Decisions and Orders

Massachusetts Energy Facilities Siting Council

Volume 10

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COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Colonial Gas Company for Approval of the Second Long-Range Forecast with First Supplement of Gas Resources and Requirements

EFSC No. 82-61

FINAL DECISION

James G. White, Jr., Esq.
Hearing Officer

On the Decision:

Margaret Keane, Lead Analyst

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I. Procedural History

Colonial Gas Company (Colonial) filed its Second Long-Range Forecast and First Supplement with the Energy Faciities Siting Council (Council) on August 13, 1982.[1] The filing contained the Forecasts of both the Lowell and Cape Cod Divisions. No new facilities, as defined in M.G.L.A. ch. 164, sec. 69G, were proposed. On August 20, 1982, the Hearing Officer issued a "Notice of Adjudicatory Proceedings". Colonial provided proper Notice of the proceeding by publication in local newspapers and posting in Town Halls. No petition to intervene was received.

On September 20, 1982, Colonial submitted an errata sheet to its filing. One day later, on September 21, 1982, a pre-hearing conference was held. A technical session was held at the offices of Palmer & Dodge, Colonial's legal counsel, on October 19, 1982, and was attended by Council Staff and representatives of both the Lowell and Cape Cod Divisions of Colonial. A second technical session was held at the offices of the Lowell Division on January 25, 1983. The Cape Cod Staff did not attend.

1 By agreement between Colonial Gas Company (Colonial) and the Hearing Officer, the 1981 Forecasts were not required because decisions on the 1980 Forecasts of Lowell Gas Company and Cape Cod Gas Company were not until issued March 15, 1982, and May 5, 1982, respectively. In Re Lowell Gas Company, 7 DOMSC 207 (1982); In Re Cape Cod Gas Company, 7 DOMSC 183 (1982). In order to keep the submissions of Long-Range Forecasts on track with other gas companies, it was agreed that Colonial's present Forecast should be the Second Long-Range Forecast with First Supplement.

II. General Introduction

Effective July 30, 1981, Colonial Gas Energy System, the former parent company of Lowell Gas Company and Cape Cod Gas Company, merged with them to form one operating utility under the name Colonial Gas Company. Colonial Gas Company now operates a Lowell Gas Division and a Cape Cod Gas Division. Colonial also has a subsidiary named Transgas, Inc., a common carrier of propane, liquefied natural gas and other cryogenic fuels.

Prior to 1982, the Lowell and Cape Cod Gas Companies presented separate forecasts. In August 1982, the Colonial Gas Company submitted a Second Long Range Forecast with First Supplement on behalf of its Cape Cod and Lowell Divisions.

Colonial states that, "wherever possible the forecast methodology and general descriptive sections have been consolidated for the two divisions. In the future, it is anticipated that any differences in methodology will be eliminated except in those instances where they are necessary because of customer load characteristics."[2]

The Council recognizes that the operating characteristics of the two Divisions are very different, in some cases necessitating different forecasting approaches. However, the Council encourages the Divisions to work closely together to develop a unified planning method and to facilitate the sharing of expertise.

As stated in the past, the Council generally expects to see Company resources dedicated to forecasting needs and requirements in

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2 Forecast at 1.

proportion to the size of the Company.[3] In the future, the Council will expect a somewhat greater level of sophistication from a joint Lowell and Cape Cod filing than it would from separate filings.

The Divisions have achieved measurable levels of progress since their last filings. As EFSC 80-16 and 80-19 imposed numerous conditions on each Division, and as the two forecasts were presented separately for purposes of this filing, they will be reviewed separately.

The Divisions' 1982 Forecasts are subject to review criteria as stated in EFSC Rules 62.9(2)(a), (b) and (c), which call for the use of accurate and complete historical data and a reasonable statistical projection method. In its review of a Forecast, the Council determines whether a projection method is reasonable according to whether the methodology is (a) appropriate or technically suitable for the size and nature of the particular gas utility's system, (b) reviewable or presented in a way that results can be evaluated and duplicated by another person given the same information, and (c) reliable, that is, provides a measure of confidence that its assumptions, judgements and data will forecast what is most likely to occur. The Council applies these criteria on a case-by-case basis.

In essence, the two Divisions utilize very similar methodologies for forecasting sendout. As the Company has noted, the disparate load characteristics of the Divisions may preclude complete adoption of a a uniform methodology.[4] The Company does set forth a description of its

3 See In Re Fitchburg Gas and Electric Company, 7 DOMSC 238, 241 (1982).

4 Cape is roughly 63% residential, whereas Lowell is roughly 50% residential and 50% commercial/industrial.

general methodology on page 2 of the Forecast. It is as follows:

1. Estimating customer growth by classification based upon historic sales statistics, taking into consideration population growth in the towns, building activity, customer saturation and economic conditions.
2. Determining annual and peak day base load and heating load consumptions based upon historic load characteristics adjusted for trends that would include consumers' conservation of energy, utilization of new appliances and price of product.
3. Determining the availability of supply of pipeline natural gas and supplemental gas and utilizing these resources with maximum effort towards providing least cost mix to our customers.
4. Analyzing the capacity of existing gas manufacturing and vaporization facilities on the Company's system and estimating Company use and unaccounted for gas in relation to determined consumption projections.

Steps 1 and 2 will be discussed within the context of each individual Division's sendout Forecast, while steps 3 and 4 will be discussed on the supply side.

III. Cape Cod Gas Division Sendout

A. Introduction

The Cape Cod Gas Division ("Cape Cod" or "the Division") serves approximately 38,314 customers in Wareham, Bourne, Falmouth, Sandwich, Mashpee, Barnstable, Yarmouth, Dennis, Brewster, Harwich, Chatham, and

Orleans. Total firm Company sendout in 1981-82 was 4822 MMcf. The Division represents roughly 2.6% of Massachusetts gas sales. Cape Cod's annual gas sales are broken down as follows: residential with gas heating 60%; residential without gas heating, 2%; commercial, 35%; (See Table 1). The current forecast projects an annual growth rate of 0.75% in total firm sendout during the forecast period.

The Division's Fourth Annual Supplement to its Long Range Forecast was approved subject to the following conditions:

1. That the Company provide in its next filing the historical data used to estimate base use, heating use, and average use factors in each customer class and describe the manner in which this data was used in the forecast.

2. That the Company explain any judgements made concerning future energy use per customer, the basis for said judgements and the manner by which such judgements are incorporated into the forecast in the next filing.

3. That the Company document its methodology for estimating design year sendout requirements for the five years in its next forecast, including: (a) explicit and separate treatment of base load and temperature sensitive load, (b) its derivation of the MCF/DD factors used in estimating design year sendout requirements and (c) an explanation of any judgement factors used in this analysis.

Table 1

Cape Cod Division

Sendout by Customer Class[1]
(MMcf)

	1982-83		1986-87	
	Heating Season	Non-Heating Season	Heating Season	Non-Heating Season
Residential				
Heating	1,834	1,014	1,917	1,042
Non-Heat	42	86	46	92
Commercial	949	645	976	631
TOTAL	2,825	1,745	2,939	1,765

1 Forecast Tables G-2 and G-3 at C20-C25.

4. That more explicit documentation of the Company's contingency plans in the event of an unforeseen cessation of any of its major supplemental supplies coupled with a prolonged period of peak-like days be included in the next forecast.

5. That the Company provide in its next Forecast an evaluation of a demand management strategy that includes conservation grants and an installation service. The evaluation should discuss the cost-effectiveness of such a strategy to the Company and its ratepayers.

6. That the Company file its Second Long-Range Forecast on July 1, 1982.

7. That the Company arrange a meeting with the Council Staff to discuss the above conditions within 30 days of this decision.

Conditions 1, 2 and 3 have been answered to the Council's complete satisfication and are representative of a large amount of effort on the Division's part, for which the Division is to be commended. Conditions 4, 5, 6 and 7 have also been satisfied.

B. Normal Year

A "normal year" is defined as a year that is neither warmer nor colder than average. Cape Cod took a 20 year arithmetic average of actual degree day data and arrived at a normal year of 6561 degree days. Weather Services in Bedford provide the Company with data from three locations on the Cape.

The Company forecasts its normal year sendout requirements as in the following example:

1982 Non-heating Season

"Net Number Customers X base load factor = Base Load

Net Number Customers X heat load factor (MCF/EDD)S X Normal EDD

= Normal Heat Load

Base Load + Heat Load = Normal Sendout

Non-heating season

The same formula is then applied to the Heating Season to obtain total split-year sendout for this class."[6]

C. Base Load Factors

Base load factors and projections of number of customers are determined for each individual class.

Cape Cod analyzes five years of base load data for trends. (See Table 2). The base load factor for the residential heat class is an average of Mcf per bill consumption for July, August and September. The Division states that it expects to see a decline in base load consumption because "the addition of more new customers, in conjunction with

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

6 Forecast at C4.

the loss of existing market and replacement of older units, creates a turn-over of a percentage of this equipment to newer, more efficient base use appliances on an annual basis."[7] Cape Cod also studied base load patterns for new customers and found average MCF/customer/year usage to be 18% below that of existing customers. In light of this, the Division has judgementally projected an annual decline of roughly 2% per year.

The residential without heat class is analyzed in line with the varying consumption patterns exhibited by customers on the seasonal and year round rate tariffs. The Division uses the GS (seasonal) and GY (year round) rate tariffs as a basis for separating Mcf/customer use, and breaks those figures into seasonal components. Thus, the Division was able to determine that GY consumption has been declining, while GS consumption has been rising. Total consumption in this class, which accounts for 2% of total sendout, is projected to increase by 0.20 Mcf/customer/year.

In the commercial sector, the Division expects usage factors to remain constant in 1982-83 and decline by 3% annually thereafter. This is based on Cape Cod's premise that "continued implementation of more efficient base use appliances will occur, particularly in the event of any rise in prices."[8]

Demand from Otis Air Force Base is expected to remain constant and Cape Cod is volumetrically recording daily sendout to confirm this.

D. Heating Load Factors

As with base load factors, Cape Cod calculates heat load factors by

7 Forecast at C6.
8 Forecast at C12.

Table 2

Cape Cod Division

Average Annual Use Per Residential Customer[1]

Residential Classes

	Heating: Base Use (MCF/year/Cust)	Heating: Heating Use (MCF/degree/cust) day	Non-heating: (Base)
Historical			
1977-78	38.7	.0099	19.7
1978-79	37.4	.0098	19.4
1979-80	34.1	.0111	18.7
1980-81	33.6	.0104	21.0
1981-82	33.6	.0099	21.2
Forecast			
1982-83	32.8	.0098	21.4
1983-84	32.1	.0097	21.6
1984-85	31.3	.0096	21.8
1985-86	30.6	.0095	22.0
1986-87	29.8	.0094	22.2

1. Base Use figures expressed as MCF/year. Heating use figures expressed as MCF/degree day.

customer class. These were calculated based upon data from the last five heating seasons, in conjunction with company judgement and American Gas Association (AGA) studies.

In the residential heating category, the Division has experienced a downward trend since the high experienced in 1978-79 and expects this decline to continue throughout the forecast period. Cape Cod attributes this to "increased conservation, appliance efficiency and any increase in gas costs," stating that "this assumption is supported by in-house studies and external forecasts."[9]

The Division has also observed a 6% decrease in new customer use per effective degree days from .0099 to .0093.

In the commercial sector, the Division has witnessed fluctuations from .0316 Mcf/customer/EDD in 1980-81 to .0248 Mcf/customer/EDD in 1977-78 with a five year average heat load factor of .0283.

Cape Cod states, "[i]t is the Division's experience that conservation trends in commercial businesses are not as clearly defined as in the residential sector." The Division cites AGA studies noting, these "'primary' or low-cost conservation measures largely took effect between 1973-79 for commercial establishments, and that while the potential does exist for structural improvements and retrofits here, these more costly measures are less likely to be implemented by businesses concerned with short-term profit margins."[10]

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9 Forecast at C6.
10 Forecast at C13.

Thus, the Division chose to forecast commercial heat load factors as constant at .0283 for the heating season and .0127 for the non-heating season, based on the average of the last 5 years.

E. Conservation

Cape Cod measures conservation through its forecasts of use factors by customer class. The Division states that it anticipates "that rising prices will affect customer use of gas appliances, as well as having the increased efficiency of new appliance installations reduce consumption. Attempts were made to project this conservation where applicable." [11]

The Division is encouraged to closely monitor the impacts of rising prices on its sendout and to attempt to identify base and heat load conservation separately.

F. Design Year

A "design year" is defined as the coldest year for which a company plans to meet its firm customer requirements. The Division used a design year consisting of 7403 effective degree days based on data from September 1961 to August 1981.

Design year sendout is forecast in the same way as normal year sendout with one notable exception. The Division's analysis of historical data indicates that heating use is higher during design conditions, which it attributes to its residential customers who make up 77% of total winter sendout. Because of this, the Division uses .011 Mcf/customer/EDD (its January heat factor) as a design year heat load factor rather than the .0098 mcf/customer/EDD figure used for forecasting normal year sendout requirements.

11. Forecast at C3.

G. Peak Day

A "peak day" is the coldest day that is likely to occur during a twelve month period. The Division used a peak day of 77 Effective Degree Days, which is the coldest day experienced by the Cape Cod system in twenty years.

Peak Day Sendout was calculated in the same way as normal sendout. The Division stated that it broke base use factors into use per day factors and used the average January Mcf/customer/EDD for five years as heat load factors. The Council finds use of January factors to be appropriate, however, it instructs the Company to provide further documentation of its method of calculating daily base use factors. In its next filing, the Division is instructed to justify continued use of a five year average in light of changing usage patterns or to develop a new figure.

H. Number of Customers

Based on historic growth patterns and market estimates of new construction, the Division projects that it will add 1000 new residential heat customers annually and lose 245 customers annually for a net annual gain of 755 customers.

The Division believes this is realistic in light of projections of 2,500 to 3,000 new construction building starts annually. They also state that gas prices approaching or exceeding parity with oil could conceivably lead to increased marketing efforts in this area.

Cape Cod mentions that increased marketing efforts were made in the residential without heat class to prevent further erosion of decline in the number of customers in this class. Cape Cod continues to say "[i]n the past year, this effort resulted in the addition of 85 new customers to this classification, up from an average of 50 for the previous five years."[12] The Council encourages the Division to closely monitor growth and to report to the Council on any consequent changes in its marketing policies.

I. Conclusions

The Council finds the Cape Cod Division's sendout methodology to be reviewable, reliable and appropriate. The Division is commended on the many refinements to its methodology that have been incorporated since its Fourth Supplement. The Division is encouraged to continue refining its methodology.

IV Lowell Division Sendout

A. Introduction

The Lowell Gas Division ("Lowell" or "the Division") serves approximately 49,746 customers in Lowell, Billerica, Chelmsford, Dracut, Dunstable, North Reading, Pepperell, Tewksbury, Westford, Wilmington and Tyngsboro. Lowell's total firm sendout in 1981-82 was 10,898.9 MMcf. The Division represents roughly 5.5% of Massachusetts gas sales. Lowell's annual gas sales are roughly 50% residential and 50% commercial/industrial. The current forecast projects a growth rate of approximately 2% per year. (See Table 3).

Lowell's Fourth Annual Supplement to its Long Range Forecast was approved subject to the following conditions:

1. That conservation projections for new and existing residential customers be documented, separately, in the Company's next Forecast.

2. That the Company explain any judgements made concerning

12 Forecast at C8.

Table 3

Lowell Gas Division

Sendout by Customer Class
(MMcf)

	1982-83 Heating Season	1982-83 Non-Heating Season	1986-87 Heating Season	1986-87 Non-Heating Season
RESIDENTIAL				
Central Heat	3,322.30	1,488.89	3,294.41	1,504.23
Space Heat	483.73	220.22	315.06	109.12
Non-Heat	57.00	82.01	41.77	60.61
COMMERCIAL/IND'L (firm)	3,314.18	1,604.13	4,155.17	1,925.96
INTERRUPTIBLES	113.31	509.92	113.31	509.92
COMPANY USE/ UNACCOUNTED FOR	531.52	(5.19)	531.52	(9.48)

conservation, the basis for said judgements and the manner by which said judgements are incorporated into the forecast in the next filing.

3. That all projected annual use per customer factors used to prepare the forecast for normal sendout be further quantified and documented in the next Forecast.

4. That the Company explain how it derived the figures in Table G-1 for split-year Heating Use Per Customer Per Degree Day, and Split-Year Base Use per customer, for the forecast years.

5. That the Company document its methodology for estimating design year sendout requirement for the five years in its next Forecast, including: (a) explicit and separate treatment of base load and temperature sensitive load, (b) its derivation of MCF/DD factors used in estimating design year sendout requirements, and (c) an explanation of any judgement factors used in this analysis.

6. That more explicit documentation of the Company's contingency plans in the event of an unforeseen cessation of any of its major supplemental supplies be included in the next Forecast.

7. That the Company provide in its next Forecast an evaluation of a demand management strategy that includes conservation grants and an installation service. The evaluation should discuss the cost effectiveness of such a strategy to the Company and its ratepayers.

9. That the Company arrange a meeting with the Council staff to discuss the above conditions within 30 days of this decision.

On the Sendout Side, Conditions 1, 2 and 7 have been complied with and will not be discussed further. The Council's concerns with Conditions 3, 4, and 5 are discussed infra at pages 20-24 and concerns with Condition 6 are discussed infra at 56.

B. Sendout Forecast

The Division states that it used the following methodology, except where noted, to project sendout for all classes:

"1. Estimate the number of net customer changes for each year of the forecast.

2. Use historical data base and trend the use per customer over the forecast period for base load and heat load factors.

3. Verify trends using existing and estimated market conditions and management judgement.

4. Spread base load evenly over the 12-month period (except where noted in a particular customer class).

5. Spread heat load over the 12-month period using 20 year average degree days.

6. Multiply the monthly base load and heat load per customer by the number of customers to get total monthly heat and base use.

7. Add heat load and base load to get total load."[13]

Within this series of steps, the Council is primarily concerned with the Division's development of customer use factors and customer growth projections, figures which form the crux of any reliable forecasts.

EFSC 80-16 Conditions 3, 4, and 5 required the Company to further quantify and document its customer use factors. While it appears that

13 Forecast at L4.

the level of forecasting sophistication at issue here has moved forward, the issue of reviewability is still at hand. The Council appreciates the large quantity of data submitted, but requests a more coherent and detailed explanation of how and why these data were used in the future. Procedures used by the Cape Cod division should be utilized to identify use factors for each customer class, and for both base and heating use.

C. Normal Year

Normal year weather is based on an arithmetic average of 20 years of degree days, while design year and peak day are based on the coldest actually experienced in 20 years. Thus normal year is 6,136 degree days, a design year is 6,808 degree days, and peak is 67 degree days.

The Lowell Division forecasts normal year by rate classification, using the general method outlined supra at 18, which is similar to that used by Cape Cod.

The Division adjusted its base load figures to adjust for customers who turn pilots off on central heating systems. The July and August base loads, estimated historically, are then subtracted from total annual base load, with the rest allocated evenly from September to June.

While this adjustment may accurately reflect usage patterns in Lowell's service territory, it is by no means clear to the Council how the Division calculated base load. Documentation for the residential space heating and residential without gas heat classifications, as well as Information Response LDS-5 refer back to page L-4 of the Forecast for an explanation of the methodology used to calculate both base and heat load factors. The documentation provided on page L-4 is not reviewable, however.

As can be seen from Figure 1 (Residential Central Heat) the Division used historical data to produce trend lines to forecast base use and heat load factors for each customer class. The Division provides no explanation of how base and heat loads have been calculated from total load historically. Further, given its historical performance, it is far from clear that the trend lines representing H-2 (residential space heat) and H-3 (Residential Central Heat) base load use are at all reliable. Residential heat and space heating heat factors, based on four and two years of data, respectively, also lack credence. Use of two years of data used in the residential non-heat category does not inspire confidence in the reliability of the Forecast.

This is of particular concern in light of the widely divergent forecasts of base and heat use. (See Table 4.) The Division seems to have attributed all conservation efforts to heating use without having documented its rationale.

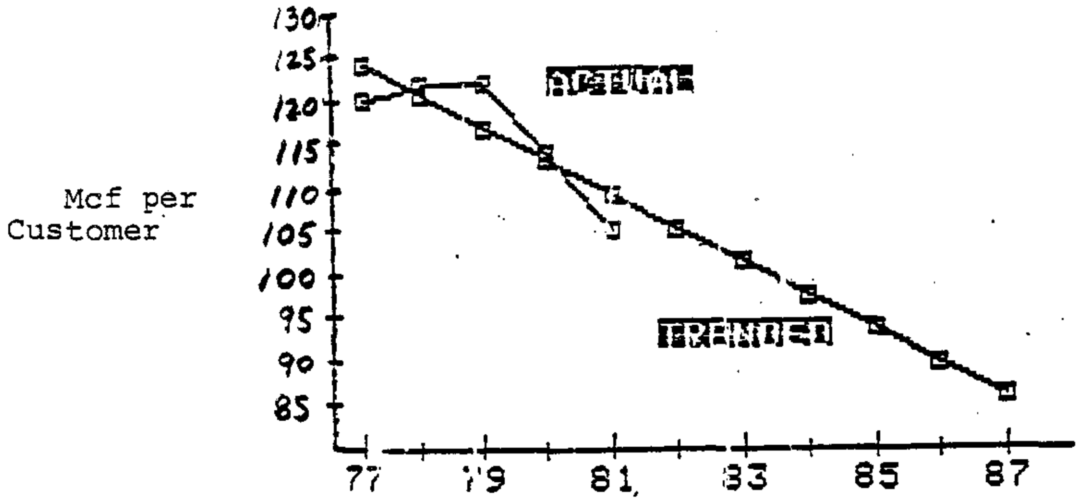
Use per customer figures were not calculated for the Commercial and Industrial (CO) rate, due to the wide variance of usage within this group. The Division used a regression model, based on data from 1978 on, to calculate annual load increases.

Actual usage figures from June 1981 were used to reflect base load. Base load was multiplied by twelve and subtracted from total use to arrive at the heating component of load. New base and heat load additions were allocated on a 30/70 basis in accord with historical experience.

Annual heat and base load were spread over the year. Increases to the heating segment are allocated in accord with the 1980-81 data base. Heat load and base load are then added; customer additions are estimated

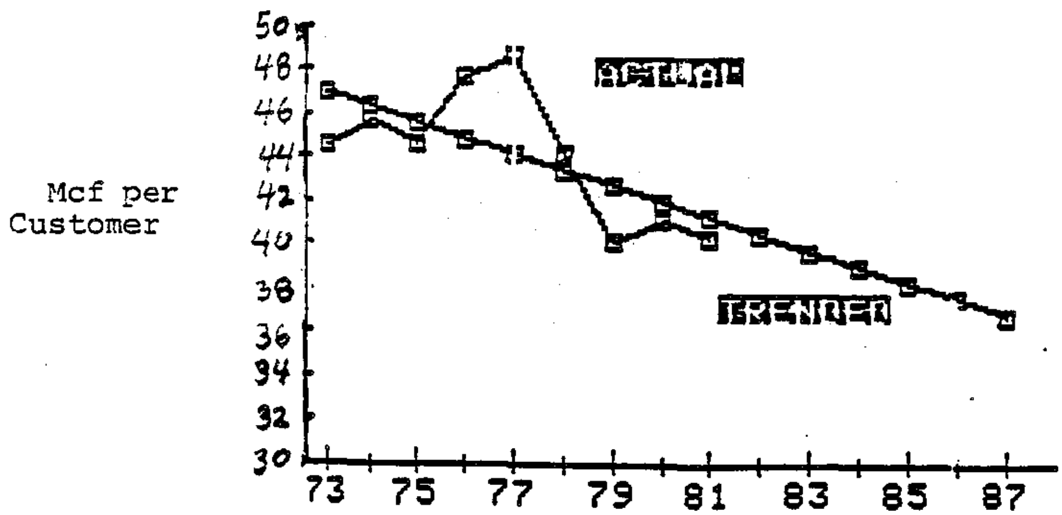
Figure 1

H-3 HEAT LOAD PROJECTICH



YEAR
1977-1981 ACTUAL HEAT LOAD/CUST
1982-1987 TRENDED HEAT LOAD/CUST

H-3 BASE LOAD PROJECTION



YEAR
1973-1981 ACTUAL BASE LOAD/CUST
1982-1987 TRENDED BASE LOAD/CUST

Source: Forecast Charts 2-3

Table 4

Lowell Gas Division

Average Annual Use Per Customer[1]

RESIDENTIAL

	Central Heating		Space Heat		Non-Heat
	Base Use	Heat Use	Base Use	Heat Use	
Historical					
1977-78	49.4	.019	27.9	.012	23.9
1978-79	43.4	.02	24.4	.013	24.9
1979-80	40.62	.02	23.6	.013	25.21
1980-81	39.30	.0198	23.46	.0133	25.66
1981-82	40.5	.0178	25.44	.0124	27.14
Forecast					
1982-83	41.35	.0173	26.33	.0114	25.06
1983-84	41.00	.0164	28.06	.0105	24.82
1984-85	40.38	.0158	29.45	.0091	24.41
1985-86	40.11	.0153	32.08	.0075	24.54
1986-87	39.76	.0150	34.12	.0068	24.35

1. Base Use Figures expressed as Mcf/year. Heating use figures expressed as Mcf/degree day.

and spread evenly over 12 months. The final base load figure is calculated by dividing base loads by number of customers.

EFSC 80-16 expressed concern with the potential for loss of existing customers and declining customer use. The Division forecasts an increase in Company sendout on the order of 1,163 MMcf over the forecast period. The Council questions this growth assumption in light of the prices of oil and gas.

To the Council's knowledge, at least two of Lowell's firm customers (St. John's Hospital and the University of Lowell) have already converted to No. 6 residual oil.[14] The Council's concern has only increased since then. In its next filing the Division is conditioned to provide a basis for future Company growth projections, not based on historical trends.

The Council is fully aware that the Division has made a good faith effort at complying with both the spirit and Conditions of the previous Decision and greatly appreciates this cooperative attitude. Unfortunately, the Council does not feel the results of the Division's efforts to comply with conditions 3, 4, and 5 are either reviewable or reliable. The Division is hereby ORDERED to meet with Council Staff within 60 days to discuss remedies for the next forecast.

D. Customer Projections

Customer projections are also projected from trend analysis of historical data. In Information Response LDS-7, the Division stated it incorporated judgement into the trend analyses. In its Forecast, the Division states that it has performed a study of the past ten years of growth and market saturations in its service territory, using 1980

14 Response to Information Request CGS-4.

Census data and Company records. The study estimated growth projections by town, based on total buildable land, estimated potential gas housing units, and estimated gas units per year, among other data. The Company compared its projections with the results of its study and stated "the conclusion drawn from the comparison supports the forecasted growth rates used in the long term forecast."[15] The Division is lauded for its efforts in this area. However, in light of increased gas prices relative to oil, the Company is instructed to reevaluate these estimates. As with other companies in the Commonwealth, the Council reminds the Company that the era of deregulation is one of uncertainty and one where past trends cannot necessarily be expected to continue. The Council is particularly concerned about the potential loss of dual-fuel customers and has addressed this concern in Condition One.

E. <u>Design Year</u>

All design year consumption above normal year sendout is assumed to occur in the heating component of load. The ratio of design degree days to normal degree days is applied to heating load on a split year basis.

For example:

RESIDENTIAL WITH CENTRAL HEAT[16]

Non-Heating $\frac{1{,}573 \text{ DD's}}{1{,}347 \text{ DD's}} = 1.141$

Heating $\frac{5{,}271 \text{ DD's}}{4{,}789 \text{ DD's}} = 1.101$

Given that the Council is uncertain about Lowell's allocation of

15 Forecast at L1.
16 Forecast at L6.

total sendout between base and heat use as it is, the Division is instructed to provide firm documentation for its assumption that all design use occurs in the heating component of its load.

F. Peak Sendout

The Division calculates peak load sendout as follows:

1. Derive base load by adding forecasted January base loads by rate class and dividing the sum by 31 days. This figure is adjusted to compensate for company use.
2. This base load figure is subtracted from total January Company sendout to arrive at the monthly heating component. This is divided by 1,181 DD's and results in an MCF/DD figure.
3. This MCF/DD figure is then multiplied by 67 DD to arrive at the peak day heating component and added to base load to equal total peak day sendout.

As previously mentioned, the Council has concerns with the Division's computation of base load. In the future, the Division is instructed to document its method of calculating base load. Lowell should also consider the possibility of using an MCF/DD figure higher than the January average and report the results of its analysis to the Council. See Condition 2.

G. Conclusion

The Division's forecast of sendout is an improvement on the filing submitted in EFSC 80-16. The Company has made some progress at complying with Conditions 3, 4, and 5, but it must upgrade its documentation to meet reviewability standards. The Division is ORDERED to meet with Council Staff to discuss a method for continuing the incremental forecast improvements made with respect to these conditions, with the intention of improving forecast reviewability and incorporating concerns pertinent to the rapidly changing natural gas market. See Condition 3.

V Supply Contracts and Facilities

Colonial relies on a diverse mixture of natural gas supplies to meet its demand requirements. During the non-heating season when demand is low, both Divisions of Colonial rely primarily on gas purchased from pipeline suppliers to meet the requirements of their firm customers. These supplies are introduced directly into the distribution systems of both Divisions. During the heating season, and to a lesser degree during the non-heating season, the direct pipeline supplies of both Divisions are supplemented with gas stored in underground caverns, vaporized LNG, and propane air. In addition the Lowell Division supplements its pipeline supplies with supplies from Boston Gas, while the Cape Cod Division's supplies are supplemented with synthetic natural gas (SNG).

Beyond these generalities, however, the gas supply characteristics of the two Divisions are quite different. As separate companies, each developed its own sources of pipeline supplies and supplemental supplies. Due to the absence of a pipeline interconnection between the Divisions, the only flexibility in shifting supplies between the Divisions is provided by LNG and propane which can be shipped by truck and stored at different locations. Thus, the supply characteristics of the two Divisions are analyzed separately.

A. Cape Cod Division

1. Pipeline Supplies

Cape Cod has two agreements with Algonquin Gas Transmission for firm pipeline supplies of natural gas. Cape Cod has a third agreement for the purchase of SNG delivered by Algonquin. Additionally, Cape Cod has assumed, based on its successful past experience and business judgement, that deliveries of propane will be available to replenish storage and meet forecast requirements.[17]

The agreement with Algonquin for firm service (F-1) provides for the purchase by Cape Cod of a maximum annual quantity of 3071 MMcf and a maximum daily quantity of 11.3 MMcf.[18] The contract has an expiration date of November 1, 1989, but will continue thereafter until terminated by either party on twelve months written notice.

The agreement with Algonquin covering firm winter pipeline supplies (WS-1) provides for the delivery of 288 MMcf a year with an average daily quantity of 3.2 MMcf and a maximum daily quantity of 4.8 MMcf.[19] These supplies are deliverable during the period November 16 through April 15, inclusive, of each year. The agreement has an expiration date of November 16, 1989, but will continue thereafter until terminated upon twelve months written notice of either party.

Cape Cod's third agreement with Algonquin involves firm deliveries of SNG (SNG-1). This