMCF and 20.3 MCF, respectively, and the daily vaporization capacities are 22 MMCF, 12 MMCF and 5 MMCF, respectively. All of these plants can receive transport trailers and rail deliveries.

The Lawrence Division has a single LP air gas plant located in Lawrence with a storage capacity of 24.5 MMCF and a vaporization capability of 22 MMCF. This plant is only capable of receiving transport trailer deliveries.

The remaining three LP air gas plants are located in the Springfield Division in West Springfield, East Longmeadow and Northampton. The storage capacity of these three facilities is 79.3 MMCF, 59.5 MMCF and 24.5 MMCF respectively,and the maximum daily vaporization capacity is 25 MMCF, 13 MMCF and 11 MMCF. All three LP air gas plants are capable of off loading transport trailers, and West Springfield can accomodate rail deliveries.

The Company currently owns four LP trailers and rents a fifth.

E. Synthetic Natural Gas (SNG)

The Company purchases SNG from Algonquin under the SNG-1 rate schedule. The SNG is manufactured at Algonquin's SNG plant in Freetown, Massachusetts and is delivered by Algonquin to the Company's Brockton Division by pipeline.

This contract provides a maximum daily delivery of 18.3 MMCF and an annual quantity of 2766 MMCF. Deliveries of SNG under this contract are confined to the period November 1 through March 31. Bay State has the right to reduce, up to 50 percent, its purchase level each winter season provided the Company notifies Algonquin of its intention by June 20 of the preceding spring. This option has been elected for each of the past two heating seasons, and the Company expects to elect this option for the remaining life of the contract.

For the 1982/83 heating season, the Company nominated to receive fifty percent of the contract amount.

F. Future Supply Sources

Bay State owns 10.27% of the outstanding stock of Boundary Gas, Inc., a corporation which has contracted with TransCanada Pipelines Ltd. for the purchase of 185 MMCF of natural gas per day for a ten-year period. This gas will be imported at Niagara Falls and will be delivered to the service territories of Boundary members by Tennessee.

The firm daily and annual volumes that Bay State will receive from this project are to be 15.5 MMCF and 5657 MMCF, respectively. The Company has recently re-evaluated its expected date of delivery for Boundary and now expects Boundary Gas deliveries to commence on November 1, 1984. Currently, all of the gas to be made available under this arrangement will have to be used in the Lawrence and Springfield Divisions.[36]

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36 We note that Granite State may be substituted as the designated Boundary recipient at some future time. This technical amendment to the agreement would have no effect on the Boundary Project, *per se*. *See* Direct Testimony of James A. Rooney on behalf of Boundary Gas, Inc., FERC Docket Nos. CP81-107, 108, 296, 298 (1982).

The Company is also a participant in the Trans-Niagara project, a project whereby three transmission companies, including Algonquin, have joined together to import 300 MMCF per day from Canada for a 15 year period. The gas will be imported at Niagara Falls. Expected future volumes are uncertain, but the Bay State portion of the project will not exceed 7.5 MMCF per day during the period April 16 through November 15 and 7.1 MMCF during the period November 16 through April 15, and the net annual volume will not exceed 2,681 MMCF. Due to the uncertain nature of these proceedings before the various U.S. and Canadian regulatory agencies, the Company has not included the Trans-Niagara volumes in its supply forecast. However, when the gas from this project does become available, it will be used in the Brockton Division.

V. COMPARISON OF RESOURCES AND REQUIREMENTS

The Bay State Gas Company is separated into three non-contiguous service divisions. This is a result of the incorporation of the Company though the merging of the former Brockton/Taunton Gas Company, the Springfield Gas Light Company, the Northampton Gas Light Company and the Lawrence Gas Company. To fully understand the supply and sendout parameters of the Company, requires, to a large degree, viewing each division's resources and requirements as an independent system. Until now, however, the Council has not required companies like Bay State to submit separate sets of data for each of its divisions. As such, the staff in this case has had a limited amount of disaggregated data upon which to draw conclusions about the Company's ability to meet the separate requirements of each of its divisions. This has mostly consisted of peak day analyses supplied in response to information requests.

In future filings, the Company will be required to supply data that more adequately reflects its divisional realities. It is hereby made an express Condition to the approval of this forecast that Bay State submit appropriate disaggregated data on its three divisions in all future filings. Council staff will prepare, in consultation with Bay State representatives, appropriate forms that Bay State should use in fulfilling this Condition. (See Condition No. 7).

A. Normal Year

Bay State's supply depth and sendout flexibility generates, on an aggregate basis, an ample ability to meet its system requirements in a normal year scenario. Even assuming that the Company's 3%/year growth in aggregate sales does develop, the surplus gas amount over the forecast period ranges from 4.4% to as much as 21.6% (See Table 6).

Disaggregating into heating and non-heating seasons reinforces the above conclusion. During the non-heating season, when demand is low, the Company is able to meet over 90 percent of sendout requirements with pipeline gas (including storage gas). The remainder is met with LNG (6-8 percent over the forecast period) and propane (0-1 percent over the forecast period).

During the heating season the Company relies on a much more diverse mix of supplies to meet firm requirements. During the 1982-1983 heating season, the Company's supply mix breaks down as follows: 77 percent of sendout is pipeline; 8 percent is storage return gas; 12 percent is propane; and 4 percent is LNG. During the 1986-87 heating season, the breakdown is the following: 69 percent of firm sendout is existing pipeline gas; 8 percent is Boundary, 14 percent is storage return gas;

Table 6

Bay State Gas Company

Normal Year Comparisons (MMBTU)[1]

	Firm Sendout[2]	Firm Supplies[3]	% Surplus
1982-83	35,400	40,061	21.6
1983-84	36,342	43,033	18.4
1984-85	37,284	38,908	4.4[4]
1985-86	38,226	43,897	14.8
1986-87	39,169	44,310	13.1

1. From DPU Supply Study, with noted adjustments.
2. Includes off-system sales (at a constant level) and assumes 3%/year growth in firm, on-system sales.
3. Assumes Boundary available at 5793 MMBTU/year beginning Nov. 1, 1984; does not not include spot purchases of natural gas and short-term propane contracts beyond 1983-84 or Bay State Exploration Gas.
4. The principal reason that the 1984-85 surplus shrinks in this Table but not in the DPU Supply Study is that Bay State's DPU Supply Study includes spot purchases as available through October 31, 1984.

and 8 percent is LNG. Table 7 compares normal heating season supply, by source, with firm sendout requirements for the first and last years of the forecast.

B. Design Year

In a design year, several changes occur in the Company's comparison of resources and requirements. Options on additional quantities of liquid propane and LNG can be exercised and interruptible sales can be cut back. Table 8 shows a comparison of annual design firm sendout with annual design firm supplies for the forecast period.

As is obvious from the table, for every year of the Forecast, with the exception of 1984-85, the Company has a supply cushion above its aggregate firm design requirements. The exception, however, merits a word of explanation as this perceived shortfall does not appear in either the Company's EFSC Forecast or the DPU Supply Study.

In an effort to portray an accurate and complete picture of the Company's resources and requirements that is consistent with the Council's policies, the EFSC staff has made several adjustments to Bay State Gas Company's Long-Range Forecast. The 1984-85 supply/sendout comparison, as shown in Table 8, differs from the December, 1981, Forecast in two principal ways. First, the table reflects the Company's present thinking, which the Council perceives as reasonable, that the Boundary Gas volumes will not be available until the 1984-85 heating season. At the time of the filing of the EFSC Forecast, the Company projected full availability of Boundary Gas for the Fall of 1983. This difference results in a loss of 3396 MMBtu in the summer of 1984. The second adjustment is the result of a more complete accounting of

Table 7

Bay State Gas Company

Heating Season Supply and Sendout (MMCF)

	1982-83 Total Available Supply	1986-87 Total Available Supply
EXISTING RESOURCES		
Pipeline		
Algonquin		
F-1	5049(17%)	5049(18%)
ST-1/ST-T	1101(3)	626(2)
WS-1	1092(4)	1092(4)
SNG	2766(9)	2766(10)
Granite State		
CD	9918(34)	9918(35)
Storage	3349(11)	3473(12)
Supplemental		
LNG Storage	2839(10)	3104(11)
Propane	3282(11)	320(1)
Future Supply		
Boundary	-	2304(8)
Total Supply	29306(100%)	28688(100%)
On-System Normal Requirements	21438	23897
Off-System Normal Requirements	2291	2291
Total Normal	23695	26188

Source: Forecast, Table G-22(B); November 5th, 1982 filing, DPU Supply Study.

Table 8

Design Year Comparisons (MMBtu)[1]

	Firm Sendout[2]	Firm Supplies[3]	% Surplus
1982-83	38,782	43,980	13.4
1983-84	39,789	43,899	10.3
1984-85	40,796	39,310	(3.6)
1985-86	41,803	44,290	5.9
1986-87	42,809	44,978	5.1

1. From DPU Supply Study, with noted adjustments.
2. Includes off-system sales (at a constant level) and assumes 3%/year growth in firm, on-system sales.
3. Assumes Boundary available at 5793 MMBtu/year beginning November 1, 1984; does not include spot purchases of natural gas and short-term propane contracts beyond the 1983-84 split-year or Bay State Exploration gas.

off-system sales. (See discussion, supra, at pages 32-35.) These firm contracts are currently projected by the Company to be 4216 MMBtu per design year throughout the forecast period. As discussed earlier in the sendout section of this Decision, these volumes were not included in Bay State's Long-Range Forecast as firm.

Similarly, the 1984-85 shortfall does not appear in the Company's DPU Supply Study. In that document, however, there are different adjustments that are required. Although the Study differed from the Forecast in that the noted volumes of off-system sales were accounted for as firm requirements, the study shared with the December, 1981, Forecast an optimistic projection of Boundary Gas deliverability. As of the time of the Study (August, 1982) the Company was anticipating 1698 MMBtu of Boundary to be available in the summer of 1984. The more significant adjustment to the DPU Supply Study, however, results from the Council's policy of not counting short-term contract supplies as firm for any longer than their contract terms. The Company, in its DPU Supply Study, relies on 3500 MMBtu of spot purchase pipeline gas supplies, the terms of which are "usually of less than one year's duration" (DPU Supply Study, Chapter 4, page 3), that are excluded by the EFSC staff from Table 8. Table 9 shows the relevant figures, both exactly as they were submitted by the Company to the two regulatory bodies and after the EFSC staff's Table 8 adjustments.

Table 9

Bay State Gas Company

1984-85 Design Year Comparisons (MMBtu)

	EFSC Forecast (11/81)[1]	DPU Supply Study (8/82)	Table 8
Firm Sendout	37,909	40,796	40,796
Firm Supplies	42,929	44,595	39,310
% Surplus	13.2	9.2	(3.4)

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1 From Table G-22.

The Council realizes that a history of successive short-term contract renewals, such as Bay State has experienced with several of its pipeline and propane suppliers, offers a certain amount of reliability (possibly, at a reduced cost). However, they are unarguably less secure than long-term contracts.[37] As such, it is hereby made a Condition to this Approval that in its next filing, Bay State provide the Council with sufficient documented assurances that in the event of design conditions in 1984-85 the perceived supply shortfall will not occur (See Condition No. 8).

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37. See discussion in In Re Lowell Gas Co., 7 DOMSC 205, 231-32 (March 15, 1982).

It is noteworthy that the above discussion does not take into account the Company's interruptible sales. As such, it may be prudent to briefly discuss the role that interruptible customers play in the Company's planning process.

The Company has stated that the amount of gas available to be sold to interruptible customers in any non-heating season is dependent upon the "difference between pipeline gas available and the pipeline gas required to meet Bay State's firm requirements, refill underground storage and liquefied to refill LNG storage." (Info. Request No. 3, Q. No. 7). As such, the Company's planned interruptible sales effectively take on a "leftover" status. Table 10 is a compilation of Bay State's DPU Supply Study figures for interruptible sales and shows how the Company plans its interruptible sales potential.

Assuming that for the Company's planning purposes,interruptibles play a pure "leftover" role[38], it would be unfair to critically compare the Company's interruptible sales projections to the staff's Table 8 supply surplus and shortfall estimates. The Company's interruptible customers are simply seen as bearing the risk that the supplies that are viewed by the Council as less than reliable might not materialize. If, e.g., the Company's projected spot purchases of summer pipeline gas do not materialize in the years that show a surplus in Table 8, there will presumably be less gas for the interruptible customers, not less gas in

38 The validity of this assumption, among other concerns is an issue in the DPU's continuing investigations in DPU 555 (See pp. 11 and 72-73) and DPU 19806-B/4240-81, and was conceivably part of the DPU's rationale in ordering the Company to prepare a cost of service study methodology in Bay State's last rate case decision (See DPU 777, p. 59). In light of these investigations and other Council concerns, the Council views this issue as beyond the scope of the instant adjudication.

Table 10

Interruptible Sales[1]

	Supply	Firm Requirements	Interruptible Sales
1982-83 Normal	43,147	35,400	7747
1982-83 Design	44,066	38,782	5284
1983-84 Normal	44,318	36,342	7976
1983-84 Design	45,184	39,789	5395
1984-85 Normal	44,192	37,284	6908
1984-85 Design	44,595	40,796	3799
1985-86 Normal	43,983	38,226	5757
1985-86 Design	44,376	41,803	2573
1986-87 Normal	44,396	39,168	5228
1986-87 Design	45,064	42,809	2255

1 From DPU Supply study, Chap. 6, page 5, unadjusted.

winter storage. Similarly, the Council expects that there would be no sales to interruptible customers in the event that the projected 1984-85 shortfall materializes. The fact that the Company is planning on these larger quantities of interruptible sales does not, therefore, cause the Council concern vis-a-vis whether firm customers' projected needs will be met.

The important concern is to make sure that the Company does not overestimate the amount of gas that is "leftover". One way to do this, of course, is for the Company to ensure that its storage tanks are full at the beginning of each heating season. The Council is satisfied that the Company does, in fact, strive to meet this goal. This is based on staff conversations with Company officials and is evidenced by both the narrative in the DPU Supply Study (see Chapter 4, pages 8, 10, and 11) and by the G-22 Tables in the EFSC Forecast. Table 11 details the Company's storage capacity and inventory levels going into the present 1982-83 heating season.

Table 11

Bay State Gas Company

Storage Utilization(MMBtu)/November 1, 1982[1]

	Net Storage Capacity[2]	Inventory Levels[3]
Algonquin (ST-T)	378.0	378.0
(STB-1)	633.0	633.0
	1011.0	1011.0
Granite State (GSS)	1550.0	1550.0
	1802.7	1802.7
	3352.7	3352.7
Bay State Propane	320.0	320.0
LNG Storage		
Bay State	2021.1	
Algonquin	100.5	
	2121.6	1993.0[4]
	6805.3	6676.1

1. All pipeline storage gas figures are net of fuel gas requirements.
2. From EFSC Forecast, DPU Supply Study and Information Requests.
3. From Bay State's November 5, 1982, filing in compliance with Administrative Bulletin 82-1 (Table G-22).
4. LNG Storage; disaggregated.

C. Peak Day

1. Company Aggregate

The truest test of a gas company's ability to satisfy the requirements of its customers is its capacity to successfully meet its system's peak day needs. 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 product of the maximum rate of firm gas deliveries that a Company is capable of in a single day. The maximum daily rate at which gas can be sent out is in large measure a direct function of the physical limitations of a given system: pipelines, compressors, LNG vaporizers, and propane/air facilities. Facilities that are shared, such as interstate pipelines, also depend on contractual and governmental constraints. Table 12 compares Bay State's projected 1980-81 maximum daily deliverable quantities with its actual peak day sendout for that period, according to supply source.

The Company expects that over the forecast period the only changes to its peak day sendout capability will result from its two Canadian import projects, Boundary Gas and Trans-Niagara. As Table 13 indicates, the Company's peak day capability increases from 366 MMCF/day in 1982-83 to 389 MMCF/day in the last three years of the forecast period.

As Canadian gas imports rise from zero contribution in 1982-83 to supplying 5.9% of Bay State's peak day resources by the end of the forecast period, pipeline gas decreases from 35.8% to 33.7%, propane decreases from 30.1% to 28.3% and LNG reliance is reduced from 34.1% to

Table 12

Bay State Gas Company

Comparison of Resources and Requirements: Peak Day Sendout
(MMCF/Day)

	Planned Usage[1] 1980-81	Actual Usage[2] 1980-81
Pipeline		
Algonquin		
F-1	33	33
WS-1	18	13
SNG-1	15	15
Tennessee		
CD	66	53
Storage	0	7
Non-Pipeline		
Propane	95	64
Vaporized LNG purchase	130	73
LNG Storage	0	5
TOTAL	357	263
Forecast Sendout Projected/Required	251	251
Degree Days - Design/Actual	67	64

1. Table G-23, Fourth Supplement.
2. Table G-23, Second Long-Range Forecast.

Table 13

Bay State Gas Company

Aggregate Peak Day Sendout Capability and Projected Requirements (MMCF)

	1982-83	1983-84	1984-85	1985-86	1986-87
Pipeline					
Algonquin					
F-1	33	33	33	33	33
WS-1	18	18	18	18	18
SNG	14	14	14	14	14
Granite State					
CD	66	66	66	66	66
Non-Pipeline					
Propane	110	110	110	110	110
LNG Storage	125	125	125	125	125
Canadian					
Boundary	0	8	16	16	16
Trans-Niagara	0	0	7	7	7
	366	374	389	389	389
Projected Requirements	283	291	299	306	314
Excess Capacity (MMcf)	83	83	90	83	75
As % of Requirements	29.3	28.5	30.1	27.1	23.9

Sources: Table G-23, November 5, 1982, Ad. Bull. 82-1 filing; DPU Supply Study, Chap. 3, pages 8-9 and Ch. 5, pgs. 24-25.

21.1%. If the maximum daily quantities of pipeline, Canadian and firm storage gas are available and all propane and LNG facilities are operable at maximum design capacity the Company potentially has from 23.9 to 30.1 percent more capacity available than is necessary to meet design day peak loads during the forecast period.

2. Divisional Analysis

The above noted peak day capacity cushions were the result of an analysis that viewed the Company as a whole.

Due to the fact that the Company serves customers in three non-contiguous service areas, review of the Company's design day sendout capability is not complete without further disaggregation. An overall design day capacity surplus does not, in and of itself, insure that each of the Company's divisions will also have an adequate sendout capability. Table 14 compares Bay State's peak day resources and requirements for each of the Company's three divisions in both the 1982-82 and 1986-87 split years. As the following division-specific analysis demonstrates, the Council is also satisfied that each of the Company's three service territories will have sufficient capacity to meet the peak-day requirements of their respective customers.

a. Brockton Division

The Brockton Division of the Company (hereinafter "Brockton") has the largest share of Bay State's peak day sendout needs, projected to require approximately 115 MMCF/peak day during the 1892-83 heating season. Of this amount, 2.6 MMCF/day represents Brockton's share of Bay State's guaranteed firm off-system sales.

To meet these requirements, Brockton relies most heavily on its

Table 14

Bay State Gas Company

Divisional Peak Day Resources and Requirements (MMCF)[1]

	Brockton 1982-83	Brockton 1986-87	Lawrence 1982-83	Lawrence 1986-87	Springfield 1982-83	Springfield 1986-87
Pipeline						
Algonquin						
F-1	33.4	33.4	-	-	-	-
WS-1	18.2	18.2	-	-	-	-
SNG[2]	14.4	14.4	-	-	-	-
Granite State						
CD	-	-	19.3	19.3	46.4	46.4
Non-Pipeline						
Propane	39.2	39.1	21.1	21.1	49.8	49.8
LNG Storage	50.6	50.6	19.2	19.2	55.0	55.0
Canadian						
Boundary	-	-	0	5.6	-	10.2
Trans-Niagara	-	7.1	-	-	-	-
Peak Day Resources	155.8	162.8	59.6	65.2	151.2	161.4
Peak Day Requirements	115.3	128.4	53.9	59.6	113.8	126.1
Excess Capacity (MMCF)	40.5	34.4	5.7	5.6	37.4	35.3
As % of Requirements	35.1	26.8	10.6	9.4	32.9	28.0

1. From DPU Supply Study, Ch. 3, page 8 and Ch. 5, pgs. 24-25.
2. Adjusted to reflect a reduction in the Company's contractual quantities of Algonquin SNG from 18,319 to 14,438 MCF/day (Nov. 5, 1982, Ad. Bull. 82-1, filing.)

contracts with Algonquin Pipeline Company. In fact, Brockton receives all of the Company's Algonquin supplies (including pipeline natural gas (F-1), winter storage (SNG-1) and synthetic naptha-based gas (SNG)), being the only Bay State division located on the Algonquin system. These supplies are supplemented by LNG - vaporized at the Marshfield (12 MMCF/day) and Easton (35 MMCF/day) plants, and by propane - mixed at the Brockton (21.9 MMCF/day), Taunton (12 MMCF/day) and W. Medway (5.3 MMCF/day) plants (See Table 15). Hence, Brockton's supply capability is 35.1% greater than its projected peak requirements for the 1982-83 heating season.

b. Springfield Division

The Springfield Division of the Company (hereinafter "Springfield") runs a close second to Brockton in its share of the Company's total peak day sendout requirements. Of the 113.8 MMCF/day projected in Springfield customers' 1982-83 peak day needs, the Division is projected to serve a guaranteed off-system load of 8.2 MMCF/day. This represents 7.2% of its peak-day requirements, as opposed to Brockton's 2.3% guaranteed off-system peak day load.

Unlike Brockton, the Springfield division's principal supplier is the Granite State Pipeline Company (a Bay State Gas Company subsidiary which, in turn, receives its gas from the Tennessee Gas Pipeline

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39 In the last Bay State Decision and Order, 6 DOMSC 102, EFSC No. 80-13 (1981), the Council approved the addition of two air compressors at the Northampton and Lawrence propane-air plants. These two compressors added 15 MMCF to the systems peak day capability. The total peak day capability in the Lawrence and Springfield Divisions have increased 18 and 4 percent respectively with the addition of these compressors, relieving anticipated peak-day problems in the two divisions.

Table 15

Bay State Gas Company

Brockton Division/1982-83 Peak Day Resources(MMCF/day)[1]

	Maximum Daily Design Capacity	%
Algonquin		
F-1	33.4	
WS-1	18.2	
SNG[2]	14.4	42.4
Sub-Total	66.0	
LNG		
Marshfield	12	
Easton	35	
Portable	3.6	32.5
Sub-Total	50.6	
Propane-Air		
Brockton	21.9	
Taunton	12.0	
W. Medway	5.3	
Sub-Total	39.2	25.1
TOTAL	155.8	100.0

1. Source: Information Request No. 2, Question No. 2; DPU Supply Study, Chapter 3, page 8 and Chapter 5, page 24.

2. Adjusted to reflect a reduction in contractual quantities of Algonquin SNG from 18.319 to 14.438 MMCF/day (Nov. 5, 1982, Ad. Bulle. 82-1 filing).

Table 16

Bay State Gas Company

Springfield Division/1982-83 Peak Day Resources (MMCF/day)

	Maximum Daily Design Capacity	%
Granite State		
CD	46.4	30.7
LNG		
Ludlow	55.0	36.4
Propane-air		
W. Springfield	24.7	
E. Longmeadow	13.4	
Northampton	11.7	
Sub-total	49.8	32.9
TOTAL	151.2	100.0

Sources: Response to Question No. 2, Information Requests, June 1, 1982; DPU Supply Study, Chapter 3, page 8, Chapter 5, page 24.

Company). Granite State supplies Springfield with 46.4 MMCF/day. LNG (55 MMCF/day) and propane (49.9 MMCF/day)[39] serve to supplement the pipeline's maximum daily quantities (See Table 16). Thus, Springfield can supply 32.9% over its 1982-83 peak day requirements

c. Lawrence Division

The smallest of Bay State's three service territories, having approximately a 19% share of Bay State's total 1982-83 projected peak day requirements, is the Lawrence Division (hereinafter "Lawrence"). Lawrence is responsible for satisfying a projected (1982-83) 5.3 MMCF in guaranteed firm off-system contracts on a peak day, representing 9.8% of its 1982-83 divisional peak-day requirements. Lawrence is also a part of the Granite State Pipeline system and receives 32.4 % of its peak day supply under that Company's CD contract. Its supplemental gas facilities consist entirely of one LNG plant and one propane-air plant, both located in the town of Lawrence. The plants have maximum design capabilities of 19 and 21 MMCF/day, respectively. (See Table 17). Overall, Lawrence will have a peak day capacity 5.7% above what it will require in 1982-83.

D. Cold Snap

The Council has defined a, so called, "cold snap" as a prolonged series of days at or near peak conditions, similar to the two-to-three week period experienced during the 1980-1981 heating season. The Company's ability to meet such a "cold snap" is related to both its ability to meet design heating season requirements and its ability to meet peak day sendout requirements. It is similar to design heating season requirements in that the Company must demonstrate that the aggregate resources available to it are adequate to meet such a large

Table 17

Bay State Gas Company

Lawrence Division/1982-83 Peak Day Resources (MMCF/day)[1]

	Maximum Daily Design Capacity	%
Granite State		
CD	19.3	32.4
LNG		
Lawrence	19.2	32.2
Propane-air		
Lawrence	21.1	35.4
	59.6	100.0

Sources: Response to Question No. 2, Information Requests, June 1, 1982; DPU Supply Study, Chapter 3, page 8, Chapter 5, page 24.

sendout. On the other hand, it is similar to peak day sendout in that the Company must show that it has, and can sustain, the capacity to deliver large daily loads.

Viewed simply as a matter of the relationship between peak day sendout capabilities and storage capacity, the Company appears to be well situated for managing a "cold snap". For example, the availability of LNG, which is generally regarded to be the critical "cold snap" supply source, seems sufficient. LNG, if stored at or near capacity levels, could be sent out at the Company's maximum peak day rate (125 MMcf/day) for 15 days.[40]

However, the ability to meet an unexpected "cold snap" at any given time during the heating season depends on a number of factors, including the weather experienced to date, supply management and planning and facility capacities.

The Council recognizes that, for the upcoming heating season, the Company does have both the capacity to meet design peak day sendout requirements and the resources to meet design heating season sendout. The prudent management of these resources by, for example, assuring that LNG inventory levels are at all times sufficient to meet peak shaving needs under remaining design winter conditions, appears feasible. However, the Council is concerned that the Company explain and demonstrate this prudence as to future years. As such it is a Condition to this approval that in future filings the Company should specifically address this concern, and demonstrate both the availability of resources and its sendout capacity to meet such cold snap conditions in each of its divisions.

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40 Algonquin storage is not included as it is only available on a "best efforts" basis.

E. Contingency Planning/Surplus Gas

In the Council's review of the Company's 1979 Third Annual Supplement (EFSC No. 79-13), the Company was ordered to "explain how it plans to address the short- and long-term impacts of an immediate cessation of Algerian LNG deliveries..." (4 DOMSC 49, September 9, 1980). The Company's response, in its 1980 Fourth Annual Supplement, set out a reasonable and acceptable analysis of its ability to meet this contingency by various steps, depending on when in the year the shipments were interrupted. These steps include the shifting of Algonquin pipeline deliveries, the increasing of its liquefaction rate, and the reduction of interruptible sales.

Although the Council, in its most recent Decision and Order on Bay State (EFSC 80-13), again noted concern over the Company's planning for the contingency of a disruption in Algerian LNG supplies, it did not further Condition the Company in this regard. (6 DOMSC 109, June 22, 1981).

In January, 1981, the Company experienced a supply disruption. When the Algerian LNG shipments were halted, the Company was able to fully satisfy both its on-system and off-system customers.[41] The fact that this supply disruption also occurred simultaneously with a severe cold snap[42] further enhances the Council's perception that the Company was capable of adequately responding to a major LNG disruption.

41 See DPU Order No. 555, pages 52-73.
42 See pages 69-71, supra.

The last EFSC Bay State Decision evidences that the Council was more concerned about a different type of contingency, i.e., the possibility of a surplus of gas. Condition No. 5 to EFSC Order No. 80-13[43] ordered the Company to "discuss the economic effects on its existing customers of a possible overestimation of customer requirements resulting in 'surplus gas'" and suggested that the Company quantify various scenarios.

The basis for this concern was evidenced again during this year's review of the Company's Forecast. With the single exception of the 1984-85 design year shortfall,[44] the Company has demonstrated a generous supply and capacity surplus over design and peak requirements in every year of the forecast period. In addition, for the two years that were analyzed in Table 14, i.e., the first and last years of the forecast period, there are capacity surpluses from 9.4 to 35.1% above peak day requirements when the Company's three divisions are separately analyzed.

The Company responded to last year's Condition No. 5 by stating in the Forecast narrative that "the cost of this excess supply is far outweighed by the cost which would be incurred by the general public if Bay State was unable to meet the requirements of its customers in a design year".[45] The Company also explained that it "continually monitors the gas requirements of its customers and based on the results of that program, the Company continually modifies its marketing and gas supply programs".[46] In the staff's first set of Information Requests,

43. See, supra, at page 8.
44. Which is arguably the combined result of a delay in the Company's anticipated Boundary delivery date and the Council's policy on short-term contracts. See, supra, pages 52-56.
45. Long Range Forecast, at page 7.
46. Ibid.

Table 18

Bay State Gas Company

Surplus Over Design Requirements

	Aggregate % Surplus over Design Year Requirements[1]	Brockton % Surplus Over Peak Day Requirements[2]	Springfield % Surplus Over Peak Day Requirements[2]	Lawrence % Surplus Over Peak Day Requirements[2]	Aggregate % Surplus Over Peak Day Requirements[3]
1982-83	13.4	35.1	32.9	10.6	29.3
1983-84	10.3	-	-	-	28.5
1984-85	(3.6)	-	-	-	30.1
1985-86	5.9	-	-	-	27.1
1986-87	5.1	26.8	28	9.4	23.9

1. Table 8.
2. Table 14.
3. Table 13.

the Company was asked whether the above conclusions had been quantified and it responded that they had not (Question No. 4).

Although the Council cannot disagree with the general principle articulated by the Company, there must come a point at which the costs of a particular gas surplus outweigh the benefits associated with the degree of reliability it buys. The Company should have a systematic and reviewable process for evaluating this trade-off. However, such a process has not been demonstrated to the Council. At a time of rapidly changing industry structures, a process that includes subjective judgements based on past experiences may no longer be adequate. Therefore, this Approval is Conditioned on the Company demonstrating in its next filing that it has such a process in place and submitting the quantitative analyses that result from such a process, including the levels of surplus above design and peak requirements that make up the Company's internal reliability standards.

VI. ORDER AND CONDITIONS

The Council hereby APPROVES Bay State Gas Company's Second Long-Range Forecast and ORDERS:

1. That, in the next Supplement, the Company shall address the anticipated effects of natural gas price decontrol on its forecast of sendout. This analysis shall include both projected sendout data for each class, anticipated marketing strategies to ensure both a reliable and least cost supply of gas, and anticipated problems with customer accounts receivable. The Company shall also explicitly address the anticipated impacts upon interruptible and dual-fuel customers and explain how this is incorporated into the forecast.

2. That, in its next filing, the Company address the issue of conservation as it affects total sendout in more detail. The Company is directed to explain and document all underlying data and judgements and the manner by which such data and judgements are incorporated into the forecast. Included in this should be documentation and quantification of the means by which conservation is reflected in forecasted customer use factors.

3. That, in its next filing, the Company provide further documentation of its procedure to monitor potential growth, its policy with respect to new load additions, and its method for deriving customer fuel use profiles and explain how the above are incorporated into its forecast of future requirements.

4. That, in its next filing, the Company provide all historical data and judgements used to estimate historical and forecasted base use, and heating use and average use factors in each customer class and describe the manner by which this data and judgement is incorporated into the forecast.

5. That the Company meet with Council Staff within 90 days of the issuance of the Final Decision, and as many times thereafter as the EFSC staff deems necessary, to discuss the development of an adequate methodology for the forecasting of design year, peak day and customer use factors in future forecast submissions. The Company should be prepared to discuss available data and its use in future forecasts, and

the development of a plan to improve upon the forecast methodology to incorporate concerns addressed supra, including the temperature responsiveness of new and existing loads and the variability of base load and heating increments with temperature.

6. That, in all future filings, the Company include off-system requirements in all pertinent tables and forms, with appropriate designations of which amounts are guaranteed (on-peak), firm and optional.

7. That, in all future filings, the Company submit appropriate disaggregated data on its three divisions. The Council staff will meet with the Company to determine how to best fulfill this Condition.

8. That, in its next filing, the Company provide sufficient documented assurances that in the event of design weather conditions in 1984-85, the Company will not experience a shortfall.

9. That, in future filings, the Company should specifically address the issue of meeting customer requirements over a prolonged series of days at or near peak conditions and demonstrate both the availability of resources and sendout capacity to meet such a cold snap.

10. That, in its next filing, the Company demonstrate that it has in place a systematic and reviewable process for quantitatively evaluating the trade-off between the cost of securing a surplus of gas and capacity above design and peak requirements

and the degree of reliability that such a surplus generates. The Company should submit the analyzes that result form such a process and include a discussion of those levels of surplus above design and peak requirements that make up the Company's internal reliability standards.

Lawrence W. Plitch, Esq.
Hearing Officer

This Decision was approved by a unanimous vote of the Energy Facilities Siting Council on December 6, 1982, by those members and representatives present and voting: Noel Simpson (for Secretary George Kariotis); Richard Pierce (for Secretary Eileen Schell); Dennis Brennan, Esq.; Thomas J. Crowley.

Ineligible to vote: Harit Majmudar

12-30-82

Date

Margaret N. St. Clair, Esq.
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

Haverhill Gas Company First Supplement to the Second Long-Range Forecast of Gas Needs and Requirements	)	EFSC 82-15

Final Decision

Paul T. Gilrain, Esq.
Hearing Officer

Margaret Keane
Staff Economist

January, 1983

I. Introduction

The Council hereby APPROVES conditionally the First Supplement to the Second Long-Range Forecast of Gas Needs and Requirements of the Haverhill Gas Company.

The Haverhill Gas Company serves 29,285 customers in 16 cities and towns in northeastern Essex County. Its annual sales for the year ending December 31, 1981 were 4,522 MMcf, about 2.5% of total sendout in the Commonwealth, making it the 7th largest gas company in the Commonwealth. This represents an increase of 128 MMcf over the previous year's sales.*

The Haverhill Gas Company ("Haverhill" or "the Company") filed its First Supplement to the Second Long-Range Forecast on September 30, 1982. The Council then ordered publication of a notice of public hearing and adjudicatory proceedings in newspapers of general circulation within the service area of the Company. A Pre-hearing Conference and Technical session were scheduled for November 10, 1982. There were no intervenors or interested parties, nor did any come forth during the proceedings.

It was agreed that no formal hearing would be necessary as a sufficient record had been compiled. A desk review was conducted.

II. Previous Conditions

The Council's decision in the review of the Company's Second Long-Range Forecast imposed one condition. It was:

1. That, in its next filing the Company consider customer use data, particularly appliance saturation surveys, generated by

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* Return of Haverhill Gas Company to the Department of Public Utilities for the year ending December 31, 1981, p. 7, p. 43.

those electric utilities whose service territories are coincident to that of Haverhill. The EFSC staff can provide assistance in this regard to help identify the appropriate documents.

III. Methodology

This section discusses the review criteria the Council applies in its review of gas company forecasts, a description of the Company's forecast methodology and the application of the review criteria to the Company's forecast.

The Council employs three criteria in its evaluation of gas company forecasts. A forecast is reviewable if a Company's submittal to the Council contains enough information to allow a full understanding of the Company's methodology. Once this threshold of documentation has been crossed, the Council examines whether a forecast is appropriate, or technically suitable for the utility system at hand. A forecast is further judged reliable if it ensures confidence that the assumptions, judgements and data forecast what is most likely to occur. (See EFSC Rules 69.2 and 66.5 for further clarification of review criteria.)

A. NORMAL YEAR

A "normal" year is defined as a year that is neither warmer nor colder than average. The Company receives a service-territory specific Annual Degree Day Report from Stone & Webster Engineering Corp. Normal Year Effective Degree Days are based on the arithmetic monthly average from the Stone & Webster report. Thus the Company utilizes a normal year consisting of 6933 effective degree days based on a 20 year average.

Sendout is forecast by customer class using a sales equation: Monthly Base Load = Base Factor X Number of Customers X Days in Month.[1]

Base load is subtracted from total load, and monthly heat factors are calculated based on effective degree days.

The Company used this method on a monthly basis and aggregated it annually by class to attain total monthly and annual firm sales. See Figure 1, for example.

To attain total firm sales, unaccounted for use and company use were added to total firm use. Unaccounted for use is estimated as 6% of total firm sales; the total unaccounted for use is allocated monthly in line with the Company's three year average for such use. Company use is also allocated monthly in line with a five year average. The historical averages for both uses are documented in the Company's forecast.

B. <u>DESIGN YEAR</u>

A "design year" is defined as the coldest year for which a Company plans to meet its firm customer requirements. The Company used a design year consisting of 7781 effective degree days ("EDD") based on April 1966 through March 1967 data[2]. The Company states, "We have used a Design Year based on the actual period from April 1966 to March 1967, without alteration; the coldest experienced in 20 years."[3]

Design year sendout was calculated as follows. The Company assumed that base sendout was the same in both normal and design years. As shown on Table DD in the forecast, design EDD were approximately 19% greater than normal in the summer season and 10% greater in the winter

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1 Forecast, p. 7.

2 Stone & Webster Management Consultants, Weather Analysis System, Haverhill Gas Company, "Normal Weather frequency August 1961 - August 1982".

3 Forecast, p. 1.

FIGURE 1

The Company gives the following example:

For January 1982, Residential Heat Class:
Base Use[4] = Base Factor X No. Customers X Days in Month

A. = .086 X 19,394 X 31 = 51,700 Mcf

B. Monthly Heat Use = Monthly Heat factor X Number of Customers X Effective Billing Degree Days[5]
= .0133 X 19,394 X 1,320
= 340,500 Mcf

C. Total Monthly Use = Base Use + Heat Use[6]

Total Month Use = 51,700 + 340,500

= 392,200 Mcf[7]

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4. Base Use or Load is a figure representing non-temperature or non-weather sensitive uses for which a company will supply gas to a customer throughout the year (i.e., gas used for cooking as opposed to space heating and temperature related uses).

5. The word "effective" as used here indicates that the wind chill factor is accounted for in the degree day factor.

6. Heating use is a figure representing those uses which are temperature or weather sensitive (i.e., the amount of gas used for space heating and other temperature sensitive uses).

SOURCE: Forecast, p. 7.

season. The temperature sensitive portion of sendout was increased by these percentages to arrive at the design heating load.

As the variance of unaccounted for gas use is almost a direct function of sendout, Haverhill increased the combined company use and unaccounted for use for each season by the percentage increase of firm class sendout.[7]

C. PEAK DAY

A "peak day" is the coldest day that is likely to occur during a twelve month period. The Company used a peak day of 77 effective degree days which is the maximum peak day experienced in the Haverhill system in the last 20 years. This is an increase from the peak day of 68 EDD used in the Third Supplement and the peak day of 76 EDD used in the Second Long Range Forecast. The Company states, "We will continue to use this figure (77 EDD) as our criterion until a future colder period is experienced."[8]

Peak Day Sendout was calculated by multiplying the January sendout heat factor by the design peak heating requirements of 77 EDD. The resulting product was added to the daily base load for the particular year to yield the maximum expected sendout on the peak day.

D. CUSTOMER USE FACTOR

The Company uses August and September as the base months. Because Haverhill operates on cycle billing, data from August billing records reflects July use and September data reflects August use.

In the Residential General class, the 1981 actual base factor of .053 Mcf/cust/day was judged to be low as a result of extremely hot

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7 Forecast, p. 8a.
8 Forecast, p. 1.

weather and was normalized to .055 Mcf/cust/day.

The 1982 actual heat factor in the residential/general class was .98 Mcf/cust/EDD. The Company attributes this increase to the use of "distress heating." They state, "Customers used their ovens in an attempt to keep warm during the severe cold weather in the January billing cycle." [9]

With respect to the residential heat class, the base use factor is declining;[10] split year base use per customer of 34.5 Mcf in 1979 to 32.4 Mcf in 1980, and forecasted to decline to 31.6 Mcf in 1982. This decline can be attributed to a number of factors. A significant percentage of the base load is water heating; conservation has resulted from the increased use of higher efficiency appliances. Average use/customer in new homes 93 Mcf/year versus 118 Mcf/ year in existing homes. The company attributes this 21.2% differential to better insulation and energy efficient appliances utilized in construction of these new homes.[11] Overall, the Company sees the decline in base factor as attributable to increased efficiency of appliances and a reduction in customer usage, particularly in the fringe months of the heating season. See Table 2.

The Company states that, "We feel that the reduction in base use will bottom out the 1988 without some extraordinary technological changes.[12] They attribute the heat factor decrease to more efficient

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9 Forecast, p. 4.

10 1977 average use per heating customer/year = 136.9 mcf
1980 average use per heating customer/year = 120.1 mcf
Exhibit VI, EFSC 81-15.

11 "Average use per customer" may have declined for reasons other than conservation. For example, in recent years some heating customers were landlords who also provided heat to one or more tenant units. If separately metered units were installed, the average use per household must fall.

12 Forecast, p. 4.

Table 2

Annual Base and Heat Factors

Fiscal Year	Residential General Base	Residential General Heat	Residential Heat Base	Residential Heat Heat
1982	.0510	.00109	.0870	.0137
1983	.0510	.00118	.0860	.0133
1984	.0495	.00129	.0850	.0134
1985	.0490	.00139	.0850	.0132
1986	.0488	.00147	.0830	.0130
1987	.0481	.00158	.0830	.0128

Source: Forecast, p. 6.

construction and heating equipment in new homes, use of wood and coal as supplemental fuels and conservation due to economic conditions.[13] The Company is encouraged to study the effects of wood and coal impact on its sendout.

Base and heat factors in the Commercial and Industrial Sectors are calculated individually for large customers, while the smaller customer projections were calculated from historical data and information from the Company's Marketing Department. The Company forecasts increasing load factors in the commercial/industrial class based on expected load of known new customers.

The Company is well aware of the determinants of use in its service territory, has provided thorough documentation of its assumptions and is to be commended for knowledgeable and thorough calculations of usage factors.

E. CONVERSIONS

In Exhibit 2, the Company demonstrates a thorough knowledge of the sources and extent of new services and conversions. Haverhill provides a breakdown of requests for additional gas by town and by Mcf within town, and then details the amount of load actually added. From August 1981 to August 1982, the Company received 689 requests for additional gas service from existing customers most of these being oil-to-gas conservations; 127 requests to re-activate services; 332 requests for new services; and had 78 carry-overs from fiscal 1981. Out of this total of 1226 requests. 851 installations were made.

The Company projects continuing growth, based on its knowledge of the service territory. While Council staff does not question Haver-

13 Forecast, p. 4.

hill's knowledge of its territory, it does remind the Company of the tremendous uncertainties surrounding the relative prices of natural gas and home heating oil. Condition Number 1 will require the Company to study this issue and to present future customer projections within the context of a market where gas and oil prices are converging.

IV. Application of Review Criteria to Company Forecast

The Company's forecast methodology is clearly presented, thoroughly documented, and all judgements are explained. The Company's in-house 10 year sales forecast was a beneficial addition to the Supplement. The differentiation between sales and sendout data enables the Company to account for differences between billing data and calendar data and to capture monthly variance in the number of customers; these are useful refinements. Haverhill has gone well beyond the requirements of the regulations and presented a thoroughly reviewable forecast. The Company is lauded for its progress and cooperation.

It is the opinion of the Council that the Company's methodology is appropriate for its system. The Company forecasts sendout by customer class and separates heating and base use factors. Such refinements provide a methodology more than suitable for the problems of managing the Haverhill Gas system.

Reliability is greatly enhanced by the sophistication of the Company's base use factors and the Company's knowledge of its service territory. Normalization factors are calculated from actual and normal EDD, serving to inspire confidence in these factors.

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14 The Council staff hereby informs the Company that it expects the G-24 tables to be filled out completely each year, regardless of whether or not any changes have occurred.

V. Supply Contracts and Facilities[14]

A. PIPELINE GAS

Haverhill is a customer of the Tennessee Gas Transmission Company and plans to receive 100% of the total curtailed amount from Tennessee (4100.2 MMcf) on an annual basis with the exception of an estimated 20 MMcf left unused during the winter season.

The Company has two storage contracts of 350 MMcf each with Consolidated Gas Supply Corp and National Gas Fuel Storage, both of which will extend beyond the duration of the forecast period. From November, 1982 on, the NGFS contract is reported as Penn-York Underground Storage Service. In November, 1981 the Company received approval for firm delivery of 4 MMcf/day (3.2 MMcf Consolidated and .8 MMcf Penn-York) of underground storage versus its previous supply of 3.18 MMcf of best efforts delivery. Tennessee will transport gas under both contracts.

B. LIQUEFIED NATURAL GAS

The Company purchases liquefied natural gas (hereinafter LNG) from Distrigas of Massachusetts under a contract that extends until 1998. The Company expects less than the contract quantities of 290 MMcf to be delivered, based on historical delivery of 80% of contracted supplies. The Company also has a contract for the purchase of LNG from Bay State Gas Company which runs through 1991, providing for both firm and optional amounts, i.e., 50 MMcf/yr. +25 MMcf if needed for the split year. The purchase of the optional amounts is determined by Haverhill based on its need.

The Company's North Avenue LNG plant has storage capacity of 400 MMcf and maximum daily design sendout capacity of 20 MMcf.

C. PROPANE

The Company expects to send out only a small amount of propane in the heating season. The Company has an agreement with C.M. Dining for the purchase of a minimum of 27,000 Mcf equivalent and a maximum 90,000 Mcf equivalent of propane, which will be shipped by rail. It owns propane storage (43.9 MMcf) and vaporization (8 MMcf/day) facilities in Haverhill.

VI. Comparison of Resources to Requirements

A. NORMAL YEAR

The Company expects to meet total sendout requirements during the forecast period under normal weather conditions as illustrated on Table G-22 of the Forecast. Pipeline gas from Tennessee is expected to provide 96% of the non-heating season load and approximately 82% of the heating season load. LNG provides approximately 4% of the non-heating season load and 8% of the heating season load. Propane is expected to be less than 1% of heating load. It is anticipated that Boundary Gas will provide 8% of heating supply.[15]

In the event that the Boundary Gas is late or cancelled, the Company would:

"1. Reduce the acceptance of new load until other firm supply commitments are in place.

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15 On December 19, 1980, Boundary Gas, Inc. applied to the ERA for authority to import a total of 185,000 Mcf per day of Canadian natural gas for 10 years. Boundary is composed of thirteen natural gas distribution companies and one regional Transmission Company. The gas will be transported by the Tennessee Gas Pipeline Co. Twenty-nine percent of the gas will be distributed in New England. In Massachusetts, Bay State Gas will receive 19 MMcf/day; Boston Gas 13.9 MMcf/day; Haverhill Gas 3.2 MMcf/day; Berkshire Gas 2.1 MMcf/day; Fitchburg Gas 1.05 MMcf/day. Haverhill expects this supply to be available in November, 1984.

2. Curtail all non firm sales.

3. Temporary spot purchases of propane and/or LNG at reasonable prices."[16]

B. DESIGN YEAR

The record indicates that the Company will have sufficient supply to meet the additional requirements expected to occur in a design year by utilizing gas, LNG and propane in storage. As exhibited in the Company's G-22 tables, the Company's total available supply is greater than that necessary to meet total design firm sendout. As noted previously, the Company's design year of 7781 EDD is an increase from the past figure of 7362 EDD.

C. PEAK DAY

The record indicates that Haverhill will have more than adequate resources to meet forecasted Peak Day Sendout requirements during the forecast period. The Company forecast lists 49 MMcf available to meet peak day requirements of 41 MMcf in 1982/83. If the maximum daily quantity of pipeline gas and firm storage gas is available and the propane air and LNG facilities are operable at maximum daily capacity, the Company can sendout some 15-25% more gas than is necessary to meet the peak day load at various points in the forecast period. It is also to be remembered that Haverhill has an unusually high peak day of 77 effective degree days.

D. COLD SNAP

A "cold snap" is a series of continguous peak days, such as the two-to-three week period experienced during the winter 1980-81. Such periods represent particular planning problems for gas utilties

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16 Forecast, p. 9.

different from the problems of meeting needs on one extremely cold peak day, or meeting the needs of an entire heating season.

The Company has, as previously mentioned, significantly more resources available than necesary to meet its peak day requirements Assuming Distrigas LNG were used strictly for peak day requirements, at the maximum daily quantity of 20 MMcf/day, the Company could meet 14.5 consecutive peak days. However, given Haverhill's resources, use of the full 20 MMcf/day of LNG is not required, thereby extending available LNG peak shaving supplies considerably further.

Additional evidence of the Company's ability to meet a cold snap can be seen in looking at its April 30 inventory levels. The 1981-82 heating season consisted of 5370 degree days as opposed to 5316 DD for the previous season and the 30 year normal figure of 5026 DD. Even with the severe winter and the unexpected blizzard in early April, the Company had 188.3 MMcf in underground storage, 211.7 MMcf in LNG storage and 30.8 MMcf of propane remaining, which represents approximately 14 more design days of peak supplies.

VII. Order

Given the foregoing consideration and comments, it is now ORDERED that the Second Long-Range Forecast submitted by Haverhill Gas Company be APPROVED subject to the following condition:

1. That, in the next Supplement, the Company shall address the anticipated effects of natural gas price decontrol on its forecast of sendout, particularly on oil-gas conversions in the residential sector. This analysis shall include both projected sendout data for each class, anticipated marketing

strategies to ensure both a reliable and least cost supply of gas, and anticipated problems with accounts receivable. The Company shall also address the anticipated impacts upon interruptible and dual-fuel customers and explain how this is incorporated into the forecast.

Paul T. Gilrain / CBMcM

Paul T. Gilrain, Esq.
General Counsel

and

Charles B. McMillan

Charles B. McMillan
Executive Secretary

Dated at Boston this 16th day of January, 1983.

Unanimously approved by all Council members present and voting at the January 24, 1983 Council Meeting.

February 19, 1983
Date

Sharon M. Pollard

Sharon M. Pollard
Chairperson, EFSC

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 a Second Long-Range Forecast of Electric Power Needs and Requirements	EFSC No. 82-4

FINAL DECISION

Paul T. Gilrain, Esq.
Hearing Officer

Charles B. McMillan
Executive Secretary

On the Decision

James Coyne, Lead Economist
Susan Fallows, Staff Economist

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I. BACKGROUND AND PROCEDURAL HISTORY

A. A Description of the Companies

The Cambridge Electric Light (Cambridge), Commonwealth Electric (Commonwealth), and Canal Electric (Canal) Companies are subsidiaries of the Commonwealth Energy System (COM/Energy). The three electric companies are collectively referenced as COM/Electric.[1]

Cambridge Electric engages in the production, sale, and distribution of electricity to approximately 39,000 retail customers in the city of Cambridge, and provides electricity at wholesale to the town of Belmont. Population in these two communities is approximately 121,000. Combined sales plus line losses in 1981 totaled 983,298 MWH, with a summer peak of 199 MW. In addition, Cambridge sells steam from its electric generating plants to an affiliated company, COM/Energy Steam Company.[2]

Commonwealth Electric serves approximately 224,000 retail customers in forty communities located in the greater Plymouth, New Bedford, Cape Cod and Martha's Vineyard areas. Year-round population is approximately 440,000, with summer totals being considerably higher. The Company engages in generation, distribution, transmission and sales of electricity which totaled 2,616,910 MWH in 1981. The winter peak was 460 MW.[3]

Total sales (including line losses) for both Cambridge and Commonwealth amounted to 3,600,208 MWH in 1981, which represented 9.4% of total electricity sales within the state. The combined coincident peak in 1981 was 621 MW.[4]

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1 The Companies were formerly "The NEGEA Service Corporation." As of March 1, 1981, they formed as the COM/Electric operating companies of COM/Energy.

2 COM/Electric 1982 Long Range Forecast filed with EFSC, p. 1.1.1, p. 1.2.70, and 1.2.71.

3. Ibid., p. 1.1.2 and p. 1.4.134.

4. Ibid., p. 1.5.11.

Canal is engaged in the generation and selling of output from the generating units located on the Cape Cod Canal in Sandwich, Mass. Canal Unit No. 1 is a 568 MW oil-burning base-loaded unit. Unit No. 2 is a 584 MW oil-fueled cycling unit. Canal sells the output of Unit No. 1 to five utilities, including Cambridge and Commonwealth. Ownership of Unit No. 2 is evenly divided between Canal and Montaup Electric Company, an unaffiliated company. Canal's other major assets are the systems' entitlements in Seabrook Units 1 and 2, amounting to 81 MW or 3.52% of each unit.

The Companies file separate long-range demand forecasts for the two retail companies, in addition to estimates of their combined (coincident) peak demands.

B. <u>History of the Proceedings</u>

On April 1, 1982 the Cambridge Electric, Canal Electric, and Commonwealth Electric Companies filed their joint Second Long-Range Forecast of Electric Power Needs and Requirements (hereafter, Forecast). Publication and posting of the notice of adjudicatory proceedings on this forecast was completed, and a pre-hearing conference was held at the EFSC offices on June 15, 1982. No intervenors were present, and no new facilities were proposed.

Commonwealth's proposed use of herbicides on its newly constructed Dennis-Orleans transmission line was discussed extensively at that time. Spraying of the 9.6-mile stretch between Dennis and Orleans was allowed by the Council in its approval for the construction of the line (See EFSC 79-4B). This past summer Commonwealth, in accordance with state law, sent letters to all affected towns notifying them of its intent to spray. These letters triggered six towns to pass health regulations restricting or prohibiting herbicide use on the Commonwealth rights-of-way. The Company has not challenged these regulations, but instead is seeking a coordinated response from the five state agencies with jurisdiction.

The forecast-review proceedings commenced without the need for formal hearings. Council staff's initial discovery questions were sent to the Companies on September 28, 1982. On October 5th, technical staff for the Council met with staff from the Companies to clarify the scope and direction of discovery. A revised discovery was sent to the Companies on October 12th and the Companies were ordered to respond by November 10.

The Companies responded in a timely manner. On December 22nd, Council staff again met with the Companies staff for an in-depth technical session on Commonwealth's demand and system supply issues. A subsequent session was held on January 6th, 1983, to discuss Cambridge's demand issues.

The Companies' cooperation with the Council in these proceedings has been exceptional. During both technical sessions, the Companies have provided Council staff with a level of understanding in review that is difficult to achieve - and certainly more resource consuming - than usually occurs in a more formal hearings environment.

C. <u>Overview of the Decision</u>

The Decision is organized into five major sections dealing with the Companies': (1) previous demand forecasts; (2) current Cambridge and Commonwealth forecasts; (3) Energy Management Plan; (4) System Supply Plan; (5) and a detailed analysis of the Commonwealth demand model. The following is a decision overview.

The Companies filed their First Forecast in 1976, and Supplements to the forecast in 1977, 1978, and 1979. Each of these forecasts and the Council's Decisions are highlighted in the introductory demand section, and compared to the Companies' Second Forecast, the subject of this Decision.

The Cambridge and Commonwealth demand forecasts are then analyzed. The Decision treats these forecasts as separate entities due to the fact that Commonwealth has adopted the NEPOOL model, while Cambridge forecasts with an independent methodology. Commonwealth, in adopting the NEPOOL model, has made a major commitment to building a methodology that would satisfy the Council's standards of reviewability, appropriateness, and reliability. The model is a large, detailed, and data intensive approach to demand forecasting. Given the complexity of the model and it being Commonwealth's first presentation of this methodology, the Council has examined its use in great depth. (A general overview is presented along with our analysis of the Cambridge methodology, and a more detailed analysis of the model is presented in the concluding section of the Decision.) This has occurred partly at the expense of a less detailed review of the Cambridge methodology. It is expected that Cambridge will receive more in-depth attention with the Companies' next filing.

The demand analyses are followed by a review of the Companies' fledgling Energy Management Plan.

The supply analysis treats COM/Electric's existing, planned, and possible new sources of supply in contrast to its projected system demand.

The major issues treated in the Decision are Commonwealth's adaptation of the NEPOOL model, and the systems' projected capacity shortfalls and continued heavy reliance on oil.

Throughout the body of the Decision the Council renders a critical review of the Companies' demand and supply forecasts. The serious and complex nature of the task often leads to focusing solely on the remaining problem areas and overlooking the Companies' accomplishments. We therefore acknowledge at the outset that the Companies have made tremendous strides since their last filing, particularly in their demand forecasting capabilities.

II. ANALYSIS OF THE DEMAND FORECAST

A. A Comparison of the Previous and Present Demand Forecasts

Cambridge Electric and Commonwealth Electric have established before the Council a seven-year track record of demand forecasting which has been one of mixed reviews. Since the submission of the First Forecast in 1976, the Companies have adopted a largely new demand methodology which is the focus of the present analysis. Prior to this analysis, however, a review of the Companies' developing demand forecasting methodologies will help to place the present forecast in its proper perspective.

1. First Forecast - 1976

Cambridge and Commonwealth (formerly New Bedford Gas and Edison Light) presented their first joint forecast for Council review in 1976. The foundation of the demand methodology was the survey-interview technique. The components of the residential forecast were derived almost exclusively from interviews with bankers, developers, real estate concerns, and various other public and private officials. Residential sales were predicted for customers with and without electric heat based on assumed electric heat penetration rates. The Companies assumed that conservation effects had largely run their course, and a return to increasing levels of average use per customer. Forecasts for numbers of dwellings and occupants per dwelling were also generated. For Cambridge it was assumed that the number of customers would remain constant, but average use would increase.

The commercial forecasts were based on a similar interview methodology for the Cambridge area, and on a fixed ratio of commercial-to-residential sales for the Commonwealth service area. The industrial forecast was derived from interviews with company executives whose firms represented 81% of industrial electric sales. The remaining smaller companies were assumed to follow the predictions of those interviewed. Each industrial customer, in essence, predicted its own ten-year energy and peakload forecast, which the Companies then aggregated and reported by Standard Industrial Classification (SIC).

Total electricity sales were predicted to grow at a compound annual rate of 4.4%, and peak demand at 5.2%.

The Council approved the First Forecast subject to the expectation that future filings would consider the effects on average use of appliance efficiency and saturation, conservation, and price.

2. First Supplement - 1977

The Companies employed the same demand methodology in the First Supplement. Energy was forecast to grow at a compound annual rate of 5.6%, with peak demand rising at 5.3%. Because the Council did not complete its review of the First Forecast until 6 months after the completion of the supplement, the Council approved the First Supplement and merely reiterated its prior concerns.

3. Second Supplement - 1978

The Companies' Second Supplement incorporated demand methodologies that were basically the same as those in prior forecasts. The only significant departure was to abandon the practice of basing the forecast of the Commonwealth service area's commercial sales on a fixed percentage of residential sales. The new method employed an interview technique analagous to that used for other sectors. The Companies responded to the Council's concerns expressed in its First Forecast Decision, but did not explicitly address the effects of price, appliance efficiency and saturation, conservation, or electric heat penetration. The Companies noted that these factors were emphasized during the interview process. The Companies did, however, expressed an interest in applying the NEPOOL model to their service areas and hoped that such an approach would enhance the Companies' quantitative capabilities. The Companies also reported that an appliance saturation survey would be undertaken for the Commonwealth service area.

In the 1978 forecast, energy and peak were predicted to grow at annual compound rates of 4.1% and 4.6% respectively.

The Council approved this forecast, subject to four conditions which focused on the Companies' provision of systematic documentation and empirical justification for assumptions in future forecasts. Reviewability of the forecast was a fundamental concern of the Council's at this time. See 3 DOMSC 37 (1978), at 41.

4. Third Supplement - 1979

The Third Supplement -- the most recent of the Companies' forecasts reviewed until the present review -- was rejected by the Council in May 1981. The Companies presented a demand methodology which was essentially unchanged from previous forecasts and was therefore deemed unacceptable by the Council.

In its decision, the Council found "that the demand forecast presented by NEGEA in its third supplement is based on seriously deficient statistical projection methods. The methodology has at its heart the survey-interview technique which, as it is designed and implemented, is inherently subjective and burdensome to review, and inappropriate to the nature and size of the Companies' service area...." 6 DOMSC 1 (1981), at 7. Specific problems were outlined on a sector-by-sector basis.

The residential methodology was found to rely on an unsystematic process of interviews with officials of varying levels of energy expertise in each town. No standard questionnaires were used, and the quality and accuracy of the data obtained were questioned. Without residential end use data, the effects of conservation, price and appliance efficiency improvements could not be adequately quantified.

The commercial forecast methodology, based on known load additions for early forecast years and extrapolation of historical data for later years, was criticized for its reliance on a non-comprehensive interview process, the inability to demonstrate causal relationships in historical trends, and an over-reliance on judgement without empirical justification.

The industrial forecast had a short-term component, based on interviews with the largest industrial customers, and a long-term component, based on the NEPOOL industrial forecast for Massachusetts. The Council again found this framework to be overreliant on an unsystematic interview process and company judgements for its short-term component. The longer-term component was questioned for its reliance on a NEPOOL forecast that was not demonstrated to be representative of the Companies' service area.

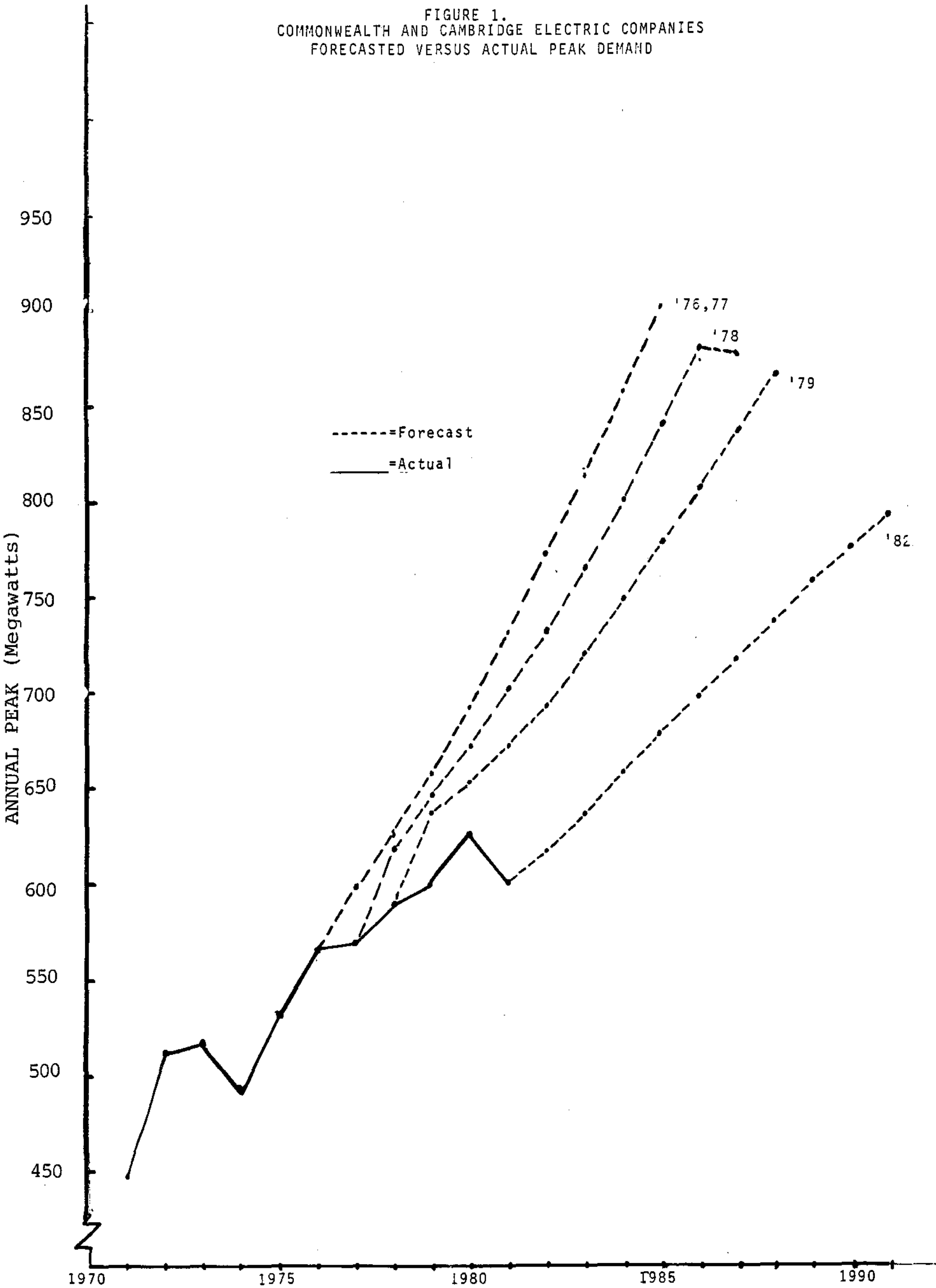
In rendering its decision, the Council issued three conditions pertaining to the demand side of future filings: The conditions laid out specific standards for the gathering of interview data; they emphasized that the Council would no longer accept demand projections primarily based on the survey-interview technique and lacking the quantification of price, conservation, appliance efficiency improvements, changing economic conditions, load management, and other key determinants; and indicated that future demand forecasting methodologies must be supported by a rationale for their use. The Companies' compliance with these conditions is discussed in the following sections, along with the analysis of the forecasting methodologies.

5. Second Forecast - 1982

The Second Forecast marks a significant departure from past methodologies used to forecast demand, particularly for the Commonwealth service area. The Companies have adapted the NEPOOL end-use model for the Commonwealth service area, and have relied upon a discrete-load-addition/econometric methodology for the Cambridge area. These methodologies are analyzed in detail in following sections.

The present forecast calls for system-wide energy growth at 2.7% and peak growth at 2.9% over the next ten years. Figure 1 shows that forecasts of future demand levels have dropped significantly since the Companies' first Forecast. Much of this drop can be attributed to the Companies greater experience with post-embargo consumption behavior, which has indicated a far greater conservation response than previously thought possible.

FIGURE 1.
COMMONWEALTH AND CAMBRIDGE ELECTRIC COMPANIES
FORECASTED VERSUS ACTUAL PEAK DEMAND



B. The Cambridge Demand Forecast

1. General Methodological Considerations

The uniqueness of the Cambridge service area is well known. Its residential population shows little fluctuation over time. Two major universities, MIT and Harvard, account for more than 20% of total electric sales; and development occurs mostly in the form of replacement, rehabilitation, and conversion.[5] For these reasons the Company has opted for an entirely different forecast methodology than that used for the larger, more diverse Commonwealth service area. The Cambridge forecast has been produced using a combination of surveys, econometric modeling, and historical extrapolation. In terms of relative magnitude, Cambridge accounted for 29% of total system sales in 1981.[6]

The Council, in its last decision on these Companies, established three conditions relating to the Companies' future demand methodologies.[7] All three conditions are applicable to the current Cambridge methods, and are addressed in this section. (The new Commonwealth end-use methodology fully satisfies, and goes beyond the applicability of two of the three conditions which address the use of survey-interview methods. The remaining condition, which directs the Companies to present supporting evidence for the selection of its forecasting methods, is addressed for Commonwealth, infra.)

Table 1 presents a general description of the Cambridge demand methodology. The individual components of the forecast are discussed in greater detail in subsequent subsections.

5 Forecast, p. 1.2.3.
6. Forecast, p. 1.1.1 and 2, includes sales to Belmont.
7 See: 6 DOMSC, 30.

Table 1

Cambridge Demand Forecast and Methodology

Projected Avg. Annual Growth (1982-1991)	% of 1981[1] Sales	Method
0.0%	11.2%	- Residential Forecast - both sales and the number of customers assumed constant over the forecast period.
2.8%	62.1%	- Commercial Forecast - based on "known load additions" in conjunction with an econometric baseline forecast.
-.06%	16.2%	- Industrial Forecast - based on customer interviews for short-run component, and time trend for long-run component.
1.5%	9.5%	- Sales to Belmont - based upon Belmont Municipal Light Department's own projections.

1 Calculated from Tables E-2 - E-8, Forecast, pp. 1.2.63-1.2.70.

The Council, having reviewed the Cambridge methodologies, has found that the Company has satisfied in word, or intent, the thrust of the three demand-side conditions.

2. The Residential Forecast Methodology

"Residential electricity sales over the period, 1982-1991, were modeled assuming no growth either in the number of customers or in average energy use by households."[8] The best way to assess the validity of this assumption is to have a look at the data. Table 2 shows historic and projected residential energy use in Cambridge.

We agree with the Company's conclusion that the residential data exhibits a fairly stable long-term pattern. When normalized for weather, the pattern may be even more stable. The Company notes that "we do not expect to see either significant increases in the saturations of major appliances or measurable improvement in energy performance of buildings because 75% of the households in Cambridge are renters."[9] The number of residential customers in Cambridge has also been stable, with a mean of 32,961 and a standard deviation of 195 (0.6% of the mean).[10]

Customers with electric space heating account for only 1% of Cambridge residential load.[11] Presumably, the majority of the load comes from water heating, air-conditioning, refrigerators and ranges.

Given the evidence, we do not fault the Company for its simplistic projection method. The Council does, however, see the need for further

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8. Forecast, p. 1.2.21.
9 Forecast, p. 1.2.21.
10 Ibid.
11 Ibid.

Table 2

Cambridge Historic and Projected Residential[1]
Electricity Sales and Number of Customers

	Year	Sales (mill. KWH)	Number of Customers (thousands)
Actual			
	1971	99.4	32.8
	1972	100.8	32.9
	1973	106.0	32.9
	1974	99.2	32.8
	1975	101.3	32.8
	1976	102.1	32.9
	1977	101.7	32.8
	1978	103.0	33.0
	1979	104.9	33.0
	1980	104.6	33.1
	1981	105.3	33.7
Forecast			
	1982	105.6	33.9
	1983	105.6	33.9
	1984	105.6	33.9
	1985	105.6	33.9
	1986	105.6	33.9
	1987	105.6	33.9
	1988	105.6	33.9
	1989	105.6	33.9
	1990	105.6	33.9
	1991	105.6	33.9

1 Forecast, Table E-11, p. 1.2.71.

data collection. The assumed constant forecast may be adequate for projecting annual kwh sales, but it lends no information on the makeup of the load. In its "Further Areas for Forecast Development" section for Cambridge, the Company has indicated two goals which we wholeheartedly support and urge the Company to act upon. These are:

> "To provide an adequate framework for comprehensive evaluations of the market feasibility and potential impacts of promising conservation and load management strategies..."
>
> and to:
>
> "Extend the Commonwealth Appliance Saturation Survey to Cambridge..."[12]

Considering the capacity shortfalls the COM/Electric system may experience over the forecast period, (as discussed in the supply analysis) the Council feels strongly that Cambridge should be assessing its load management potential in the immediate future. An appliance saturation survey is a logical and important first step in this direction. A survey should indicate the magnitude of potential for load shifting or load reduction from programs such as controlled water heaters and cycling air-conditioners.

3. The Commercial Forecast Methodology

The Commercial sector is the largest, most diverse, and most rapidly growing component of Cambridge's service area. Growth tends to occur in the form of new or increased large load increments due to development or redevelopment.[13] For this reason the Company has opted for a methodology which incorporates a baseline econometric forecast (to

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12 Ibid., p. 1.2.29.
13 See Company Exhibit CCIM-3.

model existing customers) with its knowledge of new or increased loads. Understanding the difficulty associated with deterministically modeling this type of "step growth," we accept this method in principle, but the Council finds certain elements of the procedure problematical.

The Company forms its baseline forecast with a regression equation of the logarythmic form:[14]

$$C_{kwh} = a + b\ MASS_{kwh}$$

where

C_{kwh} = Cambridge Commercial Sales

$MASS_{kwh}$ = Massachusetts Commercial Sales

The Company is able to explain 83% of the variation in historical Cambridge commercial sales with this equation.[15]

The Council sees three separate problems with this method. First, the equation does not account for price, employment levels, or other indicators of energy use in its service area. The equation's predictive ability hinges on the stability in the relationships among the forces that drive Massachusetts' and Cambridge's energy consumption patterns. To the extent that Cambridge prices or employment levels deviate from the state's, the equation's predictive power diminishes.

Secondly, the Massachusetts forecast relied upon to drive the Cambridge forecast originates from NEPOOL. The reliability of the NEPOOL commercial data base is brought under serious question in the Commonwealth analysis which follows. The Council has outlined

14 Forecast, p. 1.2.13.
15 Forecast, p. 1.2.18.

suggestions for ways Commonwealth could improve the model, but we do not exercise the same jurisdiction over NEPOOL.[16]

Finally, the NEPOOL state forecast (or any other) incorporates, explicitly or implicitly, the addition of new loads. The Cambridge methodology involves the explicit addition of new loads. The Company has attempted to alleviate the effects of double counting by only including a portion of the expected new load (60%). The Company, however, has not adequately supported the use of this ratio.[17]

For these reasons, the Council finds unacceptable the use of this baseline forecast and its interaction with the explicit load additions. The Company should establish a new method which addresses these problems.

The explicit load additions to the baseline forecast, in and of themselves, pose no problems for the Council. In fact, the Company has demonstrated an in-depth knowledge of its service area's ongoing commercial development. We urge the company not only to stay on the forefront of predicting these loads, but also to influence how these customers distribute their loads.

4. The Industrial Forecast Methodology

The industrial forecast is founded on a short-run component, based on surveys, and a long-run component, based on a time trend.

The Company sent surveys to 24 of its largest commercial and industrial customers in 1982. Of these, the fifteen industrial customers that responded formed the direct basis for projecting

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16 The Council expressed the same concerns in its last decision relating to the Companies use of the NEPOOL industrial forecast. See 6 DOMSC 1, at 20.

17 See Response to Staff Information Request CCOM-2.

industrial sales over the 1982-1986 period.[18] The Company states that the largest 25 industrial customers represent an average of 96.4% of its total industrial sales.[19] Through the course of discovery it was indicated that only 15 were used, so it is not certain what percentage of sales is represented. Presumably they represent at least a majority.

The historic sales to these large customers were regressed against the class as a whole to determine the relationship. While this method does not explicitly account for price and macro-economic effects, the underlying survey and the small share of industrial sales predicted with the regression do not raise the same degree of concern expressed over the commercial regression analysis. The equation performed well (explaining 93% of the variation), and the Company projected total industrial sales on this basis over the short-term. Cambridge projected the later forecast years (1987-1991) assuming that the 1986 forecast would hold constant. The overall class forecast shows a slight decline over the forecast period due to a projected drop in the first five years.

For the present, the Council accepts this use of customer surveys for the industrial sector. We are pleased to see that the surveys were administered in a standardized manner which eliminates the concerns over interview bias discussed in past decisions. The Company should, however, be precise in reporting the numbers of customers used in the forecasts and the estimation of supporting equations. Lastly, the Company should monitor <u>and report</u> the accuracy of each customer's predictions in subsequent filings to establish the reliability of this

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18 See COM/Electric response to Staff Information Request CCIM-7.
19 Forecast, p. 1.2.10.

method through a performance record.

5. Belmont Municipal Light Department

The Town of Belmont is an all-requirements customer of Cambridge, accounting for 9.5% of its total sales in 1981.[20] In this filing, Belmont provided Cambridge with its own energy forecast. Belmont, however, is a member of MMWEC. As such, MMWEC will prepare forecasts for Belmont that the Council will review with all other MMWEC forecasts. We recognize that the MMWEC forecast was not available to Cambridge at the time of this filing, but we urge the Company to consider this forecast in its future filings.[21] The current MMWEC forecast projects Belmont's energy demand to grow at 0.8% annually, as opposed to the 1.5% provided to Cambridge by the Light Department.[22] The Company has indicated its awareness of this situation, and supplied the Council with both forecasts when they were available.[23]

6. Peak Demand Forecast Methodology

Annual peak demands are forecast by applying the historic mean load factor (over 1970-1981) of .578 to the annual energy forecasts. Peak demands are projected to grow by 1.6% per year, and continue to occur in the summer.

C. The Commonwealth Demand Forecast

The demand forecasting methodology adopted for the Commonwealth service area is derived from the NEPOOL long-range forecasting model. The Companies have adapted the NEPOOL model to the Commonwealth service area with the consulting assistance of Battelle-Columbus Laboratories,

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20 Forecast, p. 1.2.27.
21 See COM/Electric Response to Staff Information Request CB-1.
22 Ibid.
23 Ibid.

the original developer of the NEPOOL model. Commonwealth began to experiment with the model as early as 1977, but it was not until the Council's May 1981 decision which rejected the Companies' methodology that the Companies worked to produce an operative version of the model.

Due to the fact that Commonwealth has essentially adopted the NEPOOL model with service area adjustments as the core of its demand methodology, the Companies have a burden to demonstrate that both the structure of the NEPOOL model and the data used to run it are appropriate for the Commonwealth service area. This point was stressed in Condition 3 of the Council's last decision.[24]

Commonwealth has addressed Condition 3 by accompanying its filing with the submission of the Stone and Webster (S&W) report, "Load Forecasting Management Plan, Commonwealth Electric, Final Report, Feb. 1982." The Company engaged S&W to "review the selection of the NEPOOL model as the basis for the forecast methodology" as well as to review its adaptation of the model and the Companies' overall forecasting capabilities and requirements.[25] This report has aided the Council in its review of the model and the Council commends the Company for providing an independent assessment of the methodology. As the following assessment of Commonwealth's methodology will indicate, the Council has concurred with the S&W recommendations in several areas.

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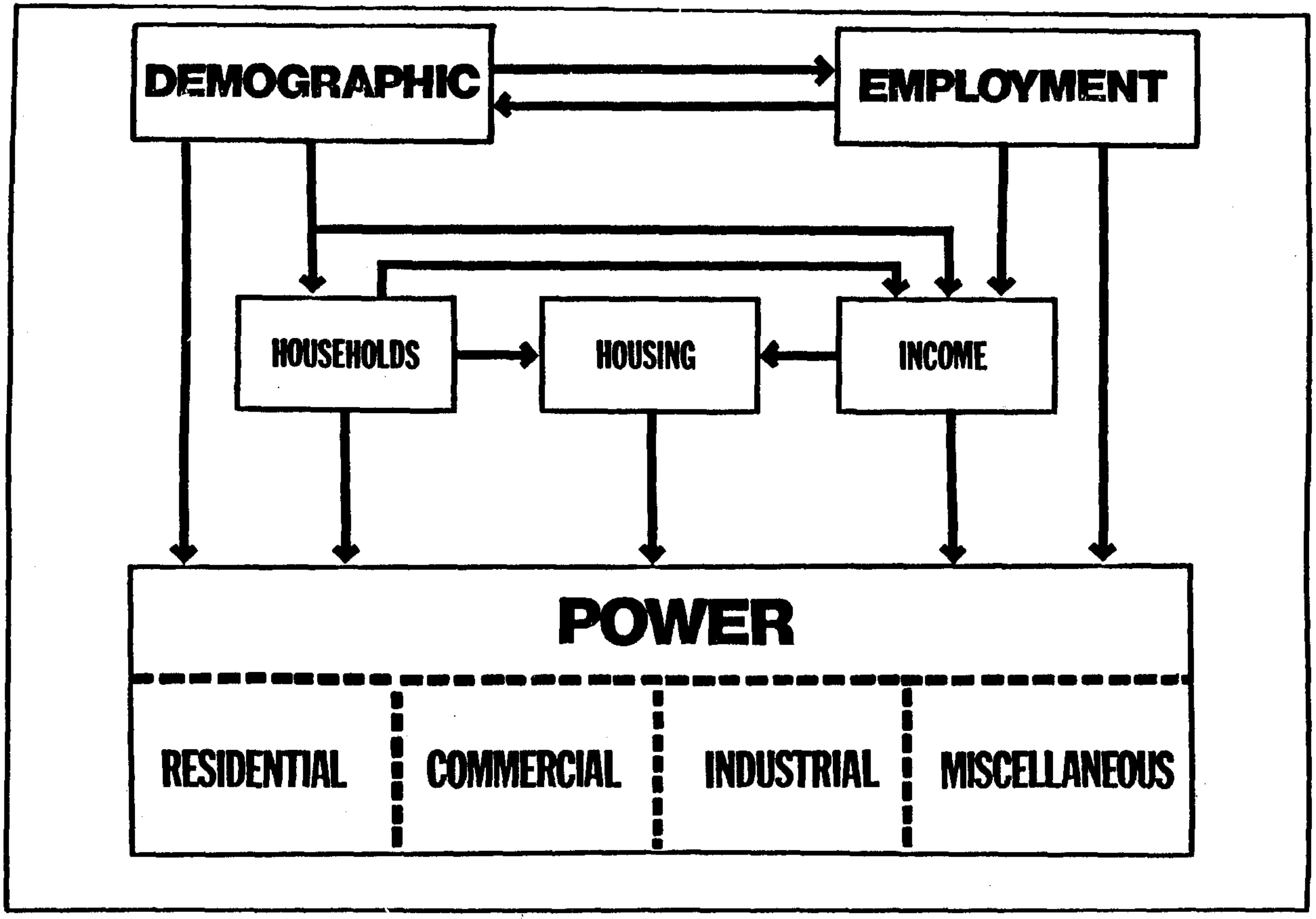
24 "The choice of methods employed in future NEGEA filings must be supported by a presentation of why the method was selected. This presentation should be based on an analysis of the resources and constraints to forecasting for NEGEA's service area, and an evaluation of alternative methods and why they are not feasible. This analysis should consider the availability, frequency, and level of detail of data on socio-economic variables, weather, customer bills, conservation and other key determinants of electricity demand." 6 DOMSC 1 (1981), at 30.

25 Stone and Webster report, p. 2.

FIGURE 2. STRUCTURE OF THE NEPOOL MODEL



Taken from the NEPOOL Model Documentation, Chapter entitled "Overview of the NEPOOL Model", May, 1982, p.6.

1. <u>Description of the NEPOOL Model as Adopted by Commonwealth</u>

The basic structure of the NEPOOL model consists of an economic /demographic module which produces population, employment, and housing forecasts. These in turn drive a power module that ultimately produces forecasts of electricity demand for specific end-uses within the residential, commercial, industrial and miscellaneous sectors. This structure, which Commonwealth has implemented essentially unchanged, is outlined in Figure 2.

The model incorporates regional economic and demographic trends in a framework generally consistent with the nature of electricity demand. This is accomplished in the following simulation context:

a. <u>Economic/Demographic Module</u>

- Population forecasts by age and sex are produced from a cohort-survival model, which tracks the distribution of population by age and sex through time.
- Migration adjustments to population are made for adults based on national and regional unemployment rates to reflect economic opportunity differentials. Migration of children is based on the number of adults, and elderly rates are exogenously supplied.
- Immigration adjustments to population are based on historical entry rates.
- Population forecast produces number of households from historical trends in household formation rates.
- Households are broken down to single family, multiple family, and mobile homes, based on historical percentages.
- Population forecasts produce a labor forecast from time-

trended labor force participation rates.

- Service area non-manufacturing employment is forecast as a function of population based on historical SIC-employment-to-population ratios.
- Service-area manufacturing employment is forecast by SIC either econometrically (as a function of NEPOOL-estimated state employment by SIC), or judgementally extrapolated.
- The effects of employment external to the service area is forecast based on historical commuting estimates.

b. Power Module

The "power module" combines the individual economic and demographic forecasts with price elasticities, conservation factors, end-use data, and industrial value-added to produce energy demand forecasts for each end-use category and aggregate class listed in Table 3. Energy and peak forecasts are produced for hourly, daily, weekly, monthly and annual increments.

- Residential

Residential forecasts are produced as the simple product of:

$$\text{Number of Appliances} \times \text{Connected Load per Appliance} \times \text{Fraction of Connected Load Operating} \times \text{Price Elasticity adjustment}$$

The number and type of households combined with projected appliance saturation rates produce the number of appliances. These provide the demographic/energy link in the residential sector. Temperature-sensitive and non-temperature-sensitive loads are calculated through the use of three separate probability matrices which include the time of day,

TABLE 3.**

END USES OF ELECTRICITY IDENTIFIED IN THE COMMONWEALTH MODEL

Residential (20)

Cooking
  Electric range
  Microwave oven
Refrigerators
  Frost free
  Standard
Freezers
  Frost free
  Standard
Dishwashers
Clothes Washers
Electric Clothes Dryers
Electric Water Heaters
  Controlled
  Uncontrolled
Television
  Color
  Black and White
Lighting
Air Conditioning
  Room
  Central
Electric Space Heating
Fossil Space Heating Auxiliaries
Second Homes
Miscellaneous Appliances

Commercial (35)*

Lighting
Miscellaneous Base Load
Air Conditioning
Electric Space Heating
Fossil Heating Auxiliairies

Industrial (20)

SIC 20 - Food
SIC 21 - Tobacco
SIC 22 - Textiles
SIC 23 - Apparel
SIC 24 - Lumber and Wood
SIC 25 - Furniture
SIC 26 - Paper
SIC 27 - Printing
SIC 28 - Chemicals
SIC 29 - Petroleum
SIC 30 - Rubber and Plastics
SIC 31 - Leather
SIC 32 - Stone, Clay and Glass
SIC 33 - Primary Metals
SIC 34 - Fabricated Metals
SIC 35 - Nonelectric Machiner
SIC 36 - Electrical Machinery
SIC 37 - Transportation
SIC 38 - Instruments
SIC 39 - Miscellaneous Manufacturing

Miscellaneous (5)

Street Lighting
Master Metered Apartments
Otis Air Force Base
Company Use
System Line Losses

* The five end uses are projected for seven commercial employment categories: Construction, Agriculture Forestry and Fishing, and Mining; Transportation, Communications and Public Utilities; Wholesale Trade; Retail Trade; Finance, Insurance and Real Estate, Services; Government and Military (excluding Otis Air Force Base).

** Taken from the Forecast, p. 1.4.11.

day of week and month or temperature (depending on the type of appliance). Energy, and peak loads for the residential sector are the end-product.

° Commercial

Annual commercial sales by SIC are forecast as a function of employment (from the Economic/Demographic module), annual kilowatthours consumed per employee, and saturation rates for each of five end uses. Annual KWH per employee is also an independent variable forecast as a function of price, and business hours in the case of base load. For temperature-sensitive load, KWH per employee is forecast as a function of the number of degree days and KWH consumed per degree day for primary heating, air conditioning, and fossil auxiliaries. Annual energy is distributed across months, days, and hours according to time-and-temperature-dependent use profiles.

° Industrial

Annual industrial electricity consumption is forecast by SIC code. The model generates the forecasts from estimates of KWH consumed per dollar of value added (by SIC) and the price of electricity. The important KWH-per-dollar-value-added variable is a measure of energy intensiveness within each industry. (Analogous to the KWH per employee measure for the commercial sector) To obtain KWH per dollar value added, value added is first forecast based on the industrial employment projection (from the Economic/Demographic module), projected hours-worked-per-production employee, and projected productivity rates by industry. Energy intensiveness (KWH per dollar value added) is then forecast as a function of the price of electricity. The product of these projections and value added yields forecasts of annual electricity demand by industry, which are allocated across months, days, and hours based on NEPOOL industrial load profiles.

° Miscellaneous

The Companies make explicit forecasts of electricity sales for street lighting; master-metered apartments; company use, Otis Air Force Base; and losses and unaccounted for, according to the following methods:

- ° Streetlighting - based on projected KWH per capita ratios, with consideration of lighting efficiency improvements
- ° Master Metered Apartments - assumed constant average use of 4900 KWH/year times a projected declining number of master metered units.
- ° Company Use and Otis AFB - held constant at 6,400 and 28,900 MWH/yr respectively.
- ° Losses and Unaccounted for - assumed to remain at 8.4% of net energy, based on 1970-1980 company data.

c. <u>Peak Demand</u>

The Commonwealth peak demand forecasts have been generated with the NEPOOL load profile data for each sector combined with service area temperature profiles. Load shapes and load duration curves, however, have been projected using averages experienced over the 1977-1981 period because the Company has not yet fully developed the models' capabilities in this area.

2. <u>Critique of Commonwealth's Adaptation of the NEPOOL Model</u>

The NEPOOL model as adopted by Commonwealth provides the Companies with a disaggregated end-use model which substantially improves its previous forecasting capabilities. This model commendably encompasses a methodology which resolves the fundamental weaknesses of the Companies' former highly judgemental survey-interview methodology. Most notably, the Commonwealth model allows for the explicit treatment of price, appliance efficiency and saturation, electric heat penetration, and conservation effects which have been repeatedly stressed by the Council. See 1 DOMSC 221, 2 DOMSC 66, 3 DOMSC 37, and 6 DOMSC 1.

The reviewability of the Companies' methodology has been another problem raised in previous Council Decisions and was the predominant cause of the Council's rejection of the last forecast. The Commonwealth methodology now consists of a systematic framework which has significantly improved the Council's ability to review Commonwealth's forecast. We note, however, that while the Companies provided their own fairly well documented forecast, Council staff could not conduct a complete review without heavy reliance upon NEPOOL's own documentation (of which the Council staff has only 17 of the updated 24 chapters).[26] This problem is particularly true of the technical documentation which presented the model's numerous underlying equations and their summary statistics, which can only be found in the NEPOOL documentation. Because, as Commonwealth stresses, it has adopted its own version of this model, concurrent review of the NEPOOL model and Commonwealth's implementation of the model has been necessary. This has made model review a somewhat lengthy and burdensome process. To the extent practicable, the Companies should continue to bolster their own documentation to eliminate the necessity for overlapping model review.

These comments are not, however, intended to minimize the fact that

26 The updated documentation is being provided by NEPOOL to the EFSC as it is being completed: "The NEPOOL Load Forecasting Model, an End Use Simulation Model for Long Range Forecasting of New England Electric Energy and Peak Demand," (Load Forecasting Task Force of the NEPOOL Planning Committee), chapters dated October, 1981 - present.

the systematic nature of the model and the available documentation have enhanced the overall reviewability of Commonwealth's methodology. Now that Commonwealth has presented a forecast where reviewability is not an overriding concern, we proceed on the more fruitful analysis of the appropriateness of the chosen methodology and the reliability of the forecasts.

The Company's adaptation of a disaggregated end-use model has placed Commonwealth's methodology in the ranks of the large electric utilities operating within the Commonwealth. Of the six "major" electric utilities (those with sales greater than 2% of total sales in the state) -- of which COM/Electric ranks fifth in terms of 1981 sales -- all have adopted wholly or in part an end-use approach to demand forecasting.[27] Of these companies, Boston Edison, NEES, and NU have principally relied on NEPOOL's population model, MMWEC has adopted the NEPOOL residential submodule and EUA and now Commonwealth have more or less adopted the entire NEPOOL framework.[28]

This advancement of Commonwealth's forecasting capabilities moves the Company many degrees toward satisfying the current needs of electric utility supply planning. Up until fairly recently, planning has only required a reasonable projection of peak demands in order to initiate the construction of new generating facilities. The 1970's and beyond, however, have seen a period of rapidly escalating construction costs

27 See Susan Fallows, "Report to the Energy Facilities Siting Council on the Electric Industry in Massachusetts," December, 1982, pp. 6 and 23-24.

28 See: the Long Range Forecasts for each company filed with the Council; and Fallows, ibid, pp. 23-24.

combined with shifting energy consumption patterns, which have rendered old-style utility planning obsolete. This evolution is exemplified by Com/Electric's present situation as a company financially strained by existing construction projects[29] and simultaneously facing the possibility of a capacity deficiency within the next 5 years (discussed in the supply analysis). Under these circumstances, capacity planning requires a reliable aggregate demand forecast based on disaggregated end-use analysis in order to better understand the nature of demand and to optimize the use of the present generation mix through load management, incentive rates, and alternative planning strategies. Therefore the Council finds Commonwealth's new methodology to be appropriate, in line with the methodologies of similarly sized companies, and that it should ultimately provide the Companies with the support their supply planning effort needs.

At this juncture, a useful distinction is drawn between the methodology itself and Commonwealth's adaptation of it to its service area. Even the best demand forecasting methods may produce unreliable results if data of sufficient quality are not available to run the model.[30] The NEPOOL model, being a regional forecasting tool with data disaggregated only to the state level, poses special problems in service area implementation. These problems are largely data related, but also involve the methodological question of whether the service area in question can be accurately modeled as a self-contained economic region.

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29 See: COM/Electric, Initial Response to DPU of Plans to Meet Forecasted Generation Deficiency and to Address the Problems Presented by the Current Degree of Oil Dependence (hereinafter "COM/Electric Initial Response), July 30, 1982, p. 14.

30 Hartojo Wignjowijoto, "Conceptual and Data Implementation Problems of Adapting the Base Case NEPOOL Model to Utility Service Areas", MIT Energy Laboratory Working Paper, April 10, 1981, MIT-EL-81-013WP.

The heart of the problem is attempting to simulate the economic and demographic behavior of a service territory as if it were independent when it is in fact part of a larger economic and demographic unit. The Companies note that the NEPOOL model, and in particular the Economic/ Demographic module, assume "that the economic and demographics of the service area do not, in the long run, maintain a separate existence."[31] Commonwealth has recognized the problem and has attempted to compensate for the effects of external economies on its service area through a net-commuting adjustment to the model.

Migration also poses difficulties. As it is specified in the model, migration occurs in response to economic opportunity differentials (represented in the model as the difference between national and service-area unemployment rates). This specification, however, fails to recognize the service area's interdependence with surrounding job markets that may exhibit very different levels of economic opportunity than that experienced in Commonwealth's service territory.

The effects of external economic influences on Commonwealth's service area, or any other service area, do not necessarily render the regional economic modeling approach in the NEPOOL model inappropriate. Rather, they dictate that the approach must be 'doctored' to accurately represent the interdependent economic and demographic characteristics of the service area and the larger region. The Council's concerns over specific economic and demographic components will be handled in the detailed Commonwealth model analysis, but a broader point should be stressed at this time.

31 Forecast, p. 1.4.13.

The modular structure of the NEPOOL model allows the Company to retain model components which perform best and to seek alternatives to poorly performing sections of the model. This point is highlighted in the model's documentation: "Another important characteristic of the NEPOOL model is its modular structure. That is, the model is divided into modules and submodules with simple linkages from one to another. This enables modification of one sector without major model overhaul as long as the linkage is undisturbed."[32] In its continuing process of adapting the NEPOOL model to its service area, the Company should pay heed to the efforts and resources needed to restructure the model so that it reflects the unique characteristics of its service area. It may be that independent forecasts of some of the key economic and demographic variables will provide the most reliable and cost effective data. This is the approach that Eastern Utilities Associates has taken in its implementation of the NEPOOL model.[33] To do this may sacrifice the internal consistency of the Economic/Demographic module, but consistency offers no advantage if it leads to unreliable forecasts.

The NEPOOL model is a simulation model which led the Company to take the following steps:[34]

- Data Base Development

  Starting with the NEPOOL model's data base for the state of Massachusetts, the values of input and assumption variables were replaced with service area data where available.

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32 NEPOOL model documentation, op. cit., "Overview of the NEPOOL Model," p. 4.

33 See EUA's 1981 Long-Range Forecast.

34 From COM/Electric response to Staff Information Request COMGM-3.

- Using the modified data base, the model was initialized with 1970 starting values. A simulation over the 1970-1980 period then proceeds resulting in energy forecasts for each customer class, along with a total energy forecast.
- At this stage, the Company used an iterative process of comparing the model's performance over the 1970-1980 period with actual experience, and then making model adjustments. Poorly performing sections of the model were adjusted using one or more of following three corrective measures:
    - "Level" adjustments were made to the constant terms in the model so as to minimize the historical prediction error. (This procedure was adopted, for example, to adjust NEPOOL appliance connected load data to fit Commonwealth's experienced residential sales.)
    - Model logic was changed and equations re-estimated. (For example, service area manufacturing employment was re-estimated based on state-level manufacturing employment in some instances, as opposed to the NEPOOL method of relating to national employment levels.)
    - Further "fine-tuning" was undertaken.
- Final service area forecasts were produced.

The Council again commends the Company for undertaking such an extensive effort to adapt this data-intensive and comprehensive end-use model to its service territory, but we feel compelled to express some concerns regarding the Company's model implementation.

Reliable forecasts are produced from quality data in conjunction with a methodology that can simulate those behavioral relationships that ultimately determine a population's energy consumption. As a practical matter, the costs of collecting service-area-specific data and developing a methodology must always be balanced against the anticipated marginal benefits of those actions and the Company's budgetary constraints. In the ideal situation, a methodology is developed which theoretically represents the service area's behavioral patterns, and is then tested against the company's historical experience with the use of territory-specific data. With a simulation model, this procedure allows for a fairly rigorous test of the chosen methodology.

Commonwealth, as with many companies of its size and resources, has chosen a relatively cost effective route of adopting a model developed elsewhere which utilizes many parameters and data series non-specific to the Company's service area. Upon doing so, both the methodology and data must be proven to be reliable for its service territory, as previously discussed. The fact that the Company has "calibrated" the model through the process outlined above instills confidence in the model's ability to predict the past, but unfortunately the nature of the process -- testing the simulated results against actual results and then adjusting parameters in some instances -- pre-empts the ability to now conduct an independent historical simulation. This is particularly true in light of the fact that model adjustments were not necessarily made on a statistical basis.[35] In this regard, a well known forecasting text offers that: "tuning a model can be a somewhat tricky business. By adjusting some of the coefficients, the analyst might make the model track the historical data very well, even though it is really a very poor representation of the real world, with very little predictive

35 See COM/Electric response to Staff Information Request COMGM-3c.

value. Coefficients should be adjusted only with great caution to a very limited extent, and only if they are not statistically significant."[36]

The Council is aware that if such methodological rigor were strictly adhered to , utilities might never generate forecasts, given data constraints. We note, however, that the greater the extent of service territory specific data collected, the greater the number of NEPOOL estimated parameters which may be replaced. This in turn minimizes the likelihood that the aforementioned "calibration" process may result in predictive error. It is, after all, predictive ability that measures a forecasting model's value. As the Commonwealth model and its data base stand now, reliability of the demand forecasts is a matter of concern to the Council.

D. Conclusions: Demand

Cambridge and Commonwealth have presented their joint Second Long-Range Forecast to the Council, which is summarized below:

Table 4

Forecast Average Annual Growth, 1982-1991

Sector	Cambridge	Commonwealth	Combined
Residential	0.0%	3.1%	2.9%
Commercial	2.8%	2.7%	2.7%
Industrial	-0.06%	3.1%	2.2%
Total Energy	1.9%	3.0%	2.7%
Peak Demand	1.6%	3.2%	2.9%

36 R.S. Pindyck and D.L. Rubinfeld, Economic Models and Economic Forecasts, (New York: McGraw-Hill, 1976), p. 359 under "Tuning and Adjusting Simulation Models."

The Council has reviewed the separate Cambridge and Commonwealth methodologies based on our standards for reviewability, appropriateness for the service area, and reliaiblity. In both instances, we find the methodologies to be reviewable and appropriate. These are noteworthy accomplishments for the Companies, particularly in light of our last rejection of the Companies methodologies on these very grounds.

Having satisfied these standards, we have proceeded to evaluate the reliability of the Cambridge and Commonwealth forecasts. Ideally, a utility demand model will produce accurate forecasts. Unfortunately, a model's accuracy can only be determined after the fact. Therefore, we concentrate on a related model attribute, reliability. If the modeler's broad assumptions concerning, for example, world energy prices, macroeconomic and demographic trends hold true, then a reliable model will produce accurate forecasts. Thus, many energy models which have produced inaccurate results over the 1970's may still be reliable models. We do not expect that the State's utilities will be able to predict such unforseen events as the Arab oil embargo. Rather, we expect each utility to reliably model consumption behavior within its service area. To this end, the Council has made several suggestions (and in 4 instances have imposed Conditions) to the Companies for improving the reliability of its developing methodologies. The presence of these suggestions and demand Conditions should not detract from the substantial progress that the Companies have made in presenting a reviewable and appropriate forecast. The reliability of the forecast, however, should be improved in future filings.

The Cambridge forecast, reviewed in the previous section, is approved without the imposition of Conditions. The Council urges

Cambridge to continue to improve the reliability and supply planning support value of its forecast by: extending the Commonwealth (or some other) Appliance Saturation Survey to Cambridge; developing a Cambridge specific baseline commercial forecast; monitoring and reporting the accuracy of the individual industrial forecasts from surveys; and to consider the MMWEC forecast for Belmont in future filings. Commonwealth has adopted an end-use model which has significantly advanced the Company's forecasting capabilities. The model simultaneously satisfies past Council concerns with the Company's methods and offers the potential to satisfy the increasingly complex needs of the Companies' overall supply planning function. The Companies are highly commended for their accomplishments in this regard.

A complete technical analysis of the Commonwealth model is presented in section V of this Decision, while a broader methodological overview has been presented here. The following conclusions and Conditions emerge from both sections of the analysis.

We have found the model's overall framework appropriate for Commonwealth's service area, but differences among the service area's economic and demographic behavior and that of the region raise concerns over the applicability of the demographic-employment linkages in the model. The Council, in this regard, urges Commonwealth to re-evaluate its migration and commuting specification.

The Council concludes that the Company's major hurdle to continued progress is a lack of service-territory-sepcific data. Commonwealth has attempted to mitigate this problem through "calibrating" non-territory-specific-data and parameters to "fit" historical experience. The nature of this process raises important questions concerning the predictive ability of the current forecasting version of the model. These potential problem areas are, at this time, of an uncertain magnitude because the overall sensitivity of the model to changes in any of its numerous parameters or data inputs is unquantified. We therefore direct the Company, in Demand Condition number 1, to conduct a sensitivity analysis of the model prior to its next filing.

The Council awaits the completion of the Company's sensitivity analysis before encouraging or ordering the collection of costly data. We do, however, require the Company to take full advantage of existing research and/or data to demonstrate the applicability of the NEPOOL residential and commercial end-use data and price elasticities for its service territory. These directives are incorporated in demand conditions numbers 2, 3, and 4.

The Companies have provided the Council with Commonwealth and Cambridge "1983 Project Lists" which show recognition of many of the Council's demand side concerns expressed in this Decision. These work plans also incorporate tasks which commendably go beyond those which the Council has encouraged or ordered. We expect that the following conditions, suggestions made throughout the decision, and the Companies' own priorities will improve the reliability of future forecasts.

E. Demand Conditions

1. That the Companies conduct a sensitivity analysis of the Commonwealth model, and submit the results of this analysis with their next filing.

2. That the Companies perform an in-depth literature search on residential appliance connected loads and use profiles, and demonstrate the applicability of the NEPOOL data for the Commonwealth service area in light of the research, or address appropriate changes in the residential data base with their next filing.

3. That the Companies perform an in-depth literature search on commercial kilowatthour-use-per-employee estimates, by end use, and demonstrate the applicability of the NEPOOL data for the Commonwealth service area in light of the research or address appropriate changes in the commercial data base with their next filing.

4. That the Companies perform an aggregate price elasticity study, by customer class, for the Commonwealth service area. The study should include electricity prices, prices of substitute fuels, and income at a minimum. The Companies should attempt to demonstrate the applicability, or lack thereof, of the NEPOOL elasticities in light of this study, and submit these results with their next filing.

III ANALYSIS OF THE ENERGY MANAGEMENT PLAN

COM/Electric revealed its Energy Management Plan (EMP) in August 1982. The EMP explains a set of conservation programs the Companies are undertaking in hopes of reducing their oil consumption, forestalling the need for new capacity additions, and helping to keep their customers' bills as low as possible.[37] While the EMP is part of COM/Electric's overall long range plans, the Companies began to implement the measures identified in the EMP only at the end of 1982 and the Companies did not therefore account for the impacts of these measures in the long-range demand forecast under Council review at present.[38]

COM/Electric's EMP includes eight programs that focus on: increasing customers' awareness of the potential for end-use conservation; informing customers of specific cost-effective means they could implement to conserve electricity; providing services and financial incentives to induce customers to adopt specific conservation measures; and acquiring information about the effects of selected conservation strategies, load management techniques and wind resources. Table 5 identifies the EMP program and describes each one in terms of its projected customer participation, expected costs, and estimated KWH savings.

The measures in COM/Electric's EMP appear to be well targetted: In the residential sector, for example, they are directed towards reducing the energy consumption of appliances that are forecasted to use high

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37 Exhibit COMCON-3, pp. 3-4.
38 COM/Electric response to EFSC Staff Information Request COMCON-1.

Table 5

COM/ELECTRIC'S ENERGY MANAGEMENT PLAN:

PROGRAM SUMMARY

PROGRAM	PARTICIPATION	ESTIMATED PROGRAM COST	ESTIMATED SAVINGS KWH	ESTIMATED SAVINGS BBLS OIL
1. Wrap and Weatherization	2,100	$79,100	2,200,000	3,300
2. Mass Save/Electric Heat	800	73,000	1,120,000	1,680
3. Low Income Weatherization Assistance	5,000	48,700	-	-
4. Energy Audits - Commercial, Industrial, Governmental	250-Pilot	102,500	1,875,000	2,800
5. Bill Messages Encouraging Conservation	All Customers	10,000	-	-
6. Information Resource Staff		25,000	-	-
7. Direct Load Control Study	Study	53,000	-	-
8. Wind Data	-	3,000	-	-
TOTAL		$394,300	5,195,000	7,780

NOTE: These estimates of customer participation, program costs, and estimated savings are for the first year of the EMP.

SOURCE: COM/Electric Energy Management Plan (COMCON-3), Table 1 (p. 5).

percentages of the total amount of electricity used in the sector.[39] It is, however, difficult to determine the actual merits of the measures since the EMP's programs have been started quite recently and the Companies have just begun to collect data about their implementation and effects. In the EMP itself, the Companies do not provide sufficient information about how they estimated program costs, participation rates or energy savings, or how they set subsidy levels. Nor do the Companies provide information to explain why they chose these measures and not others. Lacking such information, the EMP programs are not truly reviewable and it is impossible for the Council to determine whether the measures are appropriate or whether the Companies' estimates of their costs and benefits are reliable.

The Companies recognize that "the programs delineated in this document [EMP] are a modest beginning for a system energy management program," and that they represent "the system's initial effort."[40] The Council supports these first programmatic steps and sees them as complementing the Companies' on-going efforts to improve their forecasting methods to account for the effects on demand of price-induced conservation and changes in government standards for appliance efficiency. The Council wants to see COM/Electric build on these efforts and implement

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39 For example, the WRAP program affects electric water heaters, which the Companies estimated to account for 12.2% of total energy consumed in the residential sector in 1982. The MASS-SAVE/ELECTRIC HEAT program and the LOW-INCOME WEATHERIZATION program are aimed at conserving energy used for space heating, which was estimated to make up 10.5% of residential electricity use. However, refrigerators -- the appliance with the highest percentage of energy use, at 20.5% -- were not directly affected by the EMP measures. (Calculations of percentages based on information on pp. 1.4.117 - 1.4.119 of COM/Electric's Forecast).

40 COMCON-3, pp. 3-4.

its conservation programs in ways that enable the Companies to analyze the costs and benefits of the program options and to use information on program impacts in future efforts to forecast demand.

In recent decisions on other electric utilities, the Council has commended the companies for developing conservation strategies[41] and, in some cases,[42] it has directed the companies to use the opportunity to: acquire territory-specific experience and data on implementation of conservation measures; monitor the effects of individual measures on energy savings and customers' bills (including the bills of customers who do not participate in the conservation programs); and analyze the relative life-cycle costs and benefits of the programs.

The Council directs the Companies to prepare a framework for monitoring and evaluating alternative conservation strategies. In the case of COM/Electric, the opportunity to develop a useful analytic methodology is particularly timely considering the developmental status of the Companies' conservation program,[43] the Companies' expressed commitment to promoting more efficient use of electric energy by all customers,[44] the customers' interests in reducing the Companies' use of oil,[45] and the potential for capacity shortfalls later on in the decade.[46]

41 See: In Re NEES, 7 DOMSC 270 (1982), at 309-310; and In Re EUA, 5 DOMSC 10 (1980), at 38.

42 See: In Re N.U., 8 DOMSC ___ (EFSC 81-17)(1982), at 58-63, 77; and In Re BECo, 7 DOMSC 93 (1982), at 160-163.

43 See: COM/Electric Response to Staff Information Request COMCON-2.

44 See: COMCON-3, p. 4.

45 Ibid.

46 See the discussion in section 4 (Analysis of the Supply Plan) of this decision.

Therefore, as part of this Decision, the Council directs the Companies to meet within 90 days with the staffs of the EFSC and the Executive Office of Energy Resources to discuss plans for data collection and analysis of energy conservation measures. Also, the Council requires that the Companies submit, as part of their next filing, an analysis of the long-range costs and benefits of alternative conservation measures.

IV. ANALYSIS OF THE SUPPLY PLAN

A. Introduction

The Companies own or have entitlements in various electric generating facilities. Table 6 identifies the generating units owned by COM/Electric as of December 1982. It also indicates COM/Electric's capacity purchases and sales. Actual plant ownership is divided among the three companies of COM/Electric -- Canal Electric Co., Cambridge Electric Co. (CELCo) and Commonwealth Electric Co. (Comm. Elec.) -- and the distribution of ownership reflects the historical plant holdings of the three separate electric companies before their merger.

The Companies presently rely on oil-fired electric generating stations for 82.0% of their capacity[47] and, in 1980, for 77.5% of their actual energy.[48] The remaining 18.0% capacity and (again in 1980) 22.5% of energy is supplied by nuclear power.

The three companies have a total system capability (owned capacity, plus purchases, less sales) amounting to 831.5 MW, as shown in Table 7. This net capability is more than adequate to meet the Companies projected capability responsibility of 737 MW for the winter of 1982-83.

But, as the Companies recognize, their "forecast of capacity needs shows that it [COM/Electric] has sufficient capacity only through 1986. Thereafter, additional capacity must be secured either by reason of ownership or firm power purchases."[49] The Companies' forecast of expected loads through 1991 is described in detail in previous sections of this decision and is summarized in Table 8 (see lines 1-3).

47 See Table 6.
48 See Exh. DOC-6e(1) and (2), p. 2.
49 COM/Electric Initial Response, p. 7.

Table 6

COM/Electric: Existing Generating Facilities
(as of 12/1982)

TEGORY	UNIT	LOCATION	Winter RATING (MW)	FUEL TYPE	OWNERSHIP (%) CANAL	CELCO	COMM. ELEC.	OWNERSHIP (MW) CANAL	CELCO	COMM. ELEC.
SELOAD:										
	Canal Unit No. 1	Sandwich	568.0	No. 6 Oil	100			568.0		
	Blackstone No. 3	Cambridge	2.9	No. 6 Oil*		100			2.9	
	Kendall No. 1	Cambridge	18.0	No. 6 Oil*		100			18.0	
	Kendall No. 2	Cambridge	23.0	No. 6 Oil*		100			23.0	
PURCHASES (OR SALES):										
	Yankee Atomic	Rowe	175.8	Uranium	Life of Unit Contract(2.9%,2.5%)				3.5	4.5
	Maine Yankee	Wiscasset, ME	829.9	Uranium	Life of Unit Contract(3.59%)				30.0	
	Conn. Yankee	Haddam Neck, CT	582.0	Uranium	Life of Unit Contract(4.5%)				26.0	
	Vermont Yankee	Vernon, VT	528.0	Uranium	Life of Unit Contract(2.25%)				12.0	
	Pilgrim No. 1	Plymouth	670.0	Uranium	Life of Unit Contract(11.0%)					74.0
	(Canal Unit No. 1)	(Sandwich)	(568.0)	(No. 6 Oil)	(25% ea. to BECo, NEPCo, EUA)			(426)		
	Canal Unit No. 1	Sandwich	568.0	No. 6 Oil	Contract with NEPCo (exp. 10/83)					25.0
CLING:										
	Kendall No. 3	Cambridge	29.0	No. 6 Oil*		100			29.0	
	Canal Unit No. 2	Sandwich	584.0	No. 6 Oil	50			292		
	Cannon No. 1	New Bedford	25.4	No. 6 Oil		100				25.4
	Cannon No. 2	New Bedford	35.2	No. 6 Oil*		100				35.2
	Wyman No. 4	Yarmouth, ME	585.0	No. 6 Oil		1.43				8.38

Table 6 (cont.)

COM/Electric: Existing Generating Facilities
(as of 12/1982)

TEGORY	UNIT	LOCATION	Winter RATING (MW)	FUEL TYPE	OWNERSHIP (%) CANAL	OWNERSHIP (%) CELCO	OWNERSHIP (%) COMM. ELEC.	OWNERSHIP (MW) CANAL	OWNERSHIP (MW) CELCO	OWNERSHIP (MW) COMM. ELEC.
AKING:										
	Blackstone No. 1	Cambridge	16.0	No. 6 Oil*		100			16.0	
	Blackstone No. 4	Cambridge	2.9	No. 6 Oil*		100			2.9	
	Kendall J1	Cambridge	24.0	Jet		100			24.0	
	Kendall J2	Cambridge	24.0	Jet		100			24.0	
	W. Tisbury No. 1	W. Tisbury	2.75	Diesel			100			2.75
	W. Tisbury No. 2	W. Tisbury	2.75	Diesel			100			2.75
	Oak Bluffs No. 1	Oak Bluffs	2.75	Diesel			100			2.75
	Oak Bluffs No. 2	Oak Bluffs	2.75	Diesel			100			2.75
	Oak Bluffs No. 3	Oak Bluffs	2.75	Diesel			100			2.75

Unit is capable of burning natural gas

SOURCE: Com/Electric Long Range Electric Forecast (1982-1991), Vol. 2.

Table 7

COM/Electric System Capability

	OWNERSHIP (MW)				
	CANAL	CELCO	COMM. ELEC.		COMBINED COMPANIES
TOTAL CAPACITY	860.0	139.8	82.73	=	1082.53 MW
TOTAL PURCHASES	0	71.5	103.5	=	175.00 MW
TOTAL SALES	(426.0)	0	0	=	(426.00) MW
NET CAPACITY AVAILABLE	434	211.3	186.23	=	831.53 MW
PROJECTED PEAKLOAD (winter 1982)	-	-	-		630.0 MW
CAPABILITY RESPONSIBILITY (winter 1982)	-	-	-		737.0 MW

SOURCES: For Capacity, Purchases, Sales: See Table 6.
For Projected Peakload: See Com/Electric Forecast, Table E-17.
For Capability Responsibility: See Com/Electric Response to EFSC Staff Information Request SCR-6 (based on NEPOOL Reserve Requirement for 1982 of 17% of peakload).

Table 8

COM/Electric Load and Capacity Forecast

	1982 winter	1983 winter	1984 winter	1985 winter	1986 winter	1987 winter	1988 winter	1989 winter	1990 winter	1991 winter
. Projected Peakload - MW	630	649	675	697	718	737	757	777	795	812
. NEPOOL Reserve Requirements	17%	15%	18%	21%	24%	24%	23%	23%	22%	22%
. Projected Capability Responsibility - MW	737	746	797	843	890	914	931	956	970	991
. Firm Capacity Commitments - MW										
a. Net Capability	809	809	809	809	809	809	809	809	809	809
b. Seabrook No. 1	0	0	40.5	40.5	40.5	40.5	40.5	40.5	40.5	40.5
c. Seabrook No. 2	0	0	0	0	0	40.5	40.5	40.5	40.5	40.5
a. Pt. LePreau No. 1	25	25	25	25	25	25	25	25	25	0
. TOTAL FIRM CAPABILITY COMMITMENTS - MW	834	834	874.5	874.5	874.5	915	915	915	915	890
. EXCESS (DEFICIT) - MW	97	88	77.5	31.5	(15.5)	1	(16)	(41)	(55)	(101)
. PROSPECTIVE SUPPLY ADDITIONS - MW										
a. Hydro-Small Power	0	0	0	0	12	12	12	12	12	12
b. Hydro-Quebec	0	0	0	0	30	30	30	30	30	30
c. SEMASS	0	0	15	15	15	15	15	15	15	15
d. Alternative Resources	0	0	0	2	2	2	2	2	2	2
e. Load Management	0	2	4	6	8	10	12	14	16	18
. NET CAPABILITY (FIRM + ADDITIONS) - MW	834	836	893.5	897.5	941.5	984	986	988	990	967
. EXCESS (DEFICIT) - MW	97	90	96.5	54.5	51.5	70	55	32	20	(24)

OURCES: See Following Page.

)URCES FOR Table 8

.ne 1: Projected Peakload: COM/Electric Forecast Table E-17 (includes sales to Belmont but not interruptibles). Also: COM/Electric, Initial Response, Exhibit 5.

.ne 2: NEPOOL Reserve Requirements: Percentage of peakload required for reserve responsibility, from COM/Electric Response to EFSC Staff Information Request SCR-6. See also: COM/Electric, Initial Response, p. 10.

.ne 3: Projected Capability Responsibility: Calculated from lines 1 and 2: (line 1 + (line 1 X line 2)).

.ne 4: Firm Capacity Commitments:

a. COM/Electric, Initial Response, Exhibit 2. This figure differs from the number in Table 4 due to rounding and because COM/Electric's, Initial Response, (Exh. 2) does not include a capacity purchase from NEPCO for 25 MW (since the contract expires 10/1983).

b. COM/Electric, Initial Response, Exhibit 2, with date of capacity addition postponed 10 months as per COM/Electric letter of January 5, 1983.

c. COM/Electric, Initial Response, Exhibit 2, with date of capacity addition postponed 10 months as per COM/Electric letter of January 5, 1983.

d. COM/Electric, Initial Response, Exhibit 5, with confirmation of purchase as per COM/Electric letter of January 5, 1983.

ine 5: Total Firm Capability Commitments: Sum of lines 4a - 4c.

ine 6: Excess (Deficit): line 5 minus line 3.

ine 7: Prospective Supply Additions: (a-e): COM/Electric, Initial Response, Exhibit 5.

ine 8: Net Capability: Sum of lines 5 and 7 (a-e).

ine 9: Excess (Deficit): line 8 minus line 3.

Table 8 also indicates the Companies' forecast of firm capacity commitments through the next decade (see lines 4-5). This forecast includes the additions of 40.5 MW of Seabrook Unit No. 1 on December 31, 1984, 40.5 MW of Seabrook Unit No. 2 as of March 1987, and a purchase of 25 MW in the Canadian Point LePreau Nuclear Unit No. 1 (from the first quarter of 1983 through October 1991).[50]

Using Table 8 to compare the Companies' total firm capacity commitments (line 5) and their capability requirements (line 3) for each year, one can see that a capacity deficiency (line 6) will occur in the winters of 1986 and 1988, and then continue through the remainder of the forecast period, unless additional sources of supply are utilized.

To meet its projected growth in peakload demand, COM/Electric has prepared a supply plan[51] to provide incremental additions of capacity to the systems' firm capacity commitments. These prospective supply additions are summarized in Table 8 (lines 7a - 7e) and described in more detail later in this section. With these capacity additions, COM/Electric expects to have sufficient capacity to meet its forecasted capability requirements until the winter of 1991, when a deficit is projected to occur.

These additional projects are also expected to significantly reduce the Companies' dependence on oil by the end of the decade. If all of the capacity additions are realized as planned, the Companies' generation mix will become more diversified:

50 See letter dated January 5, 1983 (from Dennis Henzel, COM/Electric, to Susan Fallows, EFSC).

51 COM/Electric, Initial Response.

COM/Electric Generation Mix (Energy) by Fuel Type[52]

	1980 (actual)	1990 (estimated)
oil-fired plants	77.5%	45.9%
nuclear plants	22.5	37.8
hydroelectric plants	-	12.4
alternative energy facilities	-	3.9
	100.0%	100.0%

(This reduction in oil dependency by 1990 is less than the Companies had expected to achieve a few years ago, because several of the nuclear projects in which the Companies were participating were cancelled.[53] These nuclear units were scheduled to have come on-line during the 1982-1991 forecast period and would have added 198 MW of baseload capacity to the COM/Electric system. According to the Companies, the cancellations have meant that "COM/Electric is left with too little capacity and continuing dependence on fuel oil for generation...."[54])

The Council commends the Companies for their recognition of these supply problems and for their initial efforts to remedy them through their supply plan. The Council has carefully analyzed the Companies' supply plans and has identified a number of areas of potential concerns about the reliability, adequacy, diversity, and cost implications of the plans.

Assuming arguendo that the Companies' forecast of growth in peak demand proves correct, the actual timing and magnitude of a capacity shortfall appear uncertain and could occur before the winter 1991 time period the Companies identify in their plan (See Table 8). Given

52 COM/Electric, Initial Response (Exh. 8, Sheet 3 of 3).
53 Five units were cancelled: Boston Edison's Pilgrim No. 2; NEES' NEPCo Unit No. 1 and No. 2; and NU's Montague Units No. 1 and No. 2.
54 COM/Electric, Initial Response, p. 6.

the small number of firm capacity commitments, the developmental status of some of the Companies' plans for further supply additions (or load reductions), as well as the importance of a number of external variables on the timing of certain capacity additions (e.g., Seabrook No. 1 and No. 2, SEMASS, and Hydro Quebec), the Council believes that a deficit could occur as early as the winter of 1985-86.

The following sections describe specific Council concerns regarding: the appropriateness of the Companies' dates for commercial operation of the Seabrook units; the ability of the Companies to effectively manage their peakload demand; the aggressiveness with which the Companies are pursuing the development of renewable or alternative energy resources; the Companies efforts to obtain Canadian energy; and the adequacy of the Companies' supply.

In the interests of prudent planning, the Council is concerned that the Companies recognize the optimism of their current supply plans and that they take steps to prepare contingency plans for how they will meet potential capacity shortfalls if projects do not come on-line as expected. Additionally, the Council notes that even if every prospective capacity addition comes through on schedule, the Companies still anticipate a capacity deficit at the end of their forecast period. Such a situation is unacceptable to the Council; and we will order the Companies to resolve this problem of inadequate supply in their next filing. These concerns are discussed below and will be addressed in the conditions of this decision.

B. The Seabrook Units

The Council has in the past noted that the Seabrook commercialization dates are themselves a subject of continual dispute.[55] The Companies project that the Seabrook Nuclear Units 1 and 2 will begin commercial operation on December 31, 1984 and March 31, 1987 respectively.[56] The lead owner (Public Service Co. of New Hampshire) recently announced these revised target dates, which represent a ten-month slippage for each unit. However, even before this most recent schedule slippage, the owners of the second and third largest shares (MMWEC and NEES) projected on-line dates as late as 1986 for Unit No. 1 and 1988 for Unit No. 2. The Council recognizes that until recently the ability of the joint owners to even continue to invest in Unit No. 2 was in question,[57] and that the resolution of this issue will allow construction on Unit 2 to begin again (even though previous delays cannot physically be made up, according to the New Hampshire Public Utility Commission).

In our recent decisions concerning Eastern Utilities Associates,[58] the New England Electric System,[59] and Fitchburg Electric Co.,[60] we have discussed the problems associated with Seabrook. They included difficulties with labor contracts, attracting capital, cost escalation and the problems of obtaining an operating license from the Nuclear Regulatory Commission. We will not repeat those discussions here. In each of those cases, however, we found that the companies had sufficient

55 For a full discussion see: In Re E.U.A. 8 DOMSC ____, EFSC No. 82-33 (1982) at pp. 30-34.
56 See COM/Electric letter dated January 5, 1983.
57 See PSNH v. NHPUC, ____ NH ___, ___ A 2d ___, No. 82-366 (December 27th, 1982).
58 In Re EUA, Ibid.
59 7 DOMSC 270 (1982), at pp. 308-309.
60 7 DOMSC 238 (1982), at pp. 249-258.

capacity to cope with the delay of Unit 1 and the indefinite postponement or possible cancellation of Unit 2. Such does not appear to be the case with COM/Electric. Considering just the Companies' current set of firm capacity commitments (see Table 8, line 4), the Companies can absorb only an additional one-year delay in the completion of Seabrook No. 1 if they want to want to avoid a capacity shortage. (In fact, it is the recent Canadian NEB approval of the export of Canadian power from Pt. LePreau No. 1 that enables the Companies to absorb another year of delay.) Without Seabrook No. 1 operating in the winter of 1985-86, the Companies will experience a capacity shortfall -- a situation that could seriously increase COM/Electric customers' electricity costs insofar as the Companies would be forced to rely on surplus, oil-fired capacity from NEPOOL. This would be unacceptable to the Council. COM/Electric can absorb further delays in Seabrook No. 2 only if other supply projects (i.e., Hydro-Quebec and either SEMASS or load management or small hydro projects) are actually on-line by the winter of 1987.

The Companies have recently expressed interest in obtaining further capacity entitlements in Seabrook as a way to remedy future supply problems.[61] Given the continuing uncertainty over the timely completion of Seabrook No. 1 and No. 2, and given the likelihood that lengthy postponements will exacerbate COM/Electric's capacity problems, the Council questions the Companies' plans in this direction. In fact, the Companies' own estimates[62] of costs-per-KWH for energy from Seabrook No. 1 and No. 2 and from Pt. LePreau No. 1 show the Seabrook Units' KWH costs exceeding Pt. LePreau's by at least a factor of two. (And since

61 COM/Electric, Initial Response, pp. 25-26.
62 COM/Electric Response to EFSC Staff Information Request SCR-1.

these cost estimates were prepared before recently announced increases in Seabrook's total costs,[63] presumably the differential between the costs of Seabrook energy and Pt. LePreau energy is even larger now.) The Council discourages the Companies from increasing their Seabrook entitlements before they undertake a thorough analysis of the costs and benefits of obtaining energy from alternative resources (see sec. 4 below) or the costs and benefits of reducing peakloads through load management techniques (see sec. 3 below). Supply Condition 4 addresses these concerns.

We find that the Companies' supply plan is faulty with regard to nuclear power in that it does not demonstrate contingency plans in the event that the Seabrook stations are delayed beyond currently projected dates. The capacity from the two Seabrook units is expected to represent 8.3% of the Companies' capacity requirements in 1990 and to reduce the Companies' dependence on oil by 15.3% by that same date. They represent the most significant additions to the Companies' supply system over the forecast period and will be of critical concern to the Council during most of this decade. We will, therefore, require the Companies to file semi-annual reports with the Council on PSNH's progress on the two Seabrook units and to prepare as part of their next filing a contingency plan showing how the Companies will meet their capability responsibility in the event of further delays in the Seabrook units. Supply Condition No. 1 addresses these actions.

C. Management of Peak Demand

The Companies state that they will use load management techniques

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63 From $3.56 billion to $5.12 billion (See "Seabrook N-Plant Price Rises $1.5 b," Boston Globe, December 1, 1982, p. 1).

to reduce peak demand by 2 MW/year over the forecast period.[64] The Companies propose to do this through direct control of electric hot water heaters and time-of-use incentive rates.[65] The Companies propose that this program will reduce peak demand by 6 MW by 1985 and 18 MW by 1991.

Toward this end, the Companies have initiated a Direct Load Control Study as part of their Energy Management Plan. The study will "investigate and evaluate the alternatives available for control of customer-owned appliances with emphasis on the electric heating load."[66]

The Council is encouraged that the Companies are beginning to implement a demand management strategy aimed at controlling peakload growth and deferring the need for new capacity. Such was the intent of Supply Condition No. 1 in our last Decision and Order on the Companies' forecast, requiring the Companies "to appraise thoroughly the potential for direct control of major residential and commercial appliance loads for the purpose of load factor improvement."[67] We do not, however, believe that the Companies go far enough in this regard.

The Companies project that they will become a winter peaking system during the forecast period.[68] COM/Electric forecasts Commonwealth Electric's peakload to increase at a compound annual growth rate of 3.2% between 1982-1992.[69] Commonwealth Electric's "system load factor is expected to decrease from about 63% in 1982 to 61% in 1991, due primarily to the increasing penetration of electric space heating."[70] In

64 COM/Electric, Initial Response, Ex-5, pp. 17-18; see also Table 8.
65 ibid, p. 18.
66 Exhibit COMCON-3, Program 7.
67 6 DOMSC 1 (1981), at 30.
68 COM/Electric, Executive Summary of EFSC Forecast, p. 2.
69 ibid, p. 6.
70 ibid

1981, Commonwealth Electric sold 214,702 MWH of electricity to the residential-with-electric-heat customer class, representing 9.4% of total sales. Further, COM/Electric projects that by 1991 these totals will be 441,500 MWH or 14.5% of total sales.[71] Given this forecast of growth of highly temperature-sensitive, on-peak demand, along with the related worsening of the system load factor and the Companies' overall supply problems, we believe that COM/Electric should make more aggressive efforts in load management. To this end, we require the Companies to meet with Council staff to discuss the range of load management strategies the Companies have under consideration, as well as the Companies' plans for monitoring and analyzing the costs and effectiveness of alternative load-management techniques. Supply Condition 3 addresses these requirements.

While the Companies project no growth in Cambridge's residential class over the next decade, they project significant growth in Cambridge's commercial class. The Companies are fortunate in having knowledge of the specific new loads (in the form of new or renovated buildings). Here, the Companies have the opportunity to help defer capacity and reduce oil consumption by directly working with the developers of these buildings to insure that they are aware of the Companies' proposed time-of-use rates, their commercial energy audits and the availability of energy management systems. This could help to reduce the size of those new load additions and their contributions to peakload, and might keep those commercial customers from switching to other sources of energy in the future.[72] Condition number 3 also

71 COM/Electric Forecast, Table E-8.

72 As the Federal Economic Recovery Tax Act of 1981 provides investment tax credits for this type of renovation work, COM/Electric (and other electric companies) should be aware of the increased potential for urban renovation work. See: IRC sec. 46(a)(f).

addresses this issue.

Lastly in this area, the Companies have set out in some detail the costs of some of their new capacity additions.[73] They have not, however, compared those costs to the costs of investments in demand management over the useful life of the investment. We have in the past ordered that a company perform such a cost-benefit analysis[74] when the need for such strategies was less pressing than in this case. In this instance we will require the Companies to perform a similar analysis in order that we might determine, during the Companies' next forecast review, which supply strategies are in fact the least-costly and most environmentally acceptable to meet projected need. M.G.L. c. 164, sec. 69I, J. Again, Supply Condition No. 4 addresses this issue.

D. Energy from Co-generation and Renewable Resources

By 1991, the Companies project to obtain 33 MW of capacity (or load reduction) from sources using renewable resources (solar, wind, hydroelectric and biomass) and co-generation. (See Table 8) Of this 33 MW, 15 MW is expected to come from the SEMASS municipal solid waste fueled power plant,[75] 12 MW from the Boott Mills Lowell Hydro Project and other small hydroelectric projects,[76] and 6 MW from the remaining alternative resources.[77]

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73 COM/Electric, Initial Response, pp. 25-32, Exh. 7.

74 In Re Northeast Utilities, 8 DOMSC ____, EFSC 81-17 (1982).

75 COM/Electric has a long-term contract for purchase of electricity from Energy Answers Corp's SEMASS facility, being developed in Rochester, Massachusetts. It is scheduled for completion in 1984, but may be delayed as SEMASS is having trouble in its negotiations with local communities for municipal refuse contracts.

76 COM/Electric has signed a long-term contract with Corporation Investments, Inc., to obtain 51% (11.5 MW) of capacity from the Boott Mills hydroelectric facility in Lowell. In addition, if MMWEC does not exercise its option for the remaining 49%, COM/Electric will acquire the rest of the capacity.

77 These include a gas expander turbine to be used for R&D purposes to generate electricity from pressure differentials on the COM/Gas system.

The Companies are to be commended for their initial efforts to pursue energy from these resources in compliance with the Council's directive in its last order.[78] The Council believes these are preliminary steps in exploring renewable resource use in the Companies' capacity and generation mix. The Council encourages COM/Electric to adopt a more aggressive role in initiating contracts with potential developers of alternative energy projects and in analyzing the costs and benefits to the Companies of direct investment in electricity from renewable resources.

The Council is concerned, in particular, over the Companies' lack of success in acquiring any significant capacity or energy from co-generation. This is especially disturbing in light of the forecasted 3.1% annual growth in sales of electricity to the industrial class (1982-1991) for Commonwealth Electric, and the large existing industrial class in Cambridge (37% of total sales in 1981). These indicate areas of opportunities and need for pursuing cogeneration projects. COM/Electric is not, of course, limited to its own service territory in pursuit of such capacity. Other companies -- MMWEC, NEES, and NU particularly -- have entered into several co-generation agreements, and we must question COM/Electric's failure in light of these successes.

In addition, Commonwealth Electric has a large coastal service territory with excellent potential for the development of wind powered energy.[79] The Companies have begun to monitor wind resources in their service territories. While the Companies have entered into a number of

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78 See Supply Condition No. 2, 6 DOMSC 1 (1981), at 31.

79 See: The New England Energy Atlas (Hanover, N.H.: Resource Policy Center of the Thayer School of Engineering, Dartmouth College, July 1980), pp. 11-12.

agreements for energy purchases with private owners of these machines, it has not seen fit to invest in such capacity itself.

Also, the Companies are considering the purchase of 10 percent of the electricity produced at the proposed 280 MW coal gasification project in Fall River.[80] The project's developer, EG&G, has recently submitted plans to the EFSC[81] and is awaiting approval from the U.S. SynFuels Corp. for loan guarantees. The plans for the EG&G Energy Park are in their initial phases (the scheduled completion date is 1989), but the Council encourages the Companies to continue to evaluate the merits of obtaining power from this alternative energy source in the future.

The Council strongly promotes the use of renewable resource powered capacity to supplant large-scale capacity and displace oil where such capacity is economically justified and environmentally acceptable. In that view, we direct the Companies to meet with Council staff and representatives of the Executive Office of Energy Resources to develop a more comprehensive and aggressive renewables and cogeneration supply plan. Supply Condition number 3 addresses this issue.

E. Canadian Energy

The Companies have entered into an agreement to purchase 25 MW of capacity from the Pt. LePreau deuterium-type nuclear power plant, starting in early 1983. The contract has been approved for the 1983-1991 time frame by the Canadian National Energy Board. The purchase comes at an opportune time for the Companies in light of the

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80 See COM/Electric Response to EFSC Staff Information Request SRAR-1 (item 18).

81 EG&G, New England Energy Park - Preliminary Long-Range Forecast, December, 1982.

difficulties with the Seabrook Units. The deuterium style Candu reactors have demonstrated a high degree of reliability and substantially lower cost power than new U.S. built light water cooled reactors,[82] and Pt. LePreau should be an advantageous addition to the Commonwealth supply plan. As was the case with other purchasers of this power that have come under Council review,[83] we support this purchase as it is needed to meet load growth.

The Companies also have under consideration the purchase of energy from Hydro-Quebec's large hydroelectric project in James Bay, Canada. The Companies are participating in these negotiations along with other members of NEPOOL. COM/Electric is considering an initial purchase of 30 MW of transmission capacity (in 1986 at the earliest) and a later purchase of 75 MW. The initial planning for this project contemplates energy interchange, although a number of important issues (i.e., contract terms, transmission-line approvals, price agreements) remain to be resolved. For the moment, therefore, the timing of the availability of Hydro-Quebec power to the Companies is uncertain. The Council will wait to carefully review this addition to the Companies' supply plan until the issue become ripe.

F. Conclusions: Supply Plan

COM/Electric has recognized that the events of the past decade have dramatically changed the principles of prudent utility system planning.

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82 See: Nuclear Energy Policy Study Group, Nuclear Power Issues and Choices (Cambridge, Mass.: Ballinger, 1977), pp. 395-396; Steve Thomas and John Surrey, "What Makes Nuclear Power Plants Break Down?" Technology Review, Vol. 83 No. 8, June 1981, 57-63. Also: COM/Electric Response to EFSC Staff Information Request SCR-1.

83 In Re MMWEC, 5 DOMSC 53 (1979), at 86, note 19; In Re Boston Edison, 7 DOMSC 93 (1982, at 149-153.

Such events as the cancellation of five planned nuclear facilities totalling 5750 MW, a dramatic reduction in the growth in demand for electricity due primarily to increased costs of oil and new plant construction, and environmental concerns about constructing large scale electric generating plans, have caused prudent companies to maximize the utilization of existing plant through economic load management, conservation, and renewable resource strategies. The Council has commended other electric utilities for this approach[84] and we commend COM/Electric here for its broad based, progressive beginning in this new approach to supply planning.

COM/Electric's supply plans identify a number of capacity additions the Companies intend to make to their current system in order to meet their forecasted capability responsibilities over the next decade. If all events happen as predicted, the Companies foresee adequate supply through 1990. But the Companies' own forecast of resources and requirements anticipates a capacity shortfall in the winter of 1991 -- even if every prospective supply addition (or proposed load reduction) comes on line exactly when scheduled.

In keeping with its statutory responsibility to "provide a necessary power supply for the Commonwealth at a minimum impact on the environment at the least cost,"[85] the Council cannot accept a deficiency in forecasted supply. The Council therefore orders the Companies to submit to the Council a plan for how they intend to meet their capabi-

84 In Re NEES, at 310, 317; In Re NU, at 58-63; In Re EUA, at 36-40; In Re Fitchburg, at 249-255 (also commending MMWEC).

85 M.G.L. c. 164, sec. 69H. See also In Re Boston Edison, at 146.

lity requirements for the winter of 1991-92. The second Supply Condition addresses this requirement.

The capacity shortfall could in fact occur sooner than 1991, depending upon whether the timetables of any of the major projects slip. The Council joins with the Companies in hoping that they do not, but we have serious doubts that all projects will come on line as projected. These doubts are particularly directed at the Seabrook units, and especially in the case of Unit 2, where the NRC has suggested that this unit may not be built.[86] But we are equally concerned with the timing of the SEMASS project, as the history of similar projects has been one of deferral and delay,[87] and the delivery of energy from Hydro Quebec is far from certain. We do not doubt, except possible for Seabrook Unit 2, that these projects will come on line, only that the Company's timetable is overly optimistic.

Therefore, we approve the supply plan as set forth in Table 8 subject to the attached Supply Conditions Number 1, 2, 3, and 4.

86 See In Re Fitchburg, at 250-253.

87 EOEA's Department of Environmental Management has yet to bring about the construction of such a plant after eight years of effort, even though it has a plan (Massachusetts Solid Waste Plan) and a enabling legislation to do. (M.G.L. c. 16, sec. 19).

Supply Conditions

1. That the Companies submit as part of their next filing a contingency plan for how they will meet their capacity responsibilities in the event that their proposed supply additions (especially Seabrook Units 1 and 2, SEMASS, and Hydro-Quebec) do not come on line on their currently scheduled dates. The Companies are also directed to file with the Council semi-annual reports on PSNH's progress on the two Seabrook Units.

2. That the Companies submit as part for their next filing a supply plan which is sufficient to cover projected peak demand and resources for all forecast years.

3. That the Companies' staff meet within 90 days with the staffs of the Council and the Executive Office of Energy Resources to: further develop and refine the Companies' plans to acquire either energy or capacity generated by renewable resources or co-generation; and discuss the range of load management techniques available to the Companies, as well as the Companies' plans for monitoring and analyzing the costs and effectiveness of alternative load management and conservation strategies.

4. That the Companies perform a cost-benefit analysis of all of their projected supply additions (including load management strategies, renewable resource projects, conservation, and cogeneration options) to show which of their programs will be most cost-effective over the life of the investment. The Companies will be expected to submit the results of this analysis as part of their next filing.

V. TECHNICAL ANALYSIS OF THE COMMONWEALTH MODEL

This section of the Decision provides a detailed analysis of each component of Commonwealth's demand methodology. The economic and demographic forecasts are first reviewed, followed by an analysis of the residential, commercial, industrial, price, and peak demand forecasts. Energy modeling is a "building block" process; therefore Commonwealth's methodology can only be effectively assessed by examining each block.In each case, the forecast methodology is described and critiqued, problematic components are addressed, suggestions for improvements are made, and in three instances Conditions are attached. The Demand Conditions and general methodological conclusions on Commonwealth's methodology have been previously outlined in Section VI.D of this Decision. The following technical analysis provides the basis for those conclusions, and offers a detailed look at the model's components.

A. The Methodology for Economic and Demographic Forecasts

The Economic/Demographic Module of the NEPOOL model generates forecasts of the principal components that drive the end-use oriented "Power" submodules for each sector.

1. Population

The model generates service area population forecasts using the cohort survival technique. This method tracks the distribution of the population through time (by age and sex) as impacted by annual births, deaths, net migration, immigration, and the aging process.[88]

Births are derived by trending age-specific birth rates experienced during 1979 in Commonwealth's service area so that they approach the

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88 Forecast, p. 1.4.13.

Massachusetts rates by the year 2000.[89] Projected death rates are based upon actual 1979 deaths for the service area and national mortality trends.[90] The aging process is simulated annually, by simply moving the population through each age. These standard techniques offer a systematic method for producing base population forecasts. As the 1980 disaggregated Census data become available, the trended components of these projections should be re-examined for current validity. It may be that, over time, Commonwealth will be able to discern service area demographic patterns (e.g., fertility rates) which vary from the long-term state and/or national trends adopted for long-run projections.

By far, the most volatile component of the population forecasts, and the most difficult to project, is service area migration. This component is also the most important part of the overall population forecast. Commonwealth's service area population grew by 109,527 from 1970 to 1980 (an increase of 33%), of which 98,355 (or 90% of this increase) was attributable to net migration.[91]

The Company predicts migration with the following equation:

$$M = a + b\,(U_{us} - U_{sa})$$

where:

M = adult migration by age and sex

U_{us} = national unemployment rate

U_{sa} = service area unemployment rate

Both the specification of this equation, and the estimates of the

89 Ibid. Massachusetts birth rates are predicted in NEPOOL's 4/1/81 solution.

90 Forecast, p. 1.4.13.

91 Forecast, p. 1.4.15.

parameters (a and b) cause concern to the Council, particularly in light of the obvious importance of these projections to the model as a whole. First, the method attempts to account for economic opportunity differentials between the service area and the nation, but it is not evident that these are the appropriate two regions to compare. Nor is it clear that relative unemployment rates explain relocation behavior. Considering Commonwealth's unique service territory, other factors may be operable, such as location preferences, or distance constraints on migration. BECo's analogous specification was criticized on similar grounds.[92] Furthermore, employment opportunities outside of Commonwealth's service area may affect migration to the area: Job opportunities outside of the immediate service area (Boston, etc.) may lead to in-migration in the service area, or vice versa.[93]

The second matter of concern is Commonwealth's use of NEPOOL's estimated parameters (a and b in the equation above), which were derived from cross-sectional data over 1960-1970 for six New England States.[94] There is no a priori rationale for assuming that these estimates are reasonable predictors for Commonwealth's service area. The Company has shown that the implemented version of this methodology follows estimated 1970-1979 net-migration fairly well, especially given the difficulty of the task, but the predictive ability of this version must be questioned in light of the previous discussion on this procedure.[95]

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92 See 7 DOMSC 93 (1982), at 115-116.

93 This phenomenon is taken up further in the analysis of Commonwealth's net-commuting adjustments.

94 NEPOOL documentation, op. cit., Chap. 8, p. 13, and COM/Electric's response to Staff Information Request COMD-2.

95 For model produced estimates, see Exhibit COMD-2b.

While the Council recognizes the complexity of predicting migratory behavior, we feel that the Company should endeavor to estimate its own model parameters and to experiment with specifications that incorporate a broader view of the migration decision, as discussed.

A final note on migration relates to the Company's separate method for predicting migration of the elderly population. Using an independent consultant's projections for Cape Cod elderly net-migration (which shows a projected decline from 600/year in 1980 to 200/year in 1990), the Company added a constant 776/year for the remainder of the service area (derived 1960-1980 average).[96] In this regard, the Company should investigate the reasonableness of projecting a steadily declining Cape Cod net migration while also assuming a constant level of elderly migration for the remainder of their service area. Secondly, the overall projected decline from 1376/year in 1980 down to 976/year in 1990 should be re-evaluated in light of the higher historic average (1,976/year), the national aging trend and the often-cited attractiveness of the greater Cape Cod area for retirees.

Net-commuting affects both the population and employment forecasts given the labor force-population equilibrium nature of the model.[97] The Company has commendably moved beyond the strict equilibrium framework through a net-commuting adjustment to reflect the effects of economic opportunities external to its service area. Thus, it allows for the interdependence of the local economy with surrounding economies. The Company has relied upon a trended 1970 Census "Journey to Work" study

96 See COM/Electric response to Staff Information Request COMD-4.

97 With this specification, it is assumed that the majority of the working age population will only stay in the service area if sufficient employment opportunities exist, thus the model assumes a population - labor force equilibrium, which has been altered by Commonwealth to account for commuting.

in its projection method. Commonwealth estimates that 19.74% of its service area's labor force out-commuted during 1982, which is trended down to 18.78% by 1991. In-commuters are assumed to remain a constant 6.35% of its labor force.[98] Given the obvious importance of these estimates to the economic/demographic balance of Commonwealth's service area, the Company is strongly encouraged to re-evaluate the commuting estimates when 1980 Census data are available, and to investigate a methodology which attempts to capture the causal relationships behind commuting patterns in and out of its service area.

Immigration was forecast based on the average number of immigrants (842) recorded for New Bedford over the 1960-1970 and 1973-1979 periods. (Springfield, Worcester, Boston, and Cambridge are the only other cities in Massachusetts for which these data are available.) Given no apparent trends in the data (they range from 245/year to 1773/year), this is a reasonable projection method.[99]

2. Households

The number of households is an important input variable to the residential forecast. It is forecast by applying age and sex-specific headship (or household formation) rates to the population.[100] The headship rates are from 1970 Census service area data, and are trended through time according to national estimates.

The aggregate household forecast is broken down by type of home, based on the 1970 Census data, and adjusted through 1980 according to

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98 Forecast, p. 1.4.32, and COM/Electric response to Staff Information Request COMD-10.

99 For the data, see COM/Electric response to Staff Information Request COMD-5.

100 Headship is defined as the percentage of a particular age and sex group that are heads of households, see Forecast, p. 1.4.19.

building permits issued over the period. The resulting breakdown, as follows, is assumed to remain constant over the forecast period.[101]

Single homes	69.8%
Multiple homes	29.4%
Mobile homes	0.8%

Second homes are forecast as a decreasing percentage of total homes based on Census data, company records, and a consultant's report.[102]

These methods seem reasonable given the data available to the Company. The Company is encouraged to review the 1980 Census data to cross-check the accuracy of these assumptions.

3. Income

Commonwealth projects income within the NEPOOL model framework, but uses the results only in estimating the appliance saturation of air-conditioners. Given this limited use, the income projection mechanism is not analyzed in detail here.

However, the Counci is seriously concerned that the effects of changing income levels have been delegated to such a minor role in the residential forecast. The Council expects that an expanded use of income, or adequate evidence supporting its continued absence, will accompany future Commonwealth forecasts.

4. Labor Force

The service area civilian labor force is defined as people employed or actively seeking employment. Specific labor force participation rates are applied to population groups (broken down by age and sex) to yield an estimated labor force. The difference between the estimated

101 Forecast, p. 1.4.19.
102 Ibid.

labor force and employment is unemployment, which as the model stands now is key predictor of migration.[103]

The partipation rates were estimated for each age and sex group with the following specification:

$$\text{Labor Force Participation Rate} = a + b \frac{\text{Total Employment}}{\text{working age pop.}} + c \quad \text{Time}$$

This equation is a simple but reasonable working expression and was estimated by NEPOOL for Massachusetts (and the other New England States) using 1960 and 1970 Census data.[104] Commonwealth utilized the NEPOOL estimated Massachusetts parameters for the historical simulation and relied upon NEPOOL's trends toward national participation rates over the forecast period.[105] The Company should re-examine the accuracy of the Massachusetts parameters for its service area with the 1980 Census data.

The NEPOOL method for projecting the labor force projections is a trending toward the Bureau of Labor Statistics national projections.[106] The Company is again encouraged to compare the validity of this assumption with historical experience to verify that service area labor force characteristics do not exhibit a long-run deviation from national trends.

103 NEPOOL Documentation, op. cit, Chap. 8, pp. 18-19.
104 Ibid.
105 Forecast, p. 1.4.17.
106 NEPOOL documentation, op. cit, Chap. 8, p. 19.

5. Employment - Total

The importance of the employment forecasts to the ultimate energy forecasts is matched only by the difficulty associated with their projection. Employment is a direct input to the commercial energy forecast, an indirect input to the industrial energy forecast through value added, and an indirect input to the residential energy forecast through migration effects on population.

Commonwealth has relied upon a "hybrid" methodology for forecasting employment. It consists of time trends, judgment and regression analysis depending on the individual industry being forecast. Total service area employment by place of work in 1970 was developed from the Census "Employment by Place of Residence" data and combined with "Journey to Work" data to account for commuters. Manufacturing employment by SIC was taken from the "covered" employment data published by the Massachusetts Division of Employment Security (DES). Non-Manufacturing employment was taken to be total employment less manufacturing employment because the DES "covered" employment data excludes many small firms,[107] which is not a problem with the manufacturing data. DES and County Business Patterns data were used, however, to distribute the derived non-manufacturing total across SIC categories.[108]

6. Manufacturing Employment Forecasts

Commonwealth first experimented with two forecasting logics. The first was to relate service area manufacturing employment by two-digit SIC to state employment by SIC in the linear form:

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107 Bureau of Labor Statistics regulations require that employment security data not be released if there are less than 3 employees in one area or if one industry represents more than 80% of a classification.

108 See Forecast, pp. 1.4.21-22 and COM/Electric response to Staff Information Request COMD-11.

$$\text{Commonwealth Employment (SIC)} = a + b\left(\text{State Employment (SIC)}\right)$$

The Company found these results satisfactory for eight of the nineteen two-digit SIC's projected. The Company then experimented with an alternative explanatory variable -- national GNP -- under the assumption that local manufacturers may be producing for a national market. The results proved statistically unsatisfactory. Presumably as a last resort, the Company adopted a time trend for one SIC and relied on judgement for the remaining ten categories. Table 9 presents each SIC forecasted, the method chosen, the predicted average annual growth rate, and the percentage of Commonwealth's total industrial sales for each SIC in 1980.

The table shows that two SIC's are projected to experience negative growth, seven are projected at constant levels, and the remaining ten are projected at increasing levels for an average annual compound growth of 0.2%. One-half (51.2%) of Commonwealth's 1980 industrial sales are attributable to SIC's where regression analysis was used as the projection method. The remaining SIC's were projected relying on the Company judgment and historical experience. On the surface, the forecasts appear reasonable. Where judgements were relied upon, the Company presented supporting dialogue which indicated a good working knowledge of the industry in its service area.[109] The Council understands the difficulty of forecasting service area employment, and recognizes the need for subjective input. We encourage the Company to continue its efforts to use quantitative projection methods, and where these fail, to continue to document its more judgmental assumptions.

109 _Ibid._, pp. 1.4.26-29.

Table 9

Commonwealth Industrial Employment Forecasts

SIC	Forecast Method[1]	Predicted 1981-91[2] Avg. Ann. Growth	% Industrial[3] Sales, 1980
20 Food	judgment	1.5	9.5
22 Textiles	regression	(1.98)	13.3
23 Apparel	regression	.20	5.4
24 Lumber & Wood	judgment	0.0	.7
25 Furniture	judgment	0.0	.05
26 Paper	regression	.73	.7
27 Printing	judgment	0.0	2.5
28 Chemicals	judgment	0.0	1.5
29 Petroleum	judgment	0.0	.03
30 Rubber & Plastics	regression	(1.23)	5.5
31 Leather	regression	.45	.5
32 Stone, Clay, Glass	regression-time trend	2.92	.8
33 Primary Metals	judgment	.48	9.6
34 Fabricated Metals	judgment	1.08	12.3
35 Nonelectric Machinery	regression	.89	6.4
36 Electrical Machinery	regression	.19	9.7
37 Transportation	judgment	0.0	1.4
38 Instruments	regression	.50	9.6
39 Miscellaneous Man.	judgment	0.0	10.4
Average		.20	

1,3: Forecast, pp. 1.4.25-29.
2: COM/Electric Response to Staff Information Request COMI-1.

In this area the Company has shown that judgmental forecasts, when properly documented, can be an acceptable component of an overall rigorous approach.

7. Non-Manufacturing Employment Forecasts

"Non-manufacturing employment is forecast as a function of population based on the assumption that non-manufacturing employment expands to meet the needs of a growing population."[110] Ratios of employment (by one-digit SIC) per one-thousand population were developed using 1970 Census data, trended through 1980 using available data, and trended over the forecast period based on judgement and/or NEPOOL's projections for Massachusetts. Applying these ratios to projected population totals yields projected non-manufacturing employment by SIC.

Table 10 shows for each employment category the method used to forecast the employment-to-population ratio, the predicted average annual growth rate, and the percentage of Company sales (1980) attributable to each employment category. In each case, the projections for the ratio of employment per thousand population determine the actual employment levels projected. As indicated in the second column, these methods ranged from judgment to time trends to adoption of the Massachusetts trends predicted by NEPOOL.

On the surface the forecasts appear reasonable, especially considering the high growth rates experienced over the past decade in Commonwealth's service area.[111] Based on the magnitude of the Company's sales to the wholesale, retail, and services commercial categories, the

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110 Ibid., p. 1.4.29.

111 For example, 1970-80 growth in wholesale/retail sales averaged 4.35% per year. See COM/Electric's response to Staff Information Request COMC-9.

Table 10

Commonwealth Commercial Employment Forecasts

SIC	Forecast Method[1]	Predicted 1981-92[2] Avg. Ann. Growth	% Commercial[3] Sales, 1980
01 Ag, Forestry, Fishing	assumed constant ratio	1.61	.3
10 Mining	assumed constant ratio	1.60	.1
15 Construction	adopted NEPOOL's trend for Mass.	1.33	1.0
40 Transp. & Public Utilities	time trend	3.22	8.3
50 Wholesale & Retail	time trend	2.46	40.5
60 Fiannce, Ins., Real Estate	adopted NEPOOL's trend for Mass.	2.81	7.3
70 Services	time trend	2.99	32.0
90 Government	assumed constant ratio	1.61	10.5
Average		2.40	

1. Forecast, pp. 1.4.29-31.
2. Ibid., Calculated from data pp. 1.4.95-96.
3. Letter from Company dated 1/11/83.

Company should continue to attempt to refine its predictive methods for these SIC's.

A final methodological point concerns the appropriateness of basing the forecasts of such "resource based" employment as agriculture, forestry, fishing, and mining solely on population trends. Although these categories represent a very small portion of the Company's sales, alternative methods should be investigated.

Lastly, the Company has indicated that it has reviewed Massachusetts employment forecasts from NEPOOL, the Bureau of Economic Analysis, and the D.E.S. in its employment projection process.[112] The Company should continue to monitor these alternative forecasts so that the service area forecasts may be checked for their reasonableness in comparison to these other projections.

B. <u>The Residential Forecast Methodology</u>

The basic approach in the residential sector is to break aggregate demand down into its components (energy use by appliance). The end-use specification is simply stated as:[113]

$$\begin{array}{c} \text{Demand at} \\ \text{a given hour} \\ \text{by appliance} \end{array} = \begin{array}{c} \text{Number of} \\ \text{Appliances} \end{array} \times \begin{array}{c} \text{Connected Load} \\ \text{of Appliance} \\ \text{(wattage)} \end{array} \times \begin{array}{c} \text{Fraction of Connec-} \\ \text{ted Load Operating} \\ \text{(use pattern)} \end{array}$$

When summed across appliances, this expression yields forecasts of residential energy and loads. This end-use methodology is particularly powerful in that, when accompanied by quality data, the Company can analyze a variety of load management, load shifting, and conservation measures and predict their overall effects on the system. The Company can also predict the effects of shifting appliance numbers and usage

112 See Exhibit COMD-12.
113 Forecast, p. 1.4.44.

patterns.

The initial aspects of reviewing the end-use method include the issues of the quality of the historical data and the methods by which they are projected. These issues are discussed for each component of the residential end-use equation.

1. Number of Appliances

Commonwealth has taken the first major step toward gaining a comprehensive knowledge of its residential demand through the implementation of an appliance saturation survey. The surveys were conducted in 1979, 1980 and 1981. The 1979 survey data have been prepared and used a as a benchmark for the Company's forecasts.[114] The information from the surveys of appliance saturation and ownership determinants have proved to be an essential component of the residential forecasts. The Council commends the Company for undertaking this data collection effort, and expects that subsequent surveys will enhance this information base by allowing the Company to investigate causal realtionships behind appliance saturation trends.

Saturations were projected using a variety of methods, including judgement, econometric equations, and NEPOOL projections. With saturation defined as the percentage of homes having a particular appliance, the product of these saturation estimates and projected households yields estimated appliance stock projections. The projected 1982 and 1991 saturations and the projection method (or determinants) used for each appliance are shown in Table 11.

The implications of these saturation projections for supply planning cannot be understated, as they depict a continued "electrification"

114 See Exhibit DOC-2(a), "1979 Residential Appliance Saturation Survey."

Table 11

Commonwealth Projected Residential[1]
Appliance Saturations

Appliance	1982	1990	Method/Determinants
Range	55.5%	64.9%	age of home
Refrig., FF.	82.1	85.5	age of home
Refrig., Std.	39.1	34.8	age of home
Freezer, FF.	6.4	8.6	assumed constant in total
Freezer, Std.	15.1	13.0	assumed constant in total
Dishwasher	51.0	63.3	age of home
Washer	77.5	77.5	assumed constant
Dryer	55.9	63.3	age of home
Water Htr., Ctrld.[2]	9.6	7.4	assumed to capture 100% of
Water Htr., Uncntrld.[2]	14.3	21.0	electrically heated homes, and constant lower share of others.
Microwave	12.0	48.1	NEPOOL time trend
TV, Color	96.2	114.8	assumed constant in total
TV, B&W	59.0	40.3	assumed constant in total
Lighting	100.0	100.0	assumed constant
Misc.	100.0	100.0	assumed constant
AC/Room	29.3	34.2	income functions
AC/Central	1.9	2.3	income functions
Heating	10.3	15.3	penetration function
Fossil Auxiliary	89.7	84.7	reciprocal of heating
Second Homes[3]	31.2	30.0	time trend
Wood Stoves[4]	*	*	assumed constant[4]

1. From Forecast, p. 1.4.119 and p. 1.4.47-52.
2. The split between controlled and uncontrolled is forecast to favor uncontrolled due to the assumption of a constant number of uncontrolled with an increasing number of households.
3. Energy use by seasonal homes is modeled in aggregate and not by appliance, thus the saturation represents the share of total homes.
4. Wood stoves are assumed to saturate electric homes at 20%, and reduce average electric space heating use by 34%.

of the home. Commonwealth is projecting (at least in the aggregate for each appliance type) constant or steadily increasing saturation levels for all appliances. The fact that households are projected to increase by 26% over the 1982-91 period (or 2.6% per year), combined with constant or increasing saturations in both old and new homes, leads to Commonwealth's prediction for residential demand to increase at the robust rate of 3.1% per year, -- a rate matched only by the industrial forecast.[115]

The Council will not endeavor to discuss and critique each methodology used to forecast saturations, but we will spell out a few troublesome areas where there appears to be room for improvement. We expect that saturation surveys over time, will prove to be the best support for a reliable appliance forecast.

Appliance	Suggestion
range, dishwasher, dryer	re-evaluate assumption that saturations in old homes will equal those in new homes by the year 2000.
air conditioner	estimate own-vs.-NEPOOL's income functions.
space heating	include price and availability of gas in penetration function.
wood stoves	evaluate stove-caused reduction in average heating use based on actual customer data.
water heating	attempt to develop Company-specific projection mechanism.

Understanding the complexity of the tasks, the Council believes the Company has thus far made a credible first attempt at the process. Given the high usage levels of these particular appliances, further developmental work on these projections will be well directed.

115 Forecast, p. 1.4.3.

2. Connected Load

The second piece of information in the Residential end-use equation is connected load per appliance, measured in watts. "Connected load data in the Commonwealth model for individual appliances was assembled by NEPOOL from: (1) national averages prepared by the Edison Electric Institute, from load studies conducted by members of the AEIC (Association of Edison Illuminating Companies) and (2) data provided by NEPOOL member companies."[116]

The Council recognizes the critical lack of service territory data on appliance connected loads, and does not fault the Company for making use of these data, per se. We do, however, raise questions concerning the methods used to adjust these data to its service area. These issues are addressed under the next topic of appliance use profiles because these two pieces of information, and the resulting issues cannot be entirely separated.

Because the connected load data and hourly use profiles are combined in a multiplicative form in the model, certain factors which may effect either load or use were not partitioned (e.g., price elasticities, appliance efficiency improvements). Given the structure of the model the Council concurs with this treatment as long as the Company's assumption of uniform effects across all hours holds true.

The following factors are accounted for in the NEPOOL model to reflect conservation, households size, and interactions between appliances:[117]

116 Forecast, p. 1.4.53.
117 Price is dealt with separately in a later section.

°Mandated efficiency standards: The Commonwealth model incorporates the assumption of federally mandated appliance efficiency standards and their effects on connected loads over time with an appliance stock model. These adjustments can no longer be substantiated on the assumption of a federal mandate, as none is forthcoming. This is a progressive attempt to model efficiency improvements, and should not be abandoned, but should be re-evaluated in terms of the current federal policy and laws and their projected effects.

°Household size effect: Certain appliances (e.g., electric range, microwave, refrigerator, washer, dryer, and water heaters), are modeled as sensitive to household size. The Company has adopted NEPOOL's estimated (based on national data) using the Company's estimates household size in 1970. The Company should investigate the applicability of these parameters for its service area, and the static nature of the calibration, but we applaud the overall concept.

°Dishwasher effect on water heating: The combined effects of dishwasher and water heater load are importantly recognized.

°Water heating conservation: A service-area-specific trend was forecast for water heating conservation, which goes beyond the price effect. The Council praises the Company's efforts here.

°Microwave effect on electric range: This accounts for reduced total energy use for cooking in home with both appliances. While the supporting study does not appear to be a rigorous treatment, we support the inclusion of this interactive effect.

3. Fraction of Connected Load Operating (Use Profiles)

These data, which represent the third component of the residential equation, capture the use of weather-sensitive and non-weather-sensitive appliances according to time of day or temperature. The data, called "load" or "use" profiles, express the probability that a certain appliance will be operating during a given hour or temperature condition.

For non-weather-sensitive appliances, the use factors are dimensioned by day,[118] hour, and month. Thus, each end-use has a corresponding use profile matrix with 1152 elements. For weather sensitive end-uses, the month is replaced by a temperature probability profile. Commonwealth has used the profile developed by NEPOOL for the Boston weather station, which appears reasonable in light of comparable degree days for the service area and Boston.[119]

Of critical importance in this type of detailed end-use modeling is the quality of the data used to construct the use profiles. The use profiles, integrated over the connected load information, yield energy use by appliance and are summed to yield the residential forecast.

Commonwealth has utilized NEPOOL's estimated use profiles which were garnered from a variety of sources. The data is discussed separately for weather, and non-weather, sensitive appliances.

Table 12 summarizes the data sources and study characteristics used

118 Actually four "day types": Monday; Tuesday-Friday; Saturday-Sunday; and holidays.

119 See Forecast, p. 1.4.45. Average total degree days for Commonwealth and Boston over 1952-1980 were 5797 and 5752 respectively.

TABLE 12*

RESIDENTIAL SECTOR APPLIANCE USE PATTERNS

STUDY SOURCES

Appliance Type	Source	Date of Study	Geographical Area	Sample Definition	Test Period
Freezer-Frost Free & Std.	AEIC, 1960-61, Pg. 91, Potomac Electric Power Co.	1959-60	Washington D.C.	39 customers with standard freezers	Aug.-Sept. 1959 & Jan.-Feb. 1960
Refrigerator/Freezer-Frost Free & Standard	AEIC, 1966-67, Pg. L-95, Baltimore Gas & Electric Co.	1966	Baltimore, Md.	33 single family dwellings with frost-free units. Ave. home=5 rooms, occupancy=3.4 persons	12 mo. ended November 1966
Range & Microwave	AEIC, 1968-69, Pg. L-11, Baltimore Gas & Electric Co.	1966	Baltimore, Md.	33 single family dwellings Ave. home=6 rooms; occupancy=4.5 persons	12 mo. ended June 30, 1966
Residential Lighting	AEIC, 1960-61 (Pg. 105) & 1961-62 (Pg.147) Nat'l Survey of Residential Lighting Loads	1960-62	22 locations in U.S.	124 customers served by 22 utilities. Predominantly owner-occupied, single family dwellings	Nine-2 wk. periods, during an annual period 1957-58.
Television-Color & B&W	AEIC, 1973-74, Pg. L-101, Pacific Gas & Electric Co.	1974	Sev. sec. U.S.	200 cross-sectional households	Oct. 1972 - Jan. 1974
	AEIC, 1959-60, Pg. 114 Potomac Electric Power Co.	1958	Washington D.C.	40 customers	2 wks., March-April 1958, 2 wks., August 1958
Clothes Washer	AEIC, 1957-58, Pgs., 130, 139-141, Texas Utilities Co.	1958	North-eastern Texas	77 residential customers	Several 12 mo. tests between 6/55 & 3/57.
Clothes Dryer	AEIC, 1969-70, Pg. L-104, Baltimore Gas & Electric Co.	1969	Baltimore, Md.	33 homes; Ave. Occupancy of 4.3 persons	Nov., 1967 - Oct., 1968
Dishwasher	AEIC, 1957-58, Pg. 131; 141, 142	1955-57	Dallas, Texas	15 Customers	Feb., 1956 - Jan., 1957
Water Heater (Uncontrolled)	AEIC, 1969-70, Pg. L-144, Detroit Edison Co.	1969	Detroit, Michigan	65 50-gal. and 66 80-gal heaters randomly selected; Ave. family size = 3.7 persons	12 month ended November, 1969
Water Heater (Controlled)	Northeast Utilities	1981	-	Estimated values to reflect desired time clock settings	-
Water Heater (Storage)	NEPLAN	1981	-	Estimated values to reflect long term storage capability of large tanks	-

*Taken from the NEPOOL Model Documentation, Tech. Chap 6, "Use Profiles", October, 1982 to develop the use profiles. NEPOOL, in its documentation, offers the following description of the data:[120]

> "As shown, for the most part load research studies reported by the Association of Edison Illuminating Companies (AEIC) served as the data source. Although these studies did not originate from a single data base, i.e., they were not all collected at the same time or place with one data collection program, they are considered to be useful and adequate.
>
> For several of the appliances shown in Exhibit 5, average daily KWH consumption per appliance was available for each of the four day types and the twelve months. For others, daily use was only available for two day types and/or for only specific months of the year. For most of the appliances, daily load profiles were available for summer and winter seasons and in a few cases for each month of the year."

The Council has several problems with the use of these data for Commonwealth's service area. First, much of the data arises from studies in the 1950's and early 1960's. Since that time major socio-economic changes have taken place in the home (e.g., the emergence of the "two-income home") which may have resulted in substantial changes in appliance use.

Secondly, the geographic distribution of the studies falls predominantly outside of the New England region. The geographical homogeneity of appliance use may be a proper assumption for some appliances (such as lighting), but is less certain for other appliances where factors such as local work patterns (as in an industrial area where work shifts predominate) may affect the timing, level, and duration of appliance use.

Lastly, the demographic characteristics found in the household studies can be seen to vary markedly from those in Commonwealth's area.

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120 NEPOOL documentation, op. cit, Chap. 6, p. 10.

For example, the range and microwave study included homes of an average occupancy of 4.5 persons; for dryers, it was 4.3 persons. Commonwealth estimates its service area has an average household occupancy of 2.7 persons in 1982.[121] The household size effect in the model attempts to account for the overall change in annual KWH use, but it is not clear that the data from these studies have been (or can be) properly adjusted or whether the timing of appliance use would remain unchanged.

The weather-sensitive use profiles for space heating (uncontrolled) were developed from a study[122] in Amherst, Mass. (1971-1973) and for storage heating from a study[123] in Vermont (1978-1979). For residential air conditioning, a study[124] in Connecticut (1974-75) was utilized. The use of these data is less problematic for the Council given the timing and location of the studies.

The Company relied on these data initially, then used a calibration procedure that involved simulating 1970-80 actual residential sales, and then adjusted the data so as to minimize the historical predictive error. This procedure assumes that whatever combination of forces caused the data to err in the past will exhibit the same effect in the future. On the surface, this assumption lacks credence, given there is not evidence to support the applicability of the data for Commonwealth's service area.

There is at least preliminary evidence that the aggregate error may not be very time sensitive. The Company has indicated that the "level adjustments" required for the historical simulation years of 1970 and

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121 Forecast, p.1.4.3.
122 NEPOOL documentation, op. cit, Chap. 6, p. 35.
123 Ibid., p. 40.
124 Ibid., p. 50.

1980 were of a similar magnitude. However, the Company did not report the magnitude of the required adjustments. Given the Council's present concerns, the Company should report these and similar results in future filings.

Table 13 presents a comparison of average annual use for major appliances from several sources: Commonwealth's 1979 estimates in the model; estimates indicated by a conditional demand analysis conducted for Commonwealth with its 1979 Saturation Survey; and seven other sources. The table shows that estimates for average use exhibit a considerable degree of variability. The variability, as might be expected, is most pronounced for the weather sensitive appliances. Other factors likely to influence variability in estimation are the diversity of use, demographic and geograpahic factors, and the research method. The Company, in supplying the Council with the conditional demand analysis that accompanied its 1979 Survey, asserts that this represents "a major verification of the Commonwealth Model data."[125]

On the basis of a brief review of the demand analyses, the Council makes the following observation: The demand analyses, as asserted by the Company, indicate that the model's data fall within the 95% confidence intervals estimated around each appliance's use per year. But the 95% confidence intervals themselves incorporate such wide bands that this, in and of itself, does not instill confidence in the averages used in the model. (For example, the 95% confidence interval indicated for electric ranges is 675 -1404 kwh/year which includes all nine estimates for average use.) The model's average use estimates do not appear

125 Letter from Company dated Jan. 5, 1983.

Table 13

Comparison of Estimated Annual Appliance Use (KWH) from Various Sources

iance	Commonwealth[2] Model	Commonwealth[2] Cond. Demand Analysis	EPRI[2] Cond. Demand Analysis	EPRI[2] Engineering Studies	Merchandising[3] Week	Potomac[3] Electric	University[3] Illinois	Electric[3] Energy Associates	Midwest[3] Research Institute
ge	938	1040	775	1177	2071	1225	1210	1175	782
igerator[1]	1248	1096	1197	1409	1228	1330	1210	1137	1665
zer[1]	1203	1459	1219	1404	1480	1560	1210	1195	1342
washer	338		599	281	363	340	378	363	149
ier	86			87	90	65	98	76	88
er	958	1199	1139	991	993	1100	980	993	1032
er Heater	4009		3396	4219	4515	5400	4233	4219	4046
, Color	547	707	622	455	502	450		660	
, B&W	350	243	209	250	362	345		350	
Room	403	275	1389	1265					978
Central	952								3573
ce Heating	8296	7925							2558

The figures reported here are not consistent for Frost Free, standard, average, or similar-sized refrigerators and freezers, so they are only useful for purposes of broad comparison.
From letter from COM/Electric dated Jan. 5, 1983.
From "Patterns of Electric Energy Use by Electric Appliances," EPRI Publication EA-682, Jan. 1979, pp. 5-23 and p. B-14.

demonstratably suitable for the Commonwealth service area, especially considering the characteristics that surround these studies. The Company should avail itself of the existing load research date before committing itself to the NEPOOL data base.[126] The Company should consider the applicability of available data based on:[127]

1. the similarities and differences between Commonwealth's service area's customers and those in the source utility's
2. climatic similarities and differences
3. date of study
4. credibility of study

After completing this search, the Company (and the Council) will be in a better position to judge the merits of the current data base versus alternatives. The Council, again, recognizes the paucity of existing quality load data, but it has not been demonstrated that the NEPOOL load data optimizes the use of the available load research for Commonwealth.

Prior to encouraging the Company to pursue more costly routes (such as conducting household surveys costing approximately 90 cents per customer or demand sub-metering, at approximately $464 per customer[128]), we direct the Company in demand Condition number 2 to perform an in-depth literature search, and to submit with its next filing a justification for the use of the NEPOOL data in light of that search.

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126 EPRI's "Patterns of Energy Use by Electric Appliances" (EPRI EA-682, Jan. 1979) contains a very good summary of residential studies as a starting point.

127 See: "Data Transfers Among Electric Utilities", Public Utilities Fortnightly, (April 29, 1982, p. 35-42) for a good discussion on the transferability of load data from one utility (or source) to another.

128 Larry E. Lewis, "Behavioral Energy Modeling", Consumers Power Company, Jackson, MI, paper presented to the International Association of Energy Economists, November, 1982, Denver, Colorado.

C. The Commercial Forecast Methodology

Commercial energy consumption is forecast using the same basic approach as in the Residential sector, except that the end-uses are limited to five, and are applied across each of seven employment categories. Again, we laud the Company's efforts at adopting an end-use methodology which should eventually provide the Company with a good working knowledge of the nature of its commercial demand and with greater supply planning flexibility.

Annual energy consumption for each end-use and commercial employment category are forecast as a function of:

$$\text{consumption} = f\begin{pmatrix}\text{commercial} & \text{annual} & \text{saturation} \\ \text{employment;} & \text{KWH/employee;} & \text{of end use}\end{pmatrix}$$

The development of the employment forecasts has been discussed previously, so we now concentrate on the latter two components in the equation.

1. Annual KWH/Employee Estimates

The key determinant of commercial use is the level of energy intensiveness, expressed in KWH/employee, by end use. These estimates are developed separately for weather, and non-weather (base-load), sensitive end-uses.

KWH/employee estimates have been derived from commercial surveys conducted by NEPOOL. The data collection programs involved personal interviews with 196 retail customers in Maine (in 1976) and 161 non-retail customers in Connecticut (in 1977).[129]

129 The actual breakdown was: building materials and hardware stores (17); general merchandise stores (21); food stores (39); automotive dealers and service stations (43); apparel and accessory stores (21); furniture stores (12); eating and drinking places (23); misc. retail (20); and for non-retail: Wholesale (19); banking (21); Ins. & R.E. (25); hotels (7); amusement & rec. (13); health services (17); education (28); gov't and other services (31). See NEPOOL documentation, op. cit, Tech. Chap. 3, p. 8 and p. 17.

<u>The nature of these studies and the resulting data raise serious questions as to their value in reliably disaggregating Commonwealth's commercial demand</u>. It is the data, however, and not the methodology that again cause concern.

The Maine and Connecticut data were regressed against economic, physical, and behavioral variables by NEPOOL's staff in an attempt to explain KWH/employee for the various employment categories. The sample sizes in the non-retail study "were statistically insufficient to provide representative estimates" for base load KWH/employee.[130] They were used only to provide "generally derived... representative estimates" for the temperature sensitive (kwh/degree day) estimates.[131]

As a result, "the retail trade study results were also used to estimate base load values for the other commercial sectors."[132] Thus, the base load kwh/employee estimates for retail stores are also assumed to apply to:

° Construction, forestry, fishing, agriculture

° Transportation and public utilities

° Wholesale trade

° Finance, Insurance, Real Estate

° Services

° Government and military

The Company has recognized the tenuous nature of this assumption. "The Company does have some concerns regarding the application of results from a retail trade survey to other commercial categories. For example, scaling factors relating total KWH/employee by commercial category to the level of retail trade were used to calculate base load kwh/employee

130 NEPOOL documentation, <u>op. cit</u>, Tech. Chap. 3, p. 17.
131 <u>Ibid</u>.
132 <u>Ibid</u>.

by category. This was accomplished by simply multiplying these scaling factors by the retail trade base load kwh/employee values."[133] Commonwealth also recognizes "hotels and motels, which are an important component of the service sector in the Commonwealth territory are simply not included in the survey used by NEPOOL to estimate base load kwh/employee."[134]

The Council and Company agree in principle on the need for improvement in the kwh/employee estimates for the non-retail employment categories, and we direct demand side condition number 4 toward an investigation into this matter. Specifically, the Company is directed to perform a literature search on commercial energy intensiveness, and to evaluate and justify the use of the NEPOOL estimates in light of this information.

In terms of projecting base load kwh/employee, the Company assumes no change, other than price induced, will occur. The Company supports this assumption based on the following: "In recent years, it appears that significant declines in base load kwh/employee have actually occurred. However, because lighting load represents approximately 80% of commercial base load use, and there is a very definite limit to conservation potential in this area, further non-price related declines in base load kwh/employee are not anticipated."[135]

The Council takes issue with this assumption without further evidence to support it. Recent years have seen an emergence of many devices on the market which claim to offer substantial energy savings in commercial lighting loads (e.g., movement sensitive light switches which

133 Response to Staff Information Requests COMC-2 and 3.
134 Ibid.
135 Forecast, p. 1.4.59.

selectively light office areas only when they are being utilized, and bulbs which offer greater efficiencies than traditional flourescent fixtures). The Council is not in a position to predict the market penetration of such devices, but we expect in future filings that such broad based assumptions will be supported with further evidence.

Base load projections are disaggregated into lighting and miscellaneous uses. Miscellaneous includes water heating, refrigeration, cooking, and "other". The estimated split of base load into these categories is based on a national study from Oak Ridge National Laboratory.[136]

Weather-sensitive load (electric space heating, fossil heating auxiliaries, and air conditioning) estimates have been derived from the aforementioned NEPOOL studies. The kwh/degree day/employee relationships have been derived from the studies in the following way:[137]

Study	Employment Category applied to
Retail Study (Maine)	- Retail trade - Construction, Forestry, Fishing, Agriculture, Mining - Transportation, Communications and Public Utilities
Non-Retail Study (Connecticut)	- Wholesale Trade - Finance, Insurance, Real Estate - Services - Government and military

This procedure is not nearly as problematic as the base load kwh/employee estimates due to the inclusion of an additional sample which covers non-retail customers. Given the predominance of the retail,

136 Jackson, J.R., and Johnson, W.S., Commercial Energy Use: A Disaggregation by Fuel, Building type, and End Use, ORNL/CON-14, Feb., 1978.

137 NEPOOL documentation, op. cit, Tech. Chap. 3, p. 13, 16.

wholesale, and services categories in terms of Commonwealth's commercial sales, reliable data on these categories is particularly important.

In implementing the NEPOOL derived estimates of base load and weather sensitive kwh per employee, the Company simulated the 1978-1980 period using the NEPOOL "Massachusetts level adjustment"[138] with the following results:[139]

Employment Category	KWH/employee (1980) Model	Actual	% Error
Const., Forestry, Fish, AG., Mining	1282	1101	16%
Transp. and Public Utilities	6076	7487	-19%
Wholesale	3906	2985	31%
Retail	8689	6721	29%
Finance, Ins., R.E.	3697	6682	-15%
Services	4262	8430	-49%
Government	4450	3608	21%

The results show the model performed most poorly for services, wholesale, and retail -- the three largest commercial customer categories in Commonwealth's service area. This is after a Massachusetts adjustment has been made to the original NEPOOL estimates, so presumably the unadjusted estimates derived from the NEPOOL studies would have performed even more poorly.

The Company has adjusted the Massachusetts parameters so as to produce actual 1980 commercial sales by employment category. These adjustments were made in aggregate, not separating base load from weather sensitive load. Further experience with the model should indicate the reliability of this procedure. At this time we have concerns that these estimates, adjusted around one-years sales, may fail to capture the more dynamic aspects of commercial energy use over time.

138 NEPOOL follows a similar procedure to Commonwealth implements the model for each state. First, historical simulation is conducted for each state using initial data and parameter values. Then adjustements are made to improve the historical performance which are assumed to hold true over the forecast period.

139 COM/Electric Response to Staff Information Request COMC 2-3.

We recognize the commercial sector energy data is probably the weakest link in all energy models at this time. We commend the Company for making a credible attempt at utilizing existing commercial data, but we are not convinced, as with the residential sector, that the Company has optimized the use of existing data. In response to Condition No. 4, we expect the Companies investigation into this issue to further the Company's progress in commercial forecasting.

2. Commercial End-Use Saturations

The Company's treatment of end-use saturation in the commercial model is not entirely clear in the Forecast, and the functional relationships between end-use saturation and the demand projections is not clear in either the Forecast or the NEPOOL documentation.

The Company projected end-use saturations for commercial electric space heating and air-conditioning. Commonwealth estimates that space heating saturation was 3% in 1980, which was time-trended to reach 4.7% over the forecast period.[140]

Air-conditioning saturation in the commercial sector has been estimated by NEPOOL at 50% for 1970 in the three southern New England States. NEPOOL projects a constant increase of 1% per year from 1970 beyond. The Company has also adopted this assumption.[141]

The Company has indicated in response to a question which asked

140 Forecast, p. 1.4.60.
141 Ibid.

why commercial energy growth was forecast to outpace commercial employment growth, that: "annual kwh per commercial employee is forecast to increase for all commercial categories. This anticipated increase is the result of forecasted declines in commercial electricity price and slight increases in electric space heating and air conditioning saturation."[142]

Given the apparent significance of commercial end-use saturation estimates, we therefore ask the Company to clarify its documentation on the linkages between saturations and kwh/employee in future filings.

3. Commercial Hourly Demand Profiles

The Commercial methodology calculates and then distributes annual consumption back across months, days, and hours according to a class load profile. This is in contrast to the residential method which builds energy forecasts from the bottom-up utilizing load profile data.

The commercial load profile data originates from studies in Connecticut and western Massachusetts over 12 months in 1969.[143] The studies included 13 offices and 10 stores. Commonwealth, in utilizing the NEPOOL data, applies the retail profiles to retail and wholesale categories and office profiles are applied to all other categories. While we hesitate at the small sample size and the application of office load profiles to the remaining employment categories (such as agriculture, fishing, mining, and construction), the Company has aptly pointed out that these categories (which may not be well represented by office profiles) represent a small share of commercial sales. Given the more serious data concerns in the commercial sector, we find these assump-

142 Response to Staff Information Request COMC-7.
143 NEPOOL documentation, op. cit, Tech. Chap. 6, p. 26.

tions to be a reasonable starting point.

D. The Industrial Forecast Methodology

Forecasts of energy demand, disaggregated by SIC, are the foundation of the industrial methodology. Annual consumption for each industry is forecast based on the price of electricity and estimates of kilowatthours consumed per dollar of value added. The electricity price mechanism is taken up in the ensuing "Price Elasticity" section, so this analysis focuses only on the kwh/dollar-value-added method.

Just as the estimates for kilowatthour consumed per employee serve as the key determinant of commercial energy demand, so is the case of kwh per dollar value added in the industrial forecast. The assumption is that a measure of industrial output is a more reliable predictor of industrial demand than employment.

The following is the step-by-step procedure Commonwealth used to develop the industrial forecasts with the NEPOOL model.[144]

(a) Value added is projected for each SIC from a combination of:
   - estimates of "production" vs. "non-production" employees (by industry) and their respective productivity rates (dollar value added per hour worked).
   - estimates of production man-hours
   - estimated dollar value added per man hour worked

(b) Kilowatthours consumed per dollar value added are estimated by industry for the years 1978, 1979 and 1980.

(c) Changes in kwh/dollar value added are projected to change only in response to electricity prices.

144 Forecast, pp. 1.4.62-64.

(d) The product of kwh/dollar-value-added ratios and projected value added yield annual electricity by SIC.

(e) Industrial load profiles (developed by NEPOOL) are used to distribute the annual forecasts over months, and then hours of each day.

The major determinant of industrial demand in the model is value added. The value-added projection method involves numerous assumptions which may or may not be reasonable. For example, it is specified by NEPOOL and again by Commonwealth that "for the purpose of long-range forecast the productivity growth rate of non-production employees will be equal to half that of production employees."[145] NEPOOL supports this assumption by citing the difficulty of estimating these relationships, and offers that .5 "is equivalent to the geometric mean of the New England and U.S. ratios" ... "weighted by 1972 levels of value added."[146]

Another puzzling aspect of the forecast is the comparative growth rates for employment and value added. Commonwealth projects manufacturing employment to grow at 0.2% per year over the forecast period, while value added is projected to grow at a substantially higher rate of 3.4% per year[147] (Energy demand is projected to grow at the slightly slower pace of 3.1% per year.)[148] While this is a plausible result, it is not necessarily an intuitive one. NEPOOL states that "A major feature of the value added estimation process is that the rate of growth of productivity of all (manufacturing) employees is modeled to

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145 Forecast, p. 1.4.64; and NEPOOL documentation, op cit, Chap. 2, p. 5.
146 NEPOOL doc., op cit., Tech. Chap. 2, p. 5.
147 See Forecast, p. 1.4.3 and p. 1.4.113.
148 Forecast, p. 1.4.3.

decline. This is accomplished by incorporating separate exponential productivity growth models for production and non-production employees."[149] Because the rate of growth in productivity is declining does not necessarily mean that value added cannot outpace employment. But the Company's documentation of these interactive effects is not clear.

The Council at this time will not endeavor to review each assumption underlying this method. We support and encourage the Company's efforts directed toward generating service area value added estimates. With most industrial models, value added (or some other measure of output) plays a critical role. Given the importance of these estimates, we urge the Company to investigate the applicability of this method for its service area, and to improve its overall documentation of the methods used. Explicit treatment and justification of the operable assumptions should be included in subsequent forecasts.

The load profiles used to allocate annual consumption by SIC across months and hours originate from a NEPOOL study of 23 industrial customers in Connecticut, 14 in New Hampshire, and 3 in Massachusetts. Again, we are concerned over the relatively small sample size (40 customers) used to allocate energy for 20 different SIC groupings. In several groups, only 1 or 2 customers were sampled. The Company should attempt to verify the applicability of these data for its customers, with particular attention paid to its important industrial classications, such as Non-Electricial Machinery where only 1 customer was sampled.[150]

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149 NEPOOL Doc., op cit., Chap. 2, p. 5.

150 NEPOOL Doc., op cit., Tech. Chap 6, p. 21.

E. Price Forecast and Price Elasticities

1. Price Forecast

Commonwealth projects decreasing prices in real terms for all classes except industrial, which shows a slight increase over the forecast period. A comparison of historical and projected growth rates in real electricity prices is presented below:

Historical and Projected Average Annual
Growth in Commonwealth's Electricity Prices
(Deflated by the CPI)

Class	1960-1970	1970-1980	1982-1991
Residential	- 5.35	1.66	- .29
Commercial	- 4.58	2.60	- .20
Industrial	- 2.60	6.34	.39
Streetlighting	- 2.67	0.50	- .56

The inflation forecast which accompanies the price projections calls for an average rate of inflation of 8.3% over the forecast period.[151] Commonwealth is therefore predicting that electric rates will rise at a slightly slower pace, in the neighborhood of 8% per year when expressed in nominal (including inflation) terms.

2. Price Elasticities

Price elasticities are explicitly incorporated into the residential, commercial, and industrial forecasts.[152] Given the Council's repeated concerns over the lack of elasticity adjustments in past methods, we praise the Company for this inclusion. We do, however, have serious problems with the elasticities used in this initial effort. The elasticities are derived from a NEPOOL review of numerous studies conducted over various time frames and geographic locations (which range

151 See COM/Electric response to Staff Information Request COMP-1.
152 Price elasticities express the percent reduction in consumption given a 1% increase in price, and vice versa when prices decline.

from Los Angeles County to Nebraska to the Tennessee Valley Authority to New England and some are national estimates). NEPOOL has averaged the elasticity values indicated by these studies and applied them to New England. NEPOOL states that "With the exception of the commercial retail trade study, no direct estimates of elasticities were derived by NEPOOL from New England data. Rather, the values.... are based upon certain published elasticity studies where some end-uses or energy classifications are explicitly recognized, engineering knowledge, and practical judgement."[153]

The Company has defended the use of the NEPOOL derived elasticities by compairing "model produced elasticities" with those indicated by the NEPOOL averages.[154] In each case, however, the model-produced class elasticities exhibited a range which did not include the NEPOOL average.[155] Commonwealth offers that "in all cases the Commonwealth Model values fall within the range of elasticities found in the studies."[156] This fact, however, does not support the applicability of the elasticities for its service area, especially given the wide range of elasticities found in the NEPOOL literature review.

The Council recognizes the difficulty in obtaining reliable estimates of price elasticities for each end-use in the model. We do not, however, accept the elasticities now used by the Company without verification. To this end, we attach Demand Condition number 4 requiring the Company to perform an aggregate price elasticity study, by class,

153 NEPOOL Doc., op cit., Tech. Chap. 5, p. 9.
154 See COM/Electric response to Staff Information Request COMPE-1.
155 This result is curious due to the fact that the NEPOOL end-use elasticities were in the model prior to the Comparison, but resulted in a different class mean than that from which they originated.
156 See COM/Electric Response to Staff Information Request COMPE-1.

for its service area. This study should include at a minimum electricity prices, prices of alternative fuels, and income.

F. Peak Demand Methodology

The load profile data in the model combined with service area temperature data is used to project peak demand. Commonwealth forecasts peak demand to grow at the annual rates of 3.1% (summer) and 3.2% (winter) based on average hourly peak day temperatures over the 1970-1981 period.[157]

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157 Forecast, p. 1.4.2.

V. DECISION AND ORDER

On the basis of the foregoing analysis, the Second Long Range Forecast submitted by the Companies is APPROVED conditionally and the Companies are ORDERED to comply with the Demand and Supply Conditions set forth on pages 39 and 65 in this Decision in the Manner and time set forth therein. It is further ORDERED that the Companies submit their First Supplement to the Forecast by November 1, 1983.

Paul T. Gilrain / by CBmcm

Paul T. Gilrain, Esq.
General Counsel

Charles B. McMillan

Charles B. McMillan
Executive Director

On this Decision

James Coyne, Lead Economist
Susan Fallows, Staff Economist

This decision was approved by a unanimous vote of the Energy Facilities Siting Council on February 28, 1983 by those members and representatives present and voting: Chariperson Sharon M. Pollard; Stephen Roop (for Secretary Evelyn F. Murphy); James Brenner (for Secretary Paula W. Gold); David Shutz (for Secretary James S. Hoyte); Richard A. Croteau; Harit Majmudar; and Thomas J. Crowley.

March 2, 1983
Date

Sharon M. Pollard

Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Commonwealth Gas Company (EFSC 82-5) and Hopkinton LNG Corporation (EFSC 82-6) for Approval of their Second Long-Range Forecasts of Gas Resources and Requirements, 1982-1987	EFSC 82-5 EFSC 82-6

FINAL DECISION

Hearing Officer
Lawrence W. Plitch, Esq.

On the Decision:

Juanita M. Haydel, Lead Analyst
Susan Fallows, Staff Economist

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LIST OF FIGURE AND TABLES

TENTATIVE DECISION

The Energy Facilities Siting Council hereby APPROVES the Second Long-Range Forecasts of Gas Resources and Requirements of the Commonwealth Gas Company (hereinafter "Commonwealth" or "the Company") and Hopkinton LNG Corporation (hereinafter "Hopkinton") subject to the CONDITIONS developed herein and outlined at the conclusion. The background of the Companies, the history of the proceedings, and previous Conditions are discussed in Section I. Section II outlines the standard of review and the technical description and analysis of the Company's Second Long-Range Forecast. Section III is a description and discussion of Commonwealth's Conservation Programs. Section IV is a description of the Company's supply contracts and facilities. Section V compares the Company's resources and requirements for a normal year, a design year and a peak day and discusses the Company's ability to meet its customers' requirements in a "cold snap". Section VI approves the filing of the Hopkinton LNG Corporation. Finally, Section VII outlines the Conditions pertaining to the next forecast by the Commonwealth Gas Company.

I. INTRODUCTION

A. Background

The Commonwealth Gas Company, the second largest gas distribution company in the State, is franchised to distribute and sell natural gas to residential, commercial and industrial customers in 51 communities in eastern, southeastern and central Massachusetts. For operational purposes, the Company is separated into two zones. Zone 1, the larger of the two zones, is separated into two, non-continguous divisions. The larger of the divisions is in central Massachusetts and includes Worcester, Framingham, Dedham and part of the City of Boston. The other division of Zone 1 is composed of the City of Cambridge and part of Somerville. Zone 2 is in southeastern Massachusetts and includes New Bedford, Plymouth, and Fairhaven. The Company's service territory is shown in Figure 1.

In the 1981/82 split-year the Company provided firm service to 199,000 customers, 92 percent of which were residential. Total firm sales in 1981/82 totalled 34,917 MMcf of which, 56 percent were sold to residential customers; 24 percent were sold to commercial customers; and 16 percent were sold to industrial customers. Total firm sendout in the 1981/82 split-year is shown in Table 1. In addition to sales to firm customers, the Company also has historically sold a small amount of gas to several customers on an interruptible basis.

The Company is a wholly-owned subsidiary of Commonwealth Energy System (formerly New England Gas and Electrical Association). The Company, as it is presently organized, is the result of several mergers of smaller gas companies that have occurred over a period of years. The most recent acquisition occurred on January 1, 1981, at which time the Company acquired the gas assets of New Bedford Gas and Edison Light Company, also a wholly-owned subsidiary of Commonwealth Energy System.

The Commonwealth Energy System ("the System") is a Massachusetts trust whose principal operating subsidiaries include the Commonwealth Gas Company the Commonwealth Electric Company and the Cambridge Electric Light Company. In addition to these divisions, the System owns a 34.5 percent interest in Algonquin Energy, Inc., which in turn owns all of the common stock of Algonquin Gas Transmission Company, a major supplier of gas to the Commonwealth Gas Company. The System also owns 50 percent of the outstanding common stock of Hopkinton LNG Corporation, which is engaged in the operation of LNG facilities located in Hopkinton and Acushnet, Massachusetts. Commonwealth has entered into a 25-year contract with Hopkinton for LNG liquefaction, storage and revaporization

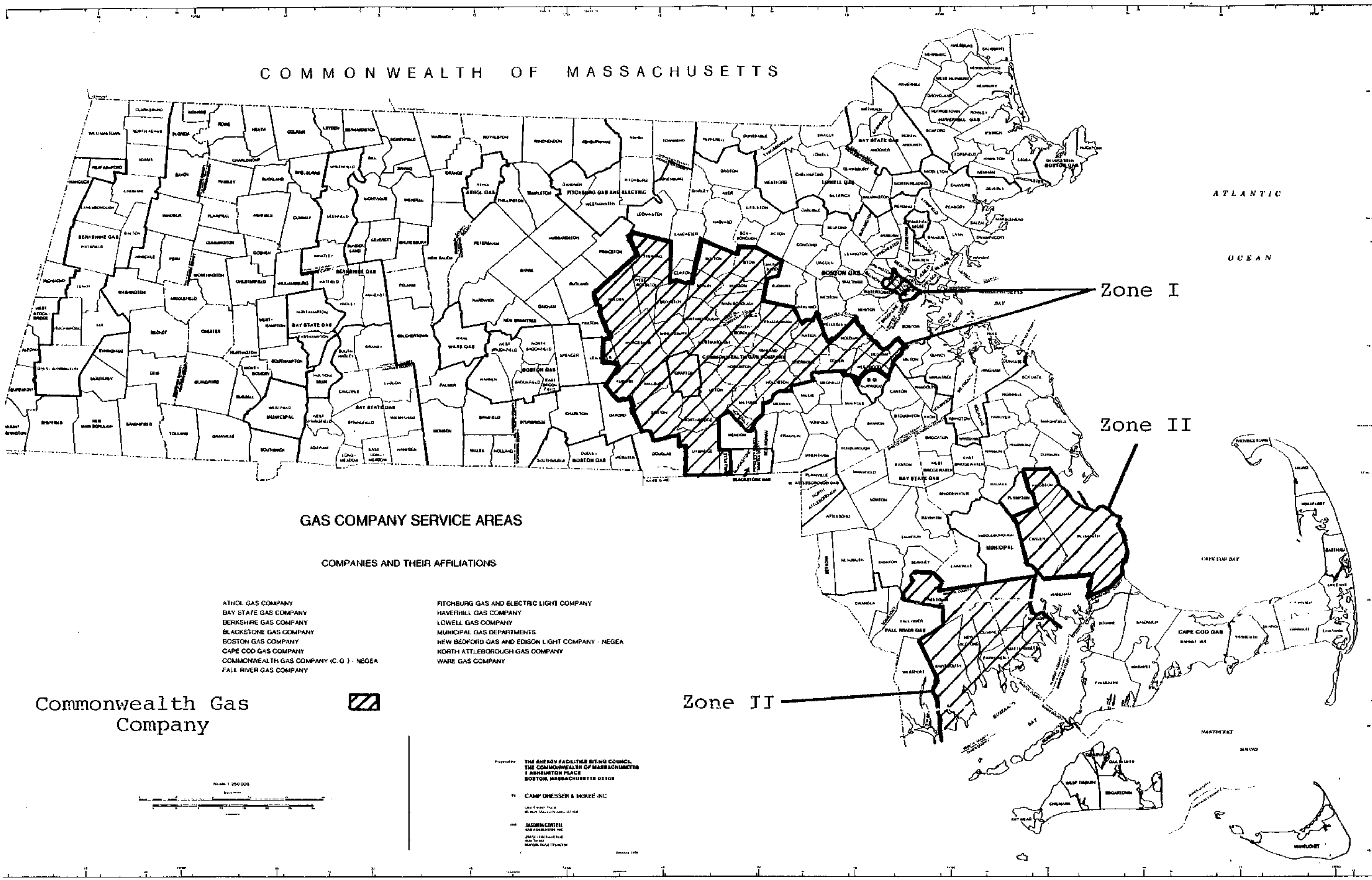
COMMONWEALTH OF MASSACHUSETTS
ATLANTIC
OCEAN
Zone I
Zone II
Zone II
GAS COMPANY SERVICE AREAS
COMPANIES AND THEIR AFFILIATIONS
ATHOL GAS COMPANY
BAY STATE GAS COMPANY
BERKSHIRE GAS COMPANY
BLACKSTONE GAS COMPANY
BOSTON GAS COMPANY
CAPE COD GAS COMPANY
COMMONWEALTH GAS COMPANY (C. G.) - NEGEA
FALL RIVER GAS COMPANY
FITCHBURG GAS AND ELECTRIC LIGHT COMPANY
HAVERHILL GAS COMPANY
LOWELL GAS COMPANY
MUNICIPAL GAS DEPARTMENTS
NEW BEDFORD GAS AND EDISON LIGHT COMPANY - NEGEA
NORTH ATTLEBOROUGH GAS COMPANY
WARE GAS COMPANY
Commonwealth Gas Company
CAMP DRESSER & McKEE INC.

TABLE 1

Commonwealth Gas Company
Firm Sendout (MMcf)

	1981/82	
	Non-Heating Season	Heating Season
Residential		
with heating	5,268	13,506
without heating	486	421
Commercial, firm	2,765	5,764
Industrial, firm	2,671	2,973
TOTAL FIRM	11,214	23,703

SOURCE: Forecast, Tables G1-G3.

services. Natural gas obtained by the Company under its firm contracts is liquefied by Hopkinton, principally during the April 1 to November 1 liquefaction season.

B. History of the Proceeding

The Commonwealth Gas Company and Hopkinton LNG Corporation filed timely their Second Long-Range Forecasts on September 1, 1982. No new facilities, as defined in Ch. 164, sec. 69G, were proposed for adjudication. Notice of intent to conduct a single combined adjudicatory proceeding on the two forecasts was issued by the Hearings Officer on September 14, 1982. The Company gave proper notice of the proceeding by publication in local newspapers and posting in city and town halls. No requests to intervene were received.

A set of Document and Information Requests was issued to the Company on October 12, 1982. The Company was directed to respond to the Document Requests on November 4, 1982. Responses to the Information Requests were due on November 23, 1982. A technical session was held on November 4, 1982. A second set of Information Requests was sent to the Company on December 15, 1982. The Company responded to these questions on December 30, 1982. A second technical session was held on January 10, 1983.

C. Previous Conditions

The Council's Decision in review of the Company's Fourth Annual Supplement imposed four Conditions, as follows:

1. That the Company begin to compile with the next forecast and in subsequent years a record of normalization factors which it calculates in the course of producing its forecast;

2. That the Company provide to the Council within ninety (90)

days a response to the Council's evaluation of its sendout forecast methodology, and be prepared to hold a technical session with Council staff concerning this response. Such response should discuss the reliability of base use, normal year, design year, and peak day normalization factors; the forecast of additions to load; and the forecast of customers conservation. The Company response should discuss what portions of the Council analysis it believes to be valid or invalid, and discuss Company plans to conduct research or otherwise improve those aspects of the methodology which the Company agrees need to be improved;

3. That the Company provide with its Second Forecast an evaluation of a demand management strategy that includes conservation grants and installation service. The evaluation should discuss the cost-effectiveness of such strategy to the Company and its ratepayers;

4. That the Company file its Second Forecast on July 1, 1982. Such filing should combine data from the former Commonwealth and New Bedford Systems.

The Company has complied with Conditions 1 and 3 in its current filing. With regard to Condition 2, it was agreed upon by the Council staff and Company representatives that no technical session was necessary and that all concerns would be addressed in the Second Long-Range Forecast. These three Conditions are discussed, infra. On June 4, 1982 the Company requested and was granted an extension of its filing date from July 1, 1982, to September 1, 1982.

II. FORECAST OF SENDOUT REQUIREMENTS

A. Standard of Review

In its review of forecasts and supplements thereto, the Council requires each gas company to project "the gas requirements of its market area" over a five year period and to describe "actions planned to be taken by the company which will affect capacity to meet such requirements..." G.L. c. 164, sec. 69I. Under EFSC Rule 62.9(2), forecasts of sendout must be based upon historically accurate information and reasonable statistical projection methods. In its Decisions of recent years, the Council has found statistical projection methods to be "reasonable" if they are reviewable, reliable and appropriate. A methodology is reviewable if it is clearly and thoroughly described or documented, so that its results may be duplicated by another person given the same information. It is reliable when it provides a measure of confidence that the assumptions, judgement and data which comprise it will forecast what is most likely to occur. A methodology is appropriate when it is technically suitable for the size and nature of the particular system.

The Council's Decisions in review of the Third Annual Supplements of Commonwealth[1] and New Bedford Gas Companies[2] focused upon the reviewability of the forecasts. The Council found that the Companies had not fully documented their forecast methodology. It was found that the Company had not explained:

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1 See 4 DOMSC, p. 99, EFSC 79-5, Commonwealth Gas Co., August 11, 1980.

2 See 4 DOMSC, p. 176, EFSC 79-7, New Bedford Gas and Edison Light, August 11, 1980.

- how forecast sendout was divided between heating and non-heating seasons (4 DOMSC, EFSC 79-5 at 103)
- what heating increments were used to forecast design year sendout, or how these increments were estimated (pg. 104)
- what factors were used to forecast peak day sendout, and how they were estimated (pg. 104)
- how the Company determined its estimates of conservation and additional sales (pg. 105); nor
- how the Company estimated heating increment and base use (p. 106).

The Council found that the forecast was not reviewable absent this documentation. The Council attached several conditions to the forecasts' approval.[3] The Companies were required to explain the bases of significant judgements (Condition 1, EFSC 79-5); explain how additional sales were forecast (Condition 2); and state the factors used in estimating base use and heating increment, and these factors' bases (Condition 4).

The Council's review of the Companies' Fourth Annual Supplement[4] found that through compliance with the above Conditions the forecasts met the Council's criterion of <u>reviewability</u>. The review of the Fourth Annual Supplement focused on the <u>appropriateness</u> and <u>reliability</u> of the Company's forecast. In sum, the Council found in EFSC 80-5 that the Company's estimates of the six key variables used in forecasting sendout were less reliable than the Company was capable of producing. It was

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3 The same Conditions were attached to both EFSC 79-5 and 79-7.

4 The review of Commonwealth Gas Company's and New Bedford Gas and Edison Light's Fourth Annual Supplements were merged into one adjudication docketed as EFSC 80-5.

noted that the reliability of the forecast could be improved through the development of Company specific data on customer usage patterns, on conservation activities, on the variability of sendout per degree day, and other behavioral issues.

This review of the Company's Second Long-Range Forecast will focus on further improving the reviewability and reliability of the Company's forecast methodology and supply planning.

B. Description of Methodology

This section describes and analyzes the Company's methodology for forecasting sendout requirements. First, an overview of the methodology is presented, followed by a more detailed description and a critique of the key steps and variables in the Company's methodology. For clarification Figure 2 provides a flowchart of the Company's forecasting process.

1. Overview

The Company begins its forecasting process by normalizing the most recent monthly historical split-year sendout data available. This is first done by determining monthly aggregate sendout, defined as total monthly sendout less interruptible and large industrial loads. Monthly base use, varying with temperature, is estimated, and subtracted from aggregate monthly sendout to derive monthly heating use. Heating use factors (heating use per degree day) are estimated using two methods and used to adjust 1981/82 actual heating sendout to reflect expected usage during normal weather conditions. The actual heating use is adjusted a second time using the same heating factors to reflect expected usage during design weather conditions. Monthly base use and heating use are

Figure 2

Commonwealth Gas Company

Forecast of Normal Year and Design Year Requirements

Actual 1981/82 "aggregate" sendout →

Separate 1981/82 aggregate sendout into base load and heating load by month using Zinder factors →

Develop monthly heating factors (heating use per degree day) using two different methods →

Using heating factors, adjust 1981/82 actual data, once to reflect usage in a normal year, and again, to reflect expected usage in a design year. →

→ Add new load estimated by Marketing Dept., by month, by customer class to normalized 1981/82 data and to 1981/82 data adjusted to reflect usage in a design year →

Adjust this data to reflect the expected effects of conservation, estimated at 1% of existing use in each month, in each class and in a normal and design year →

Add large industrial use forecast to forecast of normal and design aggregate requirements →

OUTPUT

1 Forecast of Normal Year Firm Requirements in 1982/83

2 Forecast of Design Year firm Requirements in 1982/83

3. 1982/83 Design Firm Requirements ÷ by 1982/83 Normal Firm Requirements = "Scaling Factors"

Apply scaling factors to forecast of normal year requirements (1983/84 - 1986/87)

Design year firm requirements for 1983/84 - 1986/87 then allocated to customer classes. Base use is allocated to customer classes based on estimated July and August usage for each class. Heating use is allocated to each customer class based on the proportion of heating use by each customer class for a twelve month period. The Marketing Department estimates future load additions by month and customer class for two years into the forecast period. These are then added to the normalized data to arrive at expected normal sendout in 1982/83 the first forecast year. It is at this point that conservation adjustments are factored in and expected large industrial load and Company Use and Unaccounted For gas is added to arrive at forecasted total firm sendout in the 1982/83 normal year.

To forecast design requirements, similar steps are involved. Expected load additions are added to the previously adjusted actual sendout data, adjustments are made to reflect the effects of conservation, and expected large industrial load and Company Use and Unaccounted For quantities are added to arrive at forecasted total firm sendout for a 1982/83 design year.

Scaling factors are derived for each month based on the ratio of forecasted design sendout and forecasted normal sendout in the 1982/83 split-year. For the forecast years 1983/84 through 1986/87, these same scaling factors are applied to monthly forecasts of aggregate normal sendout to derive forecast design sendout.

Peak day sendout is determined based on the normalized base and heating load for the previous January. Adjustments are made to account for the variability of the previous year's sendout to degree day relationships and anticipated variability in the upcoming season from such things as changing economic conditions.

Each step of the Company's methodology is examined in detail in the following sections.

2. Base Use and Heating Use Allocation

The Company defines aggregate sendout as total firm sendout less large industrial load and calculates this by subtracting interruptible and large industrial sales from total sendout. The Company removes large industrial load from firm sendout to eliminate fluctuations in aggregate sendout which might result from fluctuations in its large industrial sales. The fact that there are relatively few large industrial customers accounting for a large volume of sales allows the Company to do this and seems like a reasonable approach to the Council. Expected load in this class is forecasted in a separate process and added back into forecasted aggregate sendout.[5]

The next step in the Company's forecast is to determine monthly base use. Actual aggregate sendout for July and August, typical non-heating months, is averaged to determine base use in those months. Monthly base use factors are applied to the average of July and August sendout, with adjustments made for the number of days in the month, to arrive at monthly base use. The base use factors range from 1.00 for July and August, reflecting base use in non-heating months, to 1.50 for January and February, reflecting increased use of gas by appliances during the coldest months. The average daily aggregate sendout for July and August (31 MMcf per day), times the monthly factor, times the number of days per month gives the monthly base for aggregate sendout. The

5 Response to Question SF-2, Information Requests Set 2, EFSC 82-5, November 23, 1982.

monthly base use factors and a sample calculation are shown in Table 2.

The monthly base use factors are based on a 1957 report by H. Zinder Associates, Inc.[6] The factors are based on billing data for four Midwest and Middle Atlantic gas companies for residential cooking and water heating use. In the Decision on the Company's Fourth Annual Supplement, the Council expressed concern over the use of the Zinder factors.[7] The Council stated that the Company had not shown that these factors, developed twenty-five years ago and based on systems in other parts of the Country, were applicable to the customers of the Commonwealth Gas system.

The Company is unique in its efforts to correlate base use to temperature. Most gas companies, in their forecasts, assume that base use is flat throughout the year, and incorporate the increased use of gas by appliances during the winter months into their estimates of heating use per degree day. The Council lauds the Company's efforts to refine this approach. However, there are three problems with the use of this data in the Company's forecast.

First, the Company assumes that this data, developed twenty-five years ago, is applicable to its system today. Certainly, gas consumption patterns have changed over the past quarter century, as have appliance efficiencies, the thermal integrity of homes, and customer behavior patterns. As other Massachusetts companies have shown in their forecasts, gas consumption patterns have changed in recent years in response to such things as increased prices and greater awareness of energy costs and conservation, as well as changes in homes construction.

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6 Criteria for Determining Costs of Gas and Electric Service in Military and Public Housing Projects; Clifford A. Brandt, H. Zinder & Associates, Inc., December, 1957 (hereinafter "Zinder").

7 See 7 DOMSC, p. 169, EFSC 80-5, Commonwealth Gas Company; December 30, 1981.

TABLE 2

Commonwealth Gas Company

Monthly Base Factors and Base/Loads
(1981/82)

	Non-Heating Season			Heating Season	
	Factor	MMcf		Factor	MMcf
April	1.39	1,292	November	1.29	1,199
May	1.20	1,153	December	1.45	1,393
June	1.08	999	January	1.50	1,441
July	1.00	961	February	1.50	1,302
August	1.00	961	March	1.48	1,422
September	1.03	958			
October	1.17	1,124			
		7,448			6,757

SAMPLE CALCULATION:

July & August - Average daily aggregate sendout:
961 MMcf ÷ 31 days/month = 31 MMcf/day

January - monthly base use:
(31 MMcf/day)(31 days/month)(1.50) = 1,441 MMcf

SOURCE: Forecast, Section I, pg. 2.

The changes in gas usage patterns and customer behavior unquestionably have been more dramatic in twenty-five years.

Secondly, the Company assumes that these factors, developed on billing data from Midwest and Mid-Atlantic gas companies, are applicable to the Company's service territory. Just as usage patterns vary across one company's service territory depending on variations in climate, income, housing stock and energy prices, usage varies across regions of the country. As is noted in the Zinder report, "annual gas and electric consumption... will vary with location. The percentage of heating and cooling consumption units by month will also vary with location."[8] This variation may or may not be greater now than twenty-five years ago. The Company has not made the case either way.

The final concern with the use of the Zinder factors is the applicability of these residential cooking and water heating use factors to all customer classes of the Commonwealth gas system. The Company applies the Zinder factors to total aggregate sendout to derive system-wide base use. The Company has not demonstrated that base use over all customer classes exhibits the same patterns as residential non-heating customers of its own system, much less of a system in another region of the country, twenty-five years ago. Certainly, the distribution of base use of a commercial or industrial customer over a year may differ greatly from that of a residential non-heating customer. In fact, base use patterns of a residential heating customer may differ greatly from that of a residential non-heating customer.

The reliability of the Company's forecast methodology is the ultimate concern here. As will be shown later in this Decision and

8 Zinder, at p. 14.

Order, the reliability of the other key variables in the Company's methodology, such as heating use, heating use per degree day factors, normal, design and peak day forecasts of requirements, depends directly on the reliability of the estimate of the base use factors, and in turn, base use. Therefore, it is imperative that the Company develop reliable estimates of base use for its system.

The Council recognizes that what may be reliable and appropriate for one gas system may not be so for another. To require that a small gas system undertake the same improvements to their methodology as a large system would be burdensome. It is imperative that Commonwealth Gas, the second largest gas company in the state, develop a methodology that is reliable and technically appropriate for the size and nature of its system. Although the Council's concerns may seem to vary from year to year and from company to company, they are directly related to the progress a company has made to date. Forecasting accurately and reliably is an ongoing, incremental process and it is implicit in the Council's mandate to improve a company's forecasting capability through Decisions and Orders that recognize this incremental approach. To this end, the Company is directed to develop company specific base use factors, using the most reliable estimate available. If this is not possible before the next filing, the Company should present a satisfactory plan for developing this data. The Council staff welcomes the opportunity to assist the Company in this matter. Condition number 1 addresses this concern.

Base load is allocated to customer classes based on the average of August and September 1981 billing data, which, due to lagged billings, relates to July and August sendout. Table 3 shows the allocation of base use by customer classification.

The Company then calculates aggregate monthly heat sensitive use by subtracting monthly base use from total monthly aggregate sendout. Heat sensitive load is allocated to each customer class according to its percentage of the sum of the heating load for the twelve month period ending in March, 1982. The percentages shown in Table 4 are applied to the monthly heat sensitive loads. The monthly base loads and heating loads are summed for each customer class to arrive at total use in each customer class.

2. Normalization Factors

a. Heating Use Factors

Normalization factors for each month of the heating season are derived from actual data for the corresponding month in the 1981/82 heating season. A least squares regression is run on firm sendout and degree day data for selected periods in each of these months. The periods are chosen based on how representative the data are for the month. The primary factor determining this is the extent to which the Company is able to separate the effects of interruptible sendouts. The Company will generally choose periods when there were no interruptible sales or when interruptible sales were at a minimum. In addition, the Company attempts to choose a 14-day consecutive period which does not include a major holiday.[9]

The Company then determines average daily sendout and the average daily degree day level for each period. These average figures lie on

9 Response to Question 3, Information Requests Set 2, EFSC 82-5, December 30, 1982.

TABLE 3

Commonwealth Gas Company

Base Load Allocation Factors*

	% of Total
Residential with Heating	45.9
Residential without Heating	6.1
Firm Commercial	27.8
Firm Small Commercial	20.2
	100.0

* Based on August and September 1981 billing data

SOURCE: Forecast, Section I, pg. 2.

TABLE 4

Commonwealth Gas Company

Derivation of Heating Use Factors

	Total Sales 12 Months Ending March, 1982	Annual Base	Annual Heat	% of Heat
Residential with Heating	18,183	5,870	12,313	69
Commercial	8,193	3,555	4,638	26
Small Industrial	3,475	2,577	898	5
				100

SOURCE: Forecast, Section I, pg. 3.

the regression line in each month.

To determine the average daily heat sensitive load for the month, the average daily base and the average daily large industrial are subtracted from the average daily firm load. As discussed, supra at page 14, the average daily base is equal to the average of July and August sendout, divided by 31 (the number of days in both July and August), times the monthly base use factor. The average daily large industrial load is equal to the total monthly large industrial load divided by the number of working days in the month.

The average daily heat sensitive load divided by the average daily "cutback" degree day level gives a monthly heating factor in MMcf per degree day. The Company uses a "cutback" degree day figure calculated on a 59 degree day base rather than a 65 degree day base, as is usual. For example, a temperature of 5 degrees Fahrenheit using a 65 degree day base would contain 60 degree days (65-5). This same temperature using a 59 degree base would contain 54 degree days (59-5), 6 degree days less than with a 65 degree day base.

For January 1981 the average daily firm sendout was 239.9 MMcf. The monthly base was 46.5 MMcf. The average daily large industrial load was 7.95 MMcf. The heat sensitive load (185.4 MMcf) divided by the average daily cutback degree day level (47.1) gives a heating factor of 3.9 MMcf per degree day. Table 5 shows complete calculations for January.

To verify the heating factor calculated above, and to derive normalization factors for the fringe months, an alternative method is used. The monthly heat sensitive aggregate load is divided by the cutback degree day level. For January, the monthly base was 1441 MMcf (average of July and August sendout aggregate times 1.5). The heat sensitive aggregate sendout was 4804.3 MMcf. The actual number of degree days (59 degree base) was 1,236. The heat sensitive load divided by the cut-back degree day is equal to 3.89 MMcf per degree day.

The heating factors produced for fringe months using this alternative method are adjusted where necessary. Adjustments are based on judgement and are necessary so that heating factors follow the expected pattern of increased use per degree day during the winter months and decreased use per degree day in the summer months.

The normalization factors for 1981/82 using the two methods and actual factors used are shown in Table 6.

There are several concerns with the development of the heating factors. These are the use of the regression technique, the choice of periods and the use of the cutback 59 degree day base. These are examined in turn below.

In the normalization process, the Company runs a least squares regression on sendout and degree day data for each month in the heating season. However, in actually deriving the heating factors used, the Company uses only average daily sendout data, information not obtained from the regression results. It is assumed then that the Company uses the regression results, particularly the slope of the regression line (which would relate to sendout per degree day) as a check on the heating factor calculated from the average daily figures. How the regression results are used and what information, if any, is obtained from this

TABLE 5

Commonwealth Gas Company

Derivation of Normalization Factor - January

AVERAGE DAILY
BASE USE

July and August average use	(948 + 973) - 2 = 960.5 MMcf
July and August average daily use	960.5 ÷ 31 = 30.98
July and August average daily base times the January base use factor	30.98 X 1.5 = 46.5 MMcf

AVERAGE DAILY
LARGE INDUSTRIAL USE

total monthly large industrial divided by the number of working days in January (20).	159 MMcf ÷ 20 = 7.95 MMcf

AVERAGE DAILY
HEATING USE

Average daily firm sendout	239.9 MMcf
minus average daily base use	- 46.5
minus large industrial use	- 7.95
Average daily heat sensitive use	185.4 MMcf
divided by 47.1 degree days (59° base)	3.9 MMcf/degree day

TABLE 6

Commonwealth Gas Company

Monthly Normalization Factors
(MMcf/Degree Day)

	1981/82		
	Calculated First Method	Alternate Method	Used to Normalize
September		2.98	3.0
October		3.57	3.5
November	3.63	3.51	3.6
December	3.73	3.51	3.8
January	3.94	3.89	3.9
February	3.75	3.89	3.8
March	3.71	3.98	3.7
April		3.84	3.7
May		3.06	3.1
June		-	-
July		-	-
August		-	-

SOURCE: Forecast, Section I, pg. 4.
Response to Question SF-9, Information Requests Set 1, EFSC 82-5, November 23, 1982.

analysis, is not explained by the Company. The Company is directed to more thoroughly document this step of the normalization process in future filings. Condition 2 addresses this issue.

The Company states that it chooses periods of minimum or no interruptible sales. These periods would generally correspond to days of very cold weather, a time when the company is least likely to sell gas to interruptible customers. This would in turn have the effect of producing a conservative (high) heating factor, assuming that heating use per degree day increases as the temperature increases, a generally agreed upon phenomenon. The Company is cautioned to be aware of the sensitivity of its forecast of requirements to this conservative approach.

In calculating the average daily heating use, the Company subtracts the average daily base and the average daily large industrial load from the average daily firm sendout. The average daily large industrial load is calculated by dividing total large industrial load for the period by the number of <u>working days</u> in the period, rather than the total number of days in the period. The result is the overestimating of average daily large industrial load for the period and the underestimating of average daily heat sensitive load. This in turn has the effect of underestimating the heating factor. As noted above, the Company should examine the sensitivity of its forecast to these biases.

The Company states that the 59 degree day base for heating degree days was derived from empirical observation and judgement. Analysis by the Company of its own data revealed that sendouts for days with only a few degree days did not vary significantly from sendout on days with no degree days.[10]

The Company states that the original assumption behind the 65 degree day base for degree days was as follows: assuming a 70 degree thermostat setting and a 5 degree heat gain from appliances and household activities, heat would not be required until the outside temperature reached 65 degrees. The Company, as well as the American Gas Association, argues that since the 65 degree base was developed many people have improved the thermal integrity of their buildings, therefore, reducing heat loss. In addition, many people have set back their thermostats to save energy. It is argued that insofar as the inside temperature and heat loss have been reduced, heat would not be required until the outside temperature cooled to a temperature lower than 65 degrees.[11]

The Company states that its empirical observations indicate that sendout on days with only a few degree days does not significantly differ from sendout on days with no degree days. The Company offers this fact as support for the argument that a 59 degree day base is more appropriate than the 65 degree day base used by most gas companies in planning sendout requirements.

Every other Massachusetts gas company uses a 65 degree day base in its filing to the Council. Although we appreciate the Company's efforts

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10 Response to Question 2, Information Requests Set 2, EFSC 82-5, December 30, 1982.

11 Id.

to introduce new forecasting techniques, it is up to Commonwealth Gas to demonstrate to the Council that the use of a 59 degree day base is more appropriate and reliable.

As the outside temperature falls and the difference between inside and outside temperatures increase, the heat loss from the home increases. On peak days many home heating systems reach their maximum capacities, and must run constantly to counter the effects of increased heat loss. Certainly, on these days, usage per degree day patterns differ significantly from those the Company has examined in support of the use of a 59 degree day base. The Council is concerned that the use of the 59 degree day base result in less accurate forecasts of sendout requirements on a peak day and over the heating season, both normal and design. The Company is directed to provide additional support and explanation of its use of a 59 degree day base in its next filing. The Company should demonstrate that the 59 degree day base is more appropriate and reliable than the 65 degree day base. Condition 3 addresses this issue.

Finally, the Council is concerned that the use of a single set of heating factors to forecast the requirements of all firm customers may lead to considerable inaccuracies. The Council lauds the Company's progress in producing a separate heating factor for each month of the heating season, but as noted earlier in this Decision, forecasting is an ongoing, incremental process, and in a time when the ability to forecast accurately is becoming increasingly important it is imperative that a company of Commonwealth's size have a thorough understanding of customer usage patterns, at least at the level of customer classes. The Company is therefore directed to examine the data available to it in deriving the heating increments by customer class. The next filing to the Council should reflect both efforts to date and future plans for incorporating this data into the forecast. Condition 4 addresses this concern.

b. Normal Year Adjustment

As do all Massachusetts gas companies, Commonwealth prepares a forecast of requirements under two sets of weather conditions: normal, a year which is neither colder nor warmer than normal, and design, the coldest year for which a company plans to meet sendout requirements. The degree day data is derived form the Company's temperature recording equipment in Worcester. The Company has checked the correlations between the sendouts in the other divisions with the Worcester degree days and found them to be as high as correlations with degree days measured in the particular division.[12]

As discussed, supra, at 23, in preparing the forecast the Company uses a 6 degree cutback from the 65 degree day base. However, in reporting historical degree day data a 65 degree day base is used. In addition, it is assumed that July and August degree days do not contribute to heat sensitive loads and therefore, are not significant.[13]

The Company uses a normal year of 6,485 degree days. This is based on the average of the actual degree days experienced from 1952 to 1977. On a 59 degree day base this figure is lowered to 4817 degree days.

12 Response to Question SF-17, Information Requests Set 1, November 23, 1982.

13 Response to Question 1, Information Requests Set 2, December 30, 1982.

The normalization factor is multiplied by the variation between the normal degree day level for the month and the actual level on a 59 degree day base. If the actual month's weather is colder than what would be expected in a normal year, the Mcf adjustment factor is negative and the actual aggregate sendout is reduced in that month. If the month is warmer than normal, the Mcf adjustment factor is positive and the normalized aggregate sendout is greater than the actual aggregate sendout. The normalized aggregate sendout is allocated to customer classes in the same manner as actual aggregate sendouts, as discussed, supra, at 20.

c. Design Year Adjustment

The Company uses a design year criteria of 7,304 degree days on a 65 degree day base, reflecting the coldest year experienced (1955-56). The distribution of degree days is based on the actual distribution in that year. For calculating design year and peak day requirements, the Company uses the equivalent of this on a 59 degree day base (5682 degree days). In addition, the degree days in July and August are excluded, as not contributing to the heat sensitive loads.

The same factors developed to normalize 1981/82 actual data are used to estimate the expected usage in 1981/82, had design weather conditions existed. The heating factor is multiplied by the cut-back degree-day variation between actual and design weather conditions to determine an Mcf adjustment. If the actual month was colder than design weather conditions, the Mcf adjustment is negative and the aggregate sendout is reduced. If the actual month is warmer than normal, the Mcf adjustment factor is positive and the aggregate sendout is increased.

3. Future Sales

a. Marketing Department Forecast

The Company's Marketing Department provides estimates of future sales by customer class and contract years for two years into the forecast period. The Marketing Department's forecasting process begins when the Gas Supply Department determines the amount of gas that can be committed to new load. This is done by first determining the amount of gas available to sell during a normal year, allowing sufficient resources for design weather conditions. Actual sendout in the last year is subtracted from this to arrive at the volume of gas available for sale. Added to this is the gas "supply" available due to the effects of conservation, calculated at 1 percent of actual firm sendout. These two volumes of gas are added to arrive at total supply available for sale.

This volume is then matched against current trends and expected short-term future market conditions to determine the period of time that will be required to add this new load. The current forecast calls for the addition of 2,500 MMcf over the two year period 1982/83 to 1983/84.

Each year the Marketing Department conducts forecast interviews with key industrial accounts to determine expected production levels and resultant gas consumptions. Based on these interviews, it was determined that 400 MMcf of available supply should be set aside as the volume that would come back on line once economic conditions and production levels increased.

To date, the Company has been unable to separate the effects of conservation on sendout from those due to poor economic conditions. To provide a contingency, a volume of 500 MMcf was set aside.

Table 7 summarizes the Company's projection of supply available to sell over the next two years.

The Company notes that an important underlying assumption is that the price of gas will be competitive with Number 2 heating oil, allowing the Company to secure the new load additions it is seeking.[14] The Company states that it feels the potential customer will opt for natural gas provided that the Company's price does not exceed 110 percent of the price of oil.[15] The Company argues that for gas prices to exceed oil by 10 percent, oil prices would have to remain unchanged while gas prices would have to increase by over 40 percent. The Company sees the combination of these events as unlikely.[16] While the Company recognizes the possibility of a gas price spike as a result of deregulation, it feels that this would be shortlived and would not result in a loss of load.[17] "From a practical standpoint," the Company states, "gas will have to be priced to compete with No. 2 oil if the producers expect to sell their product."[18]

While the Council does not doubt that the Company plans prudently, there is concern over the ability of the Company to market the gas it plans to sell in the future. Given recent occurrences in the world oil markets, it is conceivable that the price of natural gas could exceed that of oil by 10 percent in the near future. While recent phenomena

14 Forecast, Section 1, p. 1.

15 Response to Question P-3, Information Requests Set 1, November 23, 1982.

16 Id.

17 See Response to Question P-4, Information Requests Set 1, November 23, 1982.

18 Id.

Table 7

Commonwealth Gas Company

Basis for Establishing Load Addition Target

	Firm Sales (MMcf)
Objective Sendout	37,300
1981 Sendout - Actual	34,600
Available for Sale	2,700
Plus projected conservation of 1%/year for 2 years	700
	3,400
Less probable set aside due to poor economic conditions	400
	3,400
Less Contingency	-500
TARGET	2,500

Source: 1982/83 Load Forecast, Response to Document Request D-1(j), Information Requests Set 1, November 4, 1982.

might be short lived, it could significantly affect the Company's marketing plans in the future, particularly residential oil to gas conversions and the ability to add and retain commercial and industrial customers, particularly those with dual-fuel capability. An "oversupply" of gas could have the effect of increasing costs unnecessarily.

It is imperative that the Company continue to monitor and assess the impacts of natural gas price decontrol on its ability to secure new load. Implicit in this is the need to monitor the price and availability of alternative fuels, particularly number 6 and number 2 fuel oil, and how this effects the competitiveness of natural gas. The Council expects these issues to be thoroughly addressed and documented in its next filing. Condition 5 addresses these issues.

When the 1982-83 forecast was prepared, residential oil to gas conversions in the Company's service territory were at relatively low levels as compared to those of 1979-81. The forecast assumes that residential conversions will continue at current levels. The Company notes both the doubt in the marketplace caused by speculation regarding rapid acceleration of gas costs and the media attention to actual substantial increases in gas costs as causes of this decline in conversions.

New home projections for 1982 were based on recent levels. For the 1983 forecast, it was also assumed that mortgage rates would ease to allow the additions of new homes to return to 1980-81 levels of activity, i.e., 14 percent higher than 1982.

Planning of load additions in the commercial and industrial markets often involves long-range tentative commitments to proposed new construction and production process modifications. Eighty percent of the 1982 commercial/industrial forecast was based on previously accepted new loads and 20 percent on historical trends. For 1983, the Company bases its forecast on 50% actual accepted loads and 50% on historical data. The historical data included the amount of new construction activity that had occurred in recent years and was expected to continue into the future.

The Company includes in the commercial/industrial forecast 236 MMcf in oil to gas conversions of less desirable temperature affected loads. The Company states that it was necessary to add this previously restricted load to bring the forecast up to the two year target protection of 2,500 MMcf. A base load factor of 40 percent in 1982 and 30 percent in 1983 is used to spread these forecasted commercial/industrial load additions. The Company uses these types of load additions to balance the effect of deviations in the residential portion of the forecast, e.g., if greater than anticipated residential conversions occur, less commercial/industrial temperature affected load will be accepted.

Projections of load additions by customer class for the first two calendar years of the forecast period are shown in Table 8. These figures include actual load additions through June, 1982. Of the 2,500 MMcf expected to be added through December of 1983, 25 percent is expected to be residential, 47 percent commercial, and 28 percent industrial. Of the added residential load, 38 percent is expected to be due to new home construction and 62 percent is expected to be due to oil to gas heat conversions of existing gas customers.

The Company conducts periodic samplings of actual additions performed to estimate volumes which can be expected to be added in the

Table 8

Commonwealth Gas Company

1982 and 1983 Added Load Forecast

	1982 (Jan.-Dec.)	1983 (Jan.-Dec.)	Two Year Total
Total Residential-Units	2114	1847	
Sales (MMcf)	335.3	297.7	
Company Conversions			
Units	707	1847	
Sales (MMcf)	111.5	111.9	
Dealer Conversions			
Units	754	392	
Sales (MMcf)	111.7	58.1	
New Homes			
Units	653	744	
Sales (MMcf)	112.1	127.7	
Commercial Sales (MMcf)	567.2	592.0	
Industrial Sales (MMcf)	336.4	359.0	
TOTAL SALES (MMcf) ADDED	1238.9	1248.7	2487.6

SOURCE: 1982 and 1983 Added Lcad Forecast, Response to Document Request D-1(j), Informatior Requests Set 1, November 4, 1982.

residential class with the addition of new customers. The most recent sampling of residential load additions that have been on line for a year was performed in the spring of 1982. Data obtained for these samplings are not retained. For simplicity, these average unit volumes are used both to report actual additions and to forecast additions. Zone 1 Company conversions average 160 Mcf per year; Zone 1 dealer conversions average 150 Mcf per year; and Zone 1 new home additions average 175 Mcf per year. All Zone 2 residential conversions and new home additions average 140 Mcf per year.

In addition to estimates of added loads, the Marketing Department makes estimates of how much of the added loads are base and heat sensitive. These estimates are based on experience and load commitments made at the time the forecast was prepared.

Split-year projections of sales and number of customers by class are shown in Table 9. The forecast shows no load growth between the winter of 1982/83 and the winter of 1983/84. The gas saved by existing customers, calculated at 1 percent of existing customers, is assumed to be resold to new customers as heating gas.

b. Addition of New Load - Normal and Design Year

Load additions forecasted by the Marketing Department for the 1982/83 split-year are added to the normalized 1981/82 monthly sendout by customer class. The same load additions are added to the 1981/82 actual sendout adjusted to reflect design weather conditions. This results in the Company's forecast of normal year and design year requirements, prior to adjusting for large industrial load and the effects of conservation.

Table 9

Commonwealth Gas Company

Projected Sales and Number of Customers

MMcf Sales	1982/83	1983/84	1984/85	1985/86	1986/87
Domestic	20,000	20,000	21,000	22,000	23,000
Commercial	10,641	10,641	11,240	11,920	12,000
Industrial	6,100	6,100	6,300	6,500	6,700
TOTAL	36,741	36,741	37,540	40,420	41,700
No. Customers					
Domestic	184,000	185,400	188,000	193,000	198,000
Commercial	13,800	13,900	14,640	15,500	16,370
Industrial	1,000	1,000	1,100	1,200	1,300
TOTAL	198,800	200,300	203,740	209,200	215,670
Added No. Customers					
Domestic		1,400	2,600	5,000	5,000
Commercial		100	740	860	870
Industrial		-	100	100	100
TOTAL		1,500	3,440	5,960	5,970

SOURCE: Forecast, Section 1, p. 4.

Although the above description of forecasting by the Marketing Department describes a common practice among Massachusetts gas companies, the Council notes that the practise would more properly be described as a forecast of supply, rather than a forecast of demand. The Gas Supply Planning Department identifies new supplies of gas; the Marketing Department assigns and plans to sell these new supplies to customer classes on the basis of very general customer usage information.

A forecast of demand, on the other hand, would proceed in reverse: the forecasting unit would assess customer needs, industrial and commercial growth, demographic changes, improved heating effeciencies and the like, and then notify the Gas Supply Department how much new supply would be needed.

Because our statute prohibits the Council from requiring a demand-based forecast from gas companies, we are constrained from rejecting this supply based format. Nevertheless, increasing interfuel substitution, gas decontrol and the softening of oil prices will force gas companies to look more carefully at demand in the next few years. Generally, companies that invest in excess supplies may find that their systems are strained and their costs expanded.

5. <u>Conservation</u>

The Company assumes that the conservation programs of the state and the federal government, improvements in the efficiency of appliances, price levels and changes in behavioral patterns will result in a one percent reduction in consumption each year by then existing customers. Alternative energy technologies are assumed to have no significant impact on consumption during the forecast period.

The assumptions made regarding energy conservation are the same as those made by the Company in its Fourth Annual Supplement.[19] The forecast assumes that most of the relatively easy, low-cost measures have already been taken and that the more costly measures requiring substantial investments will be phased in gradually as energy prices continue to rise.[20]

The forecast assumes that over the next twenty years there could be a 20 percent decline in energy consumption per customer, for an average conservation rate of 1 percent per year. The Company bases this forecast on judgement.[21] The Company supports its assumption with a study of conservation conducted by the American Gas Association.[22] The study was a survey of gas utility companies' programs and views on key conservation issues.

The study indicated that between 1974 and 1979 gas conservation in the residential, commercial and industrial classes averaged 2.7 percent, 2.2 percent and 1.5 percent per year, respectively. The study projected that during the 1980-1990 period gas conservation would occur at the rates of 1.2 percent, 0.4 percent, and 0.8 percent per year in the residential, commercial, and industrial classes, respectively. It is noted that the conservation described in the survey refers to annual average conservation levels only, and should not be interpreted as peak

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19 Response to Questions SF-1, Information Requests Set 1, EFSC 82-5, November 23, 1982.

20 Response to Question 1, Information Requests, EFSC 80-5, November 2, 1981.

21 Id.

22 See "A Survey of Actual and Projected Conservation in the Gas Utility Industry: 1973-1990"; American Gas Association.

day or seasonal estimates.

The Company, in adjusting for the effects of conservation assumes that the 1 percent figure applies to all customer classes, for each month of the year, and would occur in both a design and a normal year.

The amount of gas estimated to be saved due to conservation efforts is subtracted from the 1981/82 normalized aggregate sales and the figure obtained by adding the forecasted new load. This gives the forecast of normalized aggregate sendout for 1982/83.

The Council questions the use of such a simplistic approach to forecasting conservation by the second largest gas distribution company in the State. As has been noted in past Council Decisions, "the ability to forecast sendout accurately depends on forecasted conservation... conservation is one outcome of a change in customer usage, so that the issue of conservation is a microcosm of the larger issue of customer usage... The key to forecasting conservation accurately is in forecasting usage."[23]

There are several concerns here. First, the Company assumes in its forecast that conservation (by which we mean decreasing customer use factors) by existing customers will occur at a constant rate of one percent in every month of the year. It is unlikely that customers conserve during the heating season in the same manner or at the same rate as they conserve during the non-heating season. As the AGA study on which the Company bases its estimate states, these figures are meant to be average annual rates, not peak or seasonal rates. As the Company

23 7 DOMSC 1, EFSC 80-25 (1982), Boston Gas Company, p. 40.

forecasts sendout requirements on a monthly basis, and not on an annual basis, a more refined and reliable estimate of seasonal conservation is necessary.

Secondly, the Council questions the assumption that all customer classes and customers in both zones conserve at the same rate. Certainly the Company realizes that residential, commercial and industrial customers conserve energy at different rates and for different reasons. For example, what is estimated as conservation in the commercial and industrial classes may in fact be load loss. Although the Company states that it has been unable to separate the effects of economic conditions and conservation from sendout reductions, it recognizes this distinction and has set aside a contingency volume should economic conditions improve and consumption increase.

In addition, conservation will occur at different rates in different zones of the Company's service territory due to different customer mixes. These examples illustrate the need for the Company to understand its customer base and customer usage patterns more completely.

Thirdly, the Council questions the use of the one percent conservation estimate for all years of the forecast period. As has been stated by the Council "(t)his assumes that the conservation rate does not depend on gas prices, the prices of alternative fuels, appliance saturation rates, economic conditions, or some proxy for personal income. Yet, a residential customer's ability to invest in conservation depends on income, an industrial customer's conservation efforts depend on price, and "load loss" rates depend heavily on the relative prices of alternative fuels."[24] It is difficult to accept a conservation estimate that is made independent of all of the variables that influence conservation behavior. The fact that the adjustment is small should not obscure the fact that it is unsubstantiated.

A final concern of the Council's is that in addition to using the one percent conservation estimate in reducing normal year requirements, the Company uses the one percent estimate to estimate the load loss in a design year. This assumes that customers consume at the same rate during design weather conditions as they do under normal weather conditions. This assumption is questionable and requires justification.

The Council stresses the importance of identifying the varying components of conservation, or reduced customer use factors. In past Council Decisions, other companies have been directed to consider certain factors in evaluating conservation including, but not limited to, "behavioral methods of conservation (e.g. reducing thermostat settings) and conservation methods requiring capital expenditures (e.g., efficient water heaters, furnaces and appliances, and insulation) as well as whether the significance of these methods can be expected to increase or decrease over the forecast period."[25]

The Council recognizes that the Company's conservation estimate is based on an external source and not readily adjusted to account for the details discussed above. However, the Council feels it is imperative that the Company develop a reliable, company specific estimate of conservation. The first step towards this end is for the Company to thoroughly understand the factors influencing customer usage. Consi-

24 8 DOMSC, EFSC 82-25 (1982), Boston Gas Company, p. 35.
25 6 DOMSC, EFSC 80-25 (1981), Berkshire Gas Company, p. 5.

dering that conservation "supply" constitutes 28 percent of the supply available to commit to new load over the first two years of the forecast, the reliability of the Company's conservation estimate is of critical importance. Condition 6 addresses the Council's concern in this regard.

The Company prepares a separate forecast of usage by large industrial customers to eliminate the possibility that fluctuations in sales to the large industrial class might cause fluctuations in aggregate sales. It is possible for the Company to make a separate forecast for the large industrial class because the relatively few customers in this class account for a large volume of sales. The Company makes the large industrial forecast by periodically conducting interviews with key accounts to determine their productivity levels and resultant gas consumptions.[26]

The forecast of large industrial accounts is added to the forecast of aggregate sendout to obtain the forecast of normalized sendout for 1982/83.

The 1 percent conservation figure is used to adjust the design year 1982/83 forecast of aggregate sendout. Added to this is the same forecasted large industrial load that is added to the 1982/83 normal requirements. This produces forecasted firm design requirements for 1982/83.

Added to the forecast of normal and design year requirements for 1982/83 is company use, unaccounted for and line loss gas. The Company use and unaccounted for forecast was based on the sum of the Zone 1 and Zone 2 future year forecasts that were submitted in previous forecasts.

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26 Response to Question SF-20, Information Requests Set 1, EFSC 82-5, November 23, 1982.

The Company recognizes the need to refine this estimate in future filings and states that future forecasts will be based on estimates of gas used by the Company (gas which passes through Company meters), the line loss rate (calculated as a percentage of total firm sendout), and estimates of fuel gas requirements for storage gas.[27]

6. Scaling Factors

After the Company develops a forecast of normal and design year requirements a scaling factor is developed that is the ratio of design requirements to normal requirements in each month. These monthly scaling factors are applied to the forecast of normal year requirements for the future forecast years. The monthly scaling factors are shown in Table 10.

For the months of January and February, the number of degree days in a design year are less than the number of degree days in a normal year. Due to this fact, the scaling factors for these two months are less than one. Because it is assumed that no heating use occurs during the summer months, and that normal sendout equals design sendout, the scaling factors for July and August are equal to one.

The Council has one concern with the use of the monthly scaling factors. The scaling factors from year to year will vary depending on the customer class mix and on the usage patterns of the existing and new customers. The use of constant scaling factors assumes that the same mix of customers will exist throughout the forecast period. The Company states that in future forecast years it plans to add 25 percent single family residential, 25 percent multi-family

27 Response to Question SF-15, Information Requests Set 1, EFSC 82-5, November 23, 1982.

Table 10

Commonwealth Gas Company

Scaling Factors for Monthly Design Sendouts

	Non-Heating Season		Heating Season
April	1.203	November	1.145
May	1.278	December	1.186
June	1.00	January	0.9803
July	1.00	February	0.9689
August	1.00	March	1.153
September	1.083		
October	1.059		

SOURCE: Forecast, Section 1, p. 5.

residential, 25 percent commercial and 25 percent industrial load, approximately the same mix that the Company currently has. However, as the Company notes, changing market conditions may require that this split be changed. The temperature sensitivity of the added load will certainly affect the ratio of design to normal year requirements. The Company is cautioned to be aware of this problem.

7. Peak Day Forecast

Peak day sendout is determined as follows. First the normalized base and heating load from the previous January is determined. Second, projected sales for the year are added to provide estimates of the projected base load and heating load for the month. The projected heating load divided by the number of degree days for the month determines the heating factor in use per degree day. The monthly base load and the forecasted large industrial load are divided by the number of days in the month to determine average daily base use and large industrial load. The projected heating load, which is the product of the heating factor and the Company's design degree day standard (64 degree days, using a 59 degree day base) is added to the daily base and large industrial load to determine peak day sendout.

The Company states that because daily sendout and degree day relationships show considerable variability and because the above methodology uses average monthly factors, which eliminates the variations which are likely to occur, the peak day sendout must be adjusted upwards. The Company expects that a peak day would have a higher heating factor than the average day in the coldest month.

This adjustment factor is a judgement based on the variability of the previous year's sendout to degree day relationship and the anticipated variability in the upcoming heating season for such things as changing economic conditions. If the Company is aware that major firm industrial customers are reducing or increasing their gas consumption due to economic conditions, the Company considers these factors in estimating peak day requirements.

The peak day sendout estimate of 308 MMcf for January, 1983, is based on the straight application of the above methodology. Taking all other factors into consideration, the design day sendout for 1982/83 season is 315 MMcf. No further documentation of how these other factors are accounted for in determining peak day sendout in 1982/83 is given.

The Company plans no growth in sales between the winter of 1982/83 and the winter of 1983/84. Rather, the Company plans to resell gas conserved by existing customers to new customers as heating gas. The Company does state that because some of the conserved gas would have been base gas and will be resold as heating gas, peak day requirements will increase. In other words, gas that was previously not temperature sensitive (base) is expected to become temperature sensitive, increasing Commonwealth's peak day requirements. To account for this the Company has increased the peak day sendout for 1983/84 by one percent over the 1982/83 forecasted peak day requirements.

For subsequent years the peak day sendout was determined by how much of the additional load was base and heat sensitive. The specifics of how this was done is not explained by the Company. Table 11 summarizes base, heat and total peak day requirements for the Commonwealth Gas Company.

Table 11

Commonwealth Gas Company

Peak Day Requirements
(MMcf)

	Base Load	Heating Load	Total Requirements
1982/83	-	-	315
1983/84			318
1984/85	63	267	330
1985/86	64	281	345
1986/87	65	293	358

SOURCE: Forecast, Section 1, p. 5-6.

In general, the Council finds that the Company's method for determining peak day sendout is not adequately documented. Specifically, for 1982/83 the Company should outline the derivation of the heating factors used, the derivation of the base load and large industrial load, and the adjustment factor used to increase the heating factor. For 1983/84, the Company should provide further justification for the one percent increase over forecasted peak sendout in 1982/83. For subsequent years, the Company should document its method for determining base load and heating load. All judgements and data used and the method by which such judgements and data are incorporated into the peak day forecast should be explained and documented. Condition 7 addresses these concerns.

A final concern with sendout methodology is the Company's assumption that conservation occurs during the heating season at the rate of 1 percent of existing consumption. Whether the Company makes this conservation adjustment to the monthly sendout data used in calculating peak day requirements is not clear. As discussed earlier, the documentation of the peak day sendout provided by the Company is not sufficient to make this determination. If the average daily figures used by the Company include the conservation assumption, the estimate of peak day requirements could be low, due to the fact that customers are less likely to conserve on very cold days. If they do conserve at all, it certainly will not be at the same rate as during the remainder of the year. The Council cautions the Company to be aware of this when making its forecast of peak day requirements and to explicitly state its assumptions regarding conservation on a peak day in its next filing. Condition 7 also addresses this concern.

8. Summary

The Council finds that the reliability of the Company's forecast methodology could be improved through the development of company specific factors, including base use factors, heating factors for each customer class and territory specific conservation estimates. Conditions 1, 4 and 6 address these concerns.

Also, while the Company's documentation has improved substantially in recent years, in response to Council Decisions and Orders, the forecast review process could be greatly improved by better documentation. Generally, the Company should specifically address those requirements outlined in EFSC Regulations 66.5(a), (b) and (c), including identification of all significant determinants of future sendout and the means, by which they were taken into account, by describing and documenting all data used and the sources of such data, and by stating all significant assumptions made and reasons for making them. Specifically, the Company should document, in its filing, all assumptions regarding price, fuel competitiveness, market conditions, load additions, and all usage factors. Conditions 2, 3, 5, and 7, address these concerns.

III. Commonwealth Gas Company Conservation Programs

Commonwealth has recently submitted to the Council and the Massachusetts Department of Public Utilities a new pilot energy conservation plan.[28] The Company's new plan describes a program to promote and subsidize hot water heater wraps and provide weatherization assistance for residential customers.

The Company plans to begin a general promotional campaign on local radio stations and in local newspapers to help make households aware of their conservation programs.[29] Additionally, the Company is offering specific services and financial incentives for customers to install water heater wraps and low-cost weatherization materials. Table 12 indicates the four separate conservation programs in the COM/Gas conservation plan, along with the Company's estimates of customer participation, program costs (for Commonwealth), and energy savings (for participating customers). The projected costs to Commonwealth for 1983 are $672,200.

In general, the Company's conservation programs appear to be well designed, at least to the extent that they are targeted towards end uses (i.e., hot water heaters and space heating) that are widespread and account for a considerable amount of domestic use.[30] In addition, they constitute relatively low-cost methods for helping participating customers to lower their gas consumption and gas bills. Further, the programs respond to the Council's conditions in its previous Decision and Order that the Company prepare a "demand management strategy that

28 See Pilot Energy Conservation Plan (Draft), Commonwealth Gas Company, September, 1982; and letter from William G. Poist (COM/Gas) to Mass. DPU (dated 11/1/82), regarding DPU Docket No. 871.

29 See Attachments to Poist Letter

30 Water heating represents the second largest amount of energy consumed in the home, according to COM/Gas' Pilot Energy Conservation Plan, p. 8.

Table 12

Commonwealth Gas Company

CONSERVATION PROGRAMS

Program	Eligibility for Program	Maximum No. of Participants	Estimated costs to COM/Gas	Estimated Annual Mcf Savings to Program Participants
1. NO-COST HOT WATER HEATER WRAP (100% subsidy of $22 cost of installed wrap)	All gas water-heater customers who also receive fuel assistance	10,100	$222,200 (at $ 22 installation)	60,600 Mcf (at 6 Mcf per household)
2. LOW-COST HOT WATER HEATER WRAP (50% subsidy of $22 cost of installed wrap)	All gas water-heater customers	10,000	$110,000 (at $11 per installation)	60,000 Mcf (at 6 Mcf per household)
3. WEATHERIZATION SERVICE (installation of low-cost measures purchased by customer at cost)	Participants in Programs No. 1 or No. 2	10,000	- (costs borne by participants)	180,000 Mcf (at 18 Mcf per household)
4. LOW-INCOME WEATHERIZATION (installation of up to $100 worth of measures at no cost to customer)	customers eligible for fuel assistance who also obtain MASS-SAVE audit.	2,650	$265,000 (at maximum of $100 per household)	47,700 Mcf (at 18 Mcf per household)
ADMINISTRATION	-	-	$30,000	-
ADVERTISING	-	-	$45,000	-
TOTAL	-	-	$672,200	348,300 Mcf

SOURCE: COM/Gas, Pilot Energy Conservation Plan (9/82); and Poist letter, Table 1.

includes conservation grants and an installation service."[31]

The Council is concerned, however, that Commonwealth's plan does not adequately fulfill the other parts of the Council's Condition that the Company "discuss the cost-effectiveness of such a strategy to the Company and its ratepayers."[32] The technical documentation that the Company has provided with its plan includes minimal information on how the programs will work, how much the programs will cost the Company and what the programs will mean to participating customers in terms of reduced utility bills. The Company does not explain how it estimated these costs, the energy savings, the dollar value of conserved gas or the level of customer interest or participation in the program. The estimates are therefore difficult to review and their reliability is uncertain and questionable.

For example, the Company expects that fifteen percent of its residential customers with gas water heaters will participate in the wrap programs (No. 1 or No. 2). This level of program participation is nearly four times as high as that of residential gas customers in MASS-SAVE's audit program.[33] Yet, the Company predicts a 15 percent reduction in average annual gas consumption (equal to 18 Mcf) for households that participate in

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31 7 DOMSC 164, at 182.

32 Id.

33 Approximately four percent of gas heating customers obtained a MASS-SAVE audit in 1982. Of those that did get an audit, 62.2 percent subsequently installed insulation on their water heater. See Massachusetts Executive Office of Energy Resources and Executive Office of Community Development, Proposal for Funding the Solar Energy and Energy Conservation Bank (11/82), Appendix A - Housing, Population and Energy Audit Statistics (Table 4).

programs No. 3 or No. 4, even though the Company does not know in advance which weatherization measures the participating customers will install and therefore what amount of gas is likely to be conserved. Unfortunately, the Company doesn't state the assumptions it used in arriving at the 15-percent conservation statistic. Further, without better information on the circumstances under which gas is conserved in homes (e.g., on peak winter days when the Company distributes supplemental fuels, or on fall or spring days at the shoulder of the peak heating season, when the Company is able to sell cheaper stored gas), it seems difficult, if not impossible, to estimate the dollar value of conserved gas.

For these reasons, the Council cannot adequately review the Company's conservation programs and it questions the reliability of the cost and savings estimates. It is impossible to determine whether the programs are cost-effective. Without more detailed information, even the Company cannot achieve its stated goal that it "will monitor and evaluate the results of these pilot programs on a continuing basis and seek new initiatives when appropriate based on experience.[34] To realize this objective, the Company will need to collect detailed data on specific components of offered and implemented programs, participants' characteristics and consumption impacts. These data, along with the development of a methodology for systematically analyzing each program's costs and benefits (both to participating and non-participating customer) will help to enable the Company to evaluate whether each program is worthwhile.

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34 Commonwealth Gas Company, Pilot Energy Conservation Plan, p. 5.

The Company is directed to meet with Council staff to devise a data collection program and methodology for analyzing the costs and benefits of the conservation program, to aid in the Company's analysis of its conservation program and in completely fulfilling Condition 3 of EFSC 80-5. Condition number 8 addresses this concern.

IV. Supply Contracts and Facilities

As do all Massachusetts gas companies, Commonwealth relies on a diverse mix of supplies to provide gas to all its customers. During the non-heating season, when demand is low, essentially all of the gas provided to firm customers by the Company is natural gas transported by pipeline, directly to the Company's distribution system. During the heating season, the Company supplements these supplies with gas stored in underground caverns during the summer months and returned to the Company during the winter as well as natural gas liquefied during the summer and revaporized during the heating season and propane air.

However, Commonwealth Gas is in the unique position of having a very small reliance upon these supplemental supplies, due to the pipeline contracts it has entered into over the years. Over 90 percent of the supply available to the Company for a normal heating season is pipeline gas. Over 82 percent of the supply available for a design heating season is pipeline gas.

In addition, Commonwealth is not dependent upon seasonal shipments of LNG from external sources (such as Distrigas LNG). As is discussed *infra*, the Company liquefies and stores pipeline gas from its firm contracts during the summer months and begins each heating season with enough LNG to carry the Company through the entire heating season.

This section discusses the Company's supply contracts and facilities, including pipeline supplies, storage return gas, LNG and propane.

Since the Commonwealth Gas Company acquired the gas assets of New Bedford Gas and Edison Light Company, supply contracts have been consolidated. Total annual and seasonal volumes can be distributed by the Company as it sees fit, except in the case of SNG where seasonal volumes are still allocated in accordance with the original maximum daily quantities (MDQ's).[35] However, for purposes of forecast review, the Company has allocated annual volumes of pipeline contract to zones according to MDQ's.[36] These allocations are noted where applicable.

A. Pipeline Supplies

The Company currently has three contracts for the supply of pipeline natural gas with Tennessee Gas Pipeline Company (hereinafter "Tennessee") and Algonquin Gas Transmission Company (hereinafter "Algonquin"). It has a fourth contract for the purchase of synthetic natural gas (SNG), delivered by pipeline by Algonquin. In making its forecast of available pipeline supplies, the Company has assumed no curtailments of annual volumetric quantities. This assumption is based upon the best judgement of Company personnel after considering the history of recent years, discussions with suppliers and informal contacts with the industry.[37]

The Company's contract with Tennessee provides for the purchase of 16,858 MMcf, with a maximum daily quantity of 55.4 MMcf. The contract has an expiration date of November 1, 1988, but will continue thereafter unless terminated by either party on twelve months written notice. All of the gas available through this contract is delivered to Zone 1.

The Company's contract with Algonquin under the F-1 rate schedule

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35 See Response to Question S-14B, Information Requests Set 1, November 23, 1982.

36 Id.

37 Forecast, Section 1, pg. 1.

provides for the delivery of 19,165 BBtu.[38] The F-1 contract, allocated to the Company's two service zones according to MDQ's, provides for the delivery of a maximum of 13,822 BBtu to Zone 1 in a contract year and 5343 BBtu to Zone 2. This contract expires on November 1, 1989, and will continue thereafter unless terminated by either party on twelve months written notice.

The Company has a second pipeline contract with Algonquin, under the WS-1 rate schedule, which provides for the delivery of 2,137 BBtu per year, deliverable during the November 16 through April 15 period. This contract has an expiration date of November 16, 1986, but will continue thereafter unless terminated by either party on twelve months written notice. The allocation to zones provides 1,551 BBtu to Zone 1 and 586 BBtu to Zone 2.

The Company has a third contract with Algonquin under the SNG-1 rate schedule. This provides for the delivery of 3,304 BBtu of synthetic natural gas during the November 1 to March 31 heating season. This gas is produced by Algonquin at its plant in Freetown, Massachusetts and is delivered by pipeline. The contract has an expiration date of December, 1987 and will continue thereafter until terminated by either party on twelve months written notice.

The contract provides that the Company may elect to reduce its contractual obligation by up to 50 percent. The Company must elect to do so by June 20 before the start of each heating season. Due to the

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38 The terms MMBtu and BBtu are thermal measures, equivalent to one million Btu's and one billion Btu's, respectively. The term MMcf is a volumetric term equivalent to a million cubic feet. Natural gas is purchased from Algonquin on a therm basis, at the equivalent of approximately 1 BBtu to an MMcf, or 1 MMBtu to an Mcf. Tennessee, until recently, sold gas on a volumetric basis. Future filings will reflect Tennessee gas sales on a therm basis.

operating constraints experienced by Algonquin SNG, Inc. and quantities nominated by other gas companies, Commonwealth has not always received the amount nominated. For the 1982/83 split-year, the Company will receive 2,716 BBtu. The Company estimates that it will receive 2,000 BBtu in all future forecast years.

Algonquin services both Zone 1 and Zone 2 allowing the Company some operating flexibility. Since there are no Company owned, physical connections between the two zones, the Company, on occasion, elects to "share" gas between the two zones, under certain conditions. Providing it causes no problem for Algonquin or any of Algonquin's other customers, it is possible for the Company to back off of pipeline quantities in Zone 1 and substitute LNG in Zone 1 while increasing the pipeline take in Zone 2. It is also possible to increase the pipeline take in Cambridge providing that the take is reduced in the western part of Zone 1 and that increasing the take in Cambridge does not cause any problems for Algonquin or any of its customers.[39]

Table 13 summarizes the terms of the pipeline supply contracts held by the Company.

B. Underground Storage Contracts

The Company has two underground storage contracts with Algonquin and Consolidated Gas Supply Corporation that expire in April, 2000 and August, 2000, respectively. The Algonquin contract is under the STB rate schedule and provides for 600 BBtu of gross storage volume. The maximum daily withdrawal is 6.2 BBtu. The Company has recently amended this contract to provide for firm delivery of gas up to the level of

39 Response to Question S-14, Information Requests Set 1, November 23, 1982.

Table 13

Commonwealth Gas Company

Agreements for Pipeline Gas Supply

Contract	Expiration Date	Maximum Contract Period Volume Zone 1	Zone 2	Total	Maximum Daily Quantity Zone 1	Zone 2	Total
Tennessee CD-6	11/1/88	16,858 MMcf	-	16,858 MMcf	55.4		55.4
Algonquin F-1	11/1/89	13,822	5343	19,165 BBtu	51.2	19.8	71.0
Algonquin WS-1	11/16/86	1,551	586	2,137 BBtu	25.8	9.8	35.6
Algonquin SNG-1	12/87	1,999	1305	3,304 BBtu	13.2	8.7	21.9

UNDERGROUND STORAGE AGREEMENTS

Contract	Expiration Date	Transportation	Annual Storage Quantity Total	Maximum Daily Withdrawal
Algonquin STB	4/2000	Algonquin - Firm up to MDQ	600 BBtu	6.2 BBtu
Consolidated	8/2000	Tennessee - best efforts	905 MMcf	8.2 MMcf

SOURCE: Forecast, Section 3, Tables G-14 - G-24.
Response to Question S-14, Information Requests, Set 1, November 4, 1982.

Commonwealth's MDQ. In the past year only a portion of this was firm. In the previous year, it was all best-efforts delivery.

The Consolidated contract provides for a gross storage volume of 905 MMcf, with a maximum daily withdrawal of 8.2 MMcf. Transportation is provided by Tennessee on a best-efforts basis. The Company has no plans to upgrade this transportation service to firm status.[40] Due to the best efforts status of the transportation of this storage gas, the Company does not rely on this supply on peak days. Table 13, at page 61, summarizes this information.

C. Liquefied Natural Gas (LNG)

As discussed, supra, at 5, the Company's corporate parent, Commonwealth Energy System, is part owner of the Hopkinton LNG Corporation, a subsidiary whose primary business is the liquefaction, storage and vaporization of pipeline supplies for Commonwealth Gas. The Company currently has a contract, expiring in January, 1997, that provides for the liquefaction and storage of 3,500 MMcf of pipeline gas. Natural gas purchased by Commonwealth under its firm, pipeline contracts is liquefied by Hopkinton during the April 1 to November 1 season. The contract also provides for the vaporization of 130 MMcf per day into the Company's distribution system during the winter months. At full design capacity, the Hopkinton facility itself is capable of vaporizing up to 270 MMcf of LNG per day. However, due to the physical limitations of Commonwealth's distribution system, the Company can only take 130 MMcf per day.[41]

40 Response to Question S-8, Information Requests Set 1, November 23, 1982.

41 Response to Question S-7, Information Requests Set 1, November 23, 1982.

The 3500 MMcf of storage provided by Hopkinton consists of three tanks located at Hopkinton, Mass. in Zone 1, with a combined capacity of 3000 MMcf, and two tanks located in Acushnet, in Zone 2, with a combined capacity of 500 MMcf. Pipeline gas liquefied at Hopkinton is put directly into these tanks. The Acushnet tanks are filled with natural gas that is liquefied at Hopkinton and trucked to these tanks prior to the start of each heating season. Of Hopkinton's 130 MMcf per day vaporization service, up to 100 MMcf can be provided at the Hopkinton facility and up to 30 MMCf is available at the Acushnet facility.

D. Propane

Commonwealth owns two propane-air facilities which are used to supplement its gas supplies during periods of peak use. The larger of these is located in Worcester, and has an on site storage of 335,000 gallons (31 MMcf). The facility has a maximum daily design capacity of 14.4 MMcf per day. The second propane air plant is located in Cambridge and has a storage capacity of 155,000 gallons (14 MMcf). The daily design sendout capacity of this facility is 7.2 MMcf per day.

The Company's forecast indicates that the Cambridge plant will be retired after the 1984 heating season. The Company states that the plant will no longer be needed when the new Canadian supplies become available.[42] In the 1981/82 actual split-year the Company produced only 1.3 MMcf from this plant.[43]

E. Future Supply Sources

The Company is a participant in the Trans-Niagara Pipeline and Canadian Gas Import Project. The project proposes the sale of Canadian

42 Response to Question S-2, Information Requests Set 1, November 23, 1982.

43 Forecast, Table G-14.

gas by Pan-Alberta Limited to Trans-Niagara, to be exported at Niagara Falls, New York. Trans-Niagara gas will enter Massachusetts through the Algonquin Transmission Co. pipeline. Commonwealth had signed up for a maximum daily quantity of 21,349 MMBtu, and an annual contract quantity of 7,792,000 MMBtu.

In addition to the sale of Canadian Gas, the Service Agreement also contains a storage component. Commonwealth's portion of the storage had provided for a maximum daily withdrawal of 26,206 MMBtu and a gross storage capacity of 2,620,600 MMBtu. Transportation of this gas was expected to be firm up to the level of Commonwealth's MDQ.

In late January, 1983, the Canadian National Energy Board issued its long awaited decision on that country's natural gas surplus. In that decision, Canada determined that its gas surplus over the next 10-15 years would not be large enough to allow full authorization for every export application that it had received. As a result, virtually every export application - including the Pan-Alberta/Algonquin contract - received authorization for approximately 50% of what had been requested.

This decision, combined with the fact that the Trans-Niagara project has yet to receive any import or facility construction approvals from the U.S. Economic Regulatory Administration or the Federal Energy Regulatory Commission, leaves the current status of these gas imports under a cloud of uncertainty. As such, the Council will base its approval of this Forecast on the assumption that Commonwealth Gas Company will only receive one half of the commodity and storage quantities that were indicated in the Company's forecast. Further, it is assumed that such quantities will not be available until the 1985-86 heating season, contrary to the 1984-85 heating season availability presumed in the Forecast.

The resultant quantities are thus: 13,103 MMBtu of gas deliverable per day, 3,896,000 MMBtu per year and 10,674.5 MMBtu per day storage withdrawal capacity. In the absence of further information, no figures can be presumed for gross storage capacity.

The forecast assumes that the Company will take only 75 percent of the contract quantity of the Canadian gas during the early years of the project, the minimum that can be taken without incurring take or pay provisions.[44] The Company states that "(t)he remaining volumes of gas could be utilized in subsequent years if demand for gas increased to the point where it would be necessary."[45] The Council's Decision does not alter this assumption.

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44 Forecast, Section 1, p. 1.
45 Id.

V. COMPARISON OF RESOURCES AND REQUIREMENTS

The Commonwealth Gas Company, as discussed earlier, is separated into two non-continguous service divisions. Zone 1 encompasses Worcester, Framingham, Dedham, Cambridge and parts of the Cities of Boston and Somerville. The second Zone is in southeastern Massachusetts and includes New Bedford, Plymouth and Fairhaven.

To fully understand the supply and sendout parameters of the Company, requires, to a large degree, viewing each division's resources and requirements as an independent system. Until now, however, the Council has not required companies like Commonwealth to submit separate sets of data for each of its divisions. As such, the staff in this case has had a limited amount of disaggregated data upon which to draw conclusions about the Company's ability to meet the separate requirements of each of its divisions. This has mostly consisted of peak day analyses supplied in response to information requests. In future filings, the Company will be required to supply data that more adequately reflects its divisional realities. It is hereby made an express Condition to the approval of this forecast that Commonwealth submit appropriate disaggregated data on its two zones in all future filings. Council staff will prepare, in consultation with Commonwealth representatives, appropriate forms that the Company should use in fulfilling this Condition. (See Condition No. 9).

A. Normal Year

Commonwealth's supply depth and sendout flexibility generates, on an aggregate basis, an ample ability to meet its system requirements in a normal year scenario. Even assuming that the Company's projected growth in aggregate sales does develop, the annual surplus gas amount over the forecast period ranges from 2.0% to as much as 17.0% (See Table 14). (A breakdown of the Company's normal heating season firm sendout sources is contained in Table 15).

The surpluses, of course, are to be expected. At a minimum we would expect some surplus over normal sendout forecast. The more critical measures of a company's ability to serve its natural gas customers, however, involve the sufficiency of its supplies in time of extreme weather conditions: design year, peak days and cold snaps.

B. Design Year

In a design year, several changes occur in the Company's comparison of resources and requirements. Options on additional quantities of liquid propane and pipeline gas can be exercised and interruptible sales can be cut back. Table 16 shows a comparison of annual design firm sendout with annual design firm supplies for the forecast period.

As is obvious from the table, for every year of the Forecast, the Company has a supply cushion above its aggregate firm design requirements. This result is in spite of the Trans-Niagara adjustments that have been made to reduce the Company's projected supplies for 1984 and beyond. Of course, much remains to be seen with regard to the Trans-Niagara project. As previously noted, the U.S. Federal Energy Regulatory Commission has yet to authorize the construction of the necessary facilities for these imports and the U.S. Economic Regulatory Administration is still considering the pertinent import applications themselves. In addition, the Canadian action to only authorize one-half of the quantities requested by virtually all of the pending natural gas

Table 14

Commonwealth Gas Company

Normal Year Comparisons (MMCF)[1]

	Firm Sendout	Firm Supplies[2]	% Surplus
1982-83	36,491	42,679	17.0
1983-84	37,041	40,129	8.3
1984-85	38,425	39,180	2.0
1985-86	40,286	42,190	4.7
1986-87	42,165	47,269[3]	12.1

1 From Forecast, Table G-22, with noted adjustments.

2 Trans-Niagara supply and related-storage quantities have been reduced by 1/2 - due to the January, 1983 Canadian National Energy Board gas export decision and are assumed to come on line in the Fall of 1985.

3 Although Commonwealth's WS contract with Algonquin is presently scheduled to terminate on 11/16/86, the Council assumes that the parties will exercise their option to renew by then.

Table 15

Commonwealth Gas Company

Normal Heating Season Firm Sendout Breakdown (MMCF)[1]

EXISTING RESOURCES	1982-83	1986-87
Pipeline		
Algonquin		
F-1	9953 (39.6%)	8781 (33.8%)
ST-1	500 (2.0%)	300 (1.2%)
WS-1	1923 (7.7%)	1923 (7.4%)
SNG-1	2716 (10.8%)	2000 (7.7%)
Tennessee		
CD	8109 (32.3%)	8109 (31.3%)
Storage	400 (1.6%)	400 (1.5%)
Supplemental		
LNG Storage	1500 (6.0%)	1500 (5.8%)
Future Supplies		
Trans-Niagara (T.N.)[2]	-	1612 (6.2%)
T-N Storage	-	1310 (5.1%)
TOTAL	25,101 (100%)	25,935 (100%)

1 From Forecast, Table G-22, with noted adjustments.

2 Trans-Niagara supply and related-storage quantities have been reduced by 1/2 - due to the January 1, 1983, Canadian National Energy Board export decision - and is assumed to be available in the Fall of 1985.

Table 16

Commonwealth Gas Company

Design Year Comparisons (MMCF)[1]

	Firm Sendout	Firm Supplies[2]	% Surplus
1982-83	38,660	45,657	18.1%
1983-84	40,358	43,138	6.9%
1984-85	42,590	43,169	1.4%
1985-86	44,710	47,709	6.7%
1986-87	45,962	49,239	7.1%

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1 From Forecast, Table G-22.

2 Trans-Niagara supply and related-storage quantities have been reduced by 1/2 - due to the January 1, 1983, Canadian National Energy Board export decision - and is assumed to be available in the Fall of 1985.

U.S. export applications will necessitate considerable readjustments in the cost calculations involved. Whether the changes will alter the planned purchases of individual customers is an open, albeit speculative, question. Therefore, it is hereby made an explicit Condition of this Forecast Approval that Commonwealth Gas Company provide, beginning April 1, 1983, and every three months thereafter until otherwise agreed upon by the Council staff, a report as to the current status of the Trans-Niagara project and the Company's purchase therefrom (including the associated storage quantity projections). (See Condition No. 10).

C. Peak Day

1. Company Aggregate

The truest test of a gas company's ability to satisfy the requirements of its customers is its capacity to successfully meet its system's peak day needs. 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 product of the maximum rate of firm gas deliveries that a Company is capable of in a single day. The maximum daily rate at which gas can be sent out is in large measure a direct function of the physical limitations of a given system: pipelines, compressors, LNG vaporizers, and propane/air facilities. Facilities that are shared, such as interstate pipelines, also depend on contractual and governmental constraints. Table 17 compares Commonwealth's aggregate peak day sendout capability with the Company's projected requirements over the five years of the forecast period. The table shows that, in the aggregate, the Company's ability to meet its customer's projected peak day requirements is generally adequate. The fact that the Company's excess capacity declines to 1/10 of 1% over peak day requirements in 1985-87 should not cause concern for two reasons. First, a company is not necessarily expected to meet requirements above peak day design. If properly determined, peak day design should by definition, be the maximum sendout rate that a Company should reasonably be expected to provide. However, most companies do not rest on this definition. Rather, they plan to be able to meet design conditions greater than what might be expected on a peak day. The second reason, then, that the reduction in excess capacity is not disturbing relates to the fact that the Council staff has modified the supply projections of the Company. As submitted in its Forecast, Commonwealth projected, e.g., an aggregate peak day sendout rate 6.7% greater than projected requirements. However, this was prior to Canada's decision to reduce the Trans-Niagara volumes by one half. It is arguable that Commonwealth will respond to this development with steps to restore the lost sendout capacity. For example, Commonwealth's basis for shutting down its Cambridge propane/air plant in 1984 is the availability of Canadian gas (See response to Information Request No. S-2, October 21, 1982). If Trans-Niagara were not available until the 1985/86 heating season, it is conceivable that Commonwealth would delay the Cambridge plant's shutdown for a year. In any event, the Company has stated, in response to an early staff question concerning the timing of Canadian gas (Info. Request No. S-11, October 21, 1982) that "It is unclear at this time exactly when the Canadian gas will become available. The Company would not sell the projected volumes until it was certain that the supply would be available."

Table 17

Commonwealth Gas Company

Aggregate Peak Day Sendout Capability and Projected Requirements (MMCF)[1]

	1982-83	1983-84	1984-85	1985-86	1986-87
Pipeline					
Algonquin					
F-1	71.0	71.0	71.0	71.0	71.0
ST-1	6.2	6.2	6.2	6.2	6.2
WS-1	35.6	35.6	35.6	35.6	35.6
SNG	21.9	21.9	21.9	21.9	21.9
Tennessee					
CD	55.4	55.4	55.4	55.4	55.4
Non-Pipeline					
LNG Storage	130.	130.	130.	130.	130.
Propane	21.6	21.6	14.4	14.4	14.4
Canadian					
Trans-Niagara[2] (T-N)	-	-	-	10.65	10.65
T-N Storage	-	-	-	13.1	13.1
	341.7	341.7	334.5	358.25	358.25
Projected Requirements	315	318	330	345	358
Excess Capacity (MMcf)	26.7	23.7	4.5	13.25	.25
As % of Requirements	8.5%	7.5%	1.4%	3.8%	.001%

1 From Forecast, Table G-23, with noted adjustments.

2 Trans-Niagara supply and related-storage quantities have been reduced by 1/2 - due to the January 1, 1983, Canadian National Energy Board export decision - and is assumed to be available in the Fall of 1985.

As a result of the above analysis, the Council's concern with Commonwealth's projected aggregate peak day sendout margins does not warrant a Condition to this approval. However, the Council is anxious to see how the Company's responses to the sendout methodology and Trans-Niagara Conditions of this Decision and Order alter the Company's forecasted peak day margins in future filings.

2. Divisional Analysis

The above noted peak day capacity cushions were the result of an analysis that viewed the Company as a whole.

Due to the fact that the Company serves customers in two non-contiguous service areas, review of the Company's design day sendout capability is not complete without further disaggregation. An overall design day capacity surplus does not, in and of itself, insure that each of the Company's divisions will also have an adequate sendout capability. Table 18 compares Commonwealth's peak day resources and requirements for each of the Company's two zones through the five years of the forecast period. As the following division-specific analysis demonstrates, the Council is also satisfied that each of the Company's two service zones will have sufficient capacity to meet the peak-day requirements of their respective customers

The Worcester/Cambridge Zone (I) of the Commonwealth Gas Company has approximately four times the peak day requirements of its Plymouth/New Bedford zone (II). The data on Table 18 show that, of the two zones, it is Zone I that would nominally experience peak day shortfalls, were current projections to be accurate. The projected deficiencies in sendout capability for Zone I occur in the 1984-85 and 1986-87

Table 18

Commonwealth Gas Company

Divisional Peak Day Resources and Requirements[1] (MMcf)

	1892-83		1983-84		1984-85		1985-86		1986-87	
Pipeline	I[2]	II	I	II	I	II	I	II	I	II
Algonquin										
F-1	51.2	19.8	51.2	19.8	51.2	19.8	51.2	19.8	51.2	19.8
ST-1	6.2	-	6.2	-	6.2	-	6.2	-	6.2	-
WS-1	25.8	9.8	25.8	9.8	25.8	9.8	25.8	9.8	25.8	9.8
SNG	13.2	8.7	13.2	8.7	13.2	8.7	13.2	8.7	13.2	8.7
Tennessee										
CD	55.4	-	55.4	-	55.4	-	55.4	-	55.4	-
Non-Pipeline										
LNG Storage	100	30	100	30	100	30	100	30	100	30
Propane	21.6	-	21.6	-	14.4	-	14.4	-	14.4	-
Canadian[3]										
Trans-Niagara (T-N)	-	-	-	-	-	-	10.65	-	10.65	-
T-N Storage	-	-	-	-	-	-	10.1	3	10.1	3
	273.4	68.3	273.4	68.3	266.2	68.3	286.95	71.3	286.95	71.3
Projected Requirements	255	60	257	61	267	63	280	65	291.0	67
Excess Capacity	18.4	8.3	15.4	7.3	(.8)	5.3	6.95	6.3	(4.05)	4.3
As % of Requirements	7.2	13.8	6.4	12.0	(.3)	8.4	2.5	9.7	(1.4)	6.4

1 From Company's response to Staff Information Request No. 14-B (October 21, 1982).

2 Columns "I" and "II" refer to Commonwealth's service Zone I and II, as they have been described in the text.

3 T-N is assumed to be available in Fall of 1985 at 1/2 the previously anticipated amounts.

split-years. These capacity rates are .3% and 1.4% below projected sendout requirements, respectively. Again, these projected shortfalls do not occur in the Company's submitted data, due to the more recent export ruling of the National Energy Board of Canada. This divisional disaggregation, then, highlights even further the critical importance of the Company's compliance with Condition No. 10 to this approval.

It should be noted that the Company has attempted to reassure the Council staff on this point. In both of the seasons in question ('84-'85 and '86-'87), there are capacity margins in Zone II that could conceivably make up the reduced sendout rates in Zone I. Were the Company able to reallocate some of its gas from the more secure Zone II to Zone I on a peak day basis without effecting its projected sendout rate in Zone II, the forecasted Zone I shortfalls could be averted. In response to staff information requests on this matter, the Company replied that such capability is in fact in place. In response to Staff Information Request S-14A (October 21, 1982), the Company explained that both of its zones are served by the Algonquin Pipeline Company. "This allows the Company to share gas under certain conditions." But upon follow-up questioning concerning possible peak-day problems for Algonquin that might interfere with this "sharing", Commonwealth stated that it "is not dependent upon Algonquin's operating flexibility with respect to transfers of gas between Commonwealth's two zones in order to meet peak day and cold snap requirements. Both Zones 1 and 2 are able to meet their peak day requirements without the displacement arrangement". (Staff Information Request No. IR-2-18 (December 14, 1982)). Unfortunately, this does not seem to be the case. As such, it is hereby made a Condition to this Approval that Commonwealth Gas Co., in its next filing, demonstrate more explicitly how it intends to meet its peak day requirements on a zone basis, either through sufficient peak day sendout capability in each zone or by explaining more fully what reliable and firm means are in place for shifting supplies on a daily basis from one zone to another without reducing the sendout rate of the transferring zone. (See Condition No. 11).

Outside of this last concern, the Council is satisfied that Zone II has sufficient peak day sendout capacity through the forecast period, ranging from 6.4% to 13.8% above forecasted requirements.

D. Cold Snap

The Council has defined a, so-called, "cold snap" as a prolonged series of days at or near peak conditions, similar to the two-to-three week period experienced during the 1980-1981 heating season. The Company's ability to meet such a "cold snap" is related to both its ability to meet design heating season requirements and its ability to meet peak day sendout requirements. It is similar to design heating season requirements in that the Company must demonstrate that the aggregate resources available to it are adequate to meet such a large sendout. On the other hand, it is similar to peak day sendout in that the Company must show that it has, and can sustain, the capacity to deliver large daily loads.

Viewed simply as a matter of the relationship between peak day sendout capabilities and storage capacity, the Company appears to be well situated for managing a "cold snap". For example, the availability of LNG, which is generally regarded to be the critical "cold snap" supply source, seems quite sufficient. LNG, if stored at or near capacity levels, could be sent out at the Company's maximum peak day rate (130 MMcf/day) for 27 days.

However, the ability to meet an unexpected "cold snap" at any given time during the heating season depends on a number of factors, including the weather experienced to date, as well as supply management and planning and facility capacities.

The Council recognizes that, for the 1982/83 heating season, the Company does have both the capacity to meet design peak day sendout requirements and the resources to meet design heating season sendout. The prudent management of these resources by, for example, assuring that LNG inventory levels are at all times sufficient to meet peak shaving needs under remaining design winter conditions, appears feasible. The Company's almost exclusive reliance on pipeline gas and the vaporization of stored LNG has placed it in an enviable position with regard to meeting the demand of a "cold snap". This position was amply demonstrated in the winter of 1980-1981 when Commonwealth was able to assist several other Massachusetts gas companies to meet their sendout requirements. (See DPU Order No. 555 at pages 159-160 and response to Staff Information Request No. S-13, October 21, 1982). However, the Council is concerned that the Company explain and demonstrate its ability to cope with future cold snaps on a divisional basis. As such it is a Condition to this approval that in future filings the Company should specifically address this concern, and demonstrate both the availability of resources and its sendout capacity to meet such cold snap conditions in each of its Service Zones (See Condition No. 12).

VI. Hopkinton LNG Corporation

Hopkinton LNG Corporation is jointly owned by the Commonwealth Energy System and Air Products and Chemicals, Inc., a corporation otherwise unrelated to Commonwealth Energy System. Hopkinton obtains technical and other similar services from Commonwealth Energy System Company, a subsidiary of Commonwealth Energy System, and utilizes certain employees of the Commonwealth Gas Company in preparing its forecast.

As discussed previously, Hopkinton owns LNG storage facilities consisting of five above-ground consolidated storage tanks and associated liquefaction and vaporization equipment located in Hopkinton and Acushnet, Massachusetts. Commonwealth Gas Company owns the gas and purchases the liquefaction, storage and varporization services discussed, *supra* at pages 55-56, from Hopkinton. Hopkinton neither owns nor sells any of its own gas.

Hopkinton LNG does not intend to construct new facilities during the forecast period and given the above facts the Council unconditionally APPROVES the Hopkinton LNG Corporation's Second Long-Range Forecast.

VII. DECISION AND ORDER

The Council hereby conditionally APPROVES the Second Long-Range Forecast of Gas Resources and Requirements of the Commonwealth Gas Company and ORDERS:

1. That the Company begin to develop service territory-specific monthly base use factors. With its next filing, the Company should either incorporate this data into its forecast or present a satisfactory long-term plan for the development of this data and its incorporation into the forecast.

2. That the Company thoroughly document the normalization process in its forecast methodology. Specifically, the Company should describe and document the use of the regression results and any pertinent information obtained from this analysis.

3. That the Company provide thorough support for its use of a 59 degree day base in place of the standard 65 degree day base. The Company should submit any formal studies or empirical evidence supporting the use of a 59 degree day base instead of the 65 degree day base.

4. That the Company begin to examine the data available to it in deriving heating use factors by customer class. The Company should report, in its next filing, on its efforts to date and its future plans for incorporating this data into its forecast.

5. That the Company continue to monitor the anticipated impacts of natural gas price decontrol on its forecast of sendout. This analysis shall include projected sendout data for each

class, anticipated marketing strategies to ensure both a reliable and least cost supply of gas, and anticipated problems with customer accounts receivable. The Company shall also address the anticipated impacts upon interruptible and dual-fuel customers and explain how this is incorporated into the forecast.

6. That the Company actively endeavor to collect and analyze territory specific data that assesses the conservation potential, in terms of decreasing customer use factors, by class and according to time of use, i.e., during the non-heating and heating seasons and on peak days. Given the time requirements involved and resources available to the Company, the Council recommends that the Company develop a long-term data collection plan and implement this plan in scheduled, low-cost phases.

7. That the Company more thoroughly document its forecast of peak day requirements, including any data and assumptions used regarding base and heating use, the effect of conservation supplies upon peak day sendout, and the means by which these data and assumptions are incorporated into the forecast.

8. That the Company meet with Council staff to develop a data collection program and methodology for analyzing the costs and benefits of its conservation program, to aid in the Company's analysis of its conservation program and in completely fulfilling Condition 3 of EFSC 80-5.

9. That the Company submit appropriate disaggregated data on its two zones in all future filings. Council staff will prepare, in consultation with Commonwealth representatives, appropriate forms that the Company should use in fulfilling this Condition.

10. That the Company provide, beginning April 1, 1983, and continuing every three months thereafter, until otherwise agreed upon, a report on the current status of the Trans-Niagara project and the Company's purchase therefrom (including the associated storage quantity projections). The Company should also provide, in its next filing, an explanation of the customer classes and service zones for which these Canadian supplies are targeted, including whether the targeted customers constitute new or existing load and to what extent the Canadian gas will be used to reduce the use of higher priced supplemental gas supplies.

11. That the Company, in its next filing, demonstrate more explicitly how it intends to meet its peak day requirements on a zone-specific basis, either through sufficient peak day sendout capability or by explaining more fully what reliable and firm means are in place for shifting supplies during peak day conditions from one zone to another without affecting the sendout capacity of the transferring zone.

12. That the Company, in its future filings, give a detailed, zone-specific explanation of how it plans to meet its customers' sendout requirements during a "cold snap".

The Council hereby unconditionally APPROVES the Second Long-Range Forecast of Gas Resources and Requirements of the Hopkinton LNG Corporation.

Lawrence W. Plitch, Esq.
Hearing Officer

On the Decision:

Juanita Haydel, Lead Analyst
Susan Fallows, Staff Economist

This Decision was approved by a unanimous vote of the Energy Facilities Siting Council on February 28, 1983 by those members and designees present and voting: Chairperson Sharon M. Pollard; Stephen Roop (for Secretary Evelyn F. Murphy); James Brenner (for Secretary Paula W. Gold); David Shutz (for Secretary James S. Hoyte); Richard A. Croteau; Harit Majmudar; and Thomas J. Crowley.

March 3, 1983

Date

Sharon M. Pollard
Sharon M. Pollard
Chairperson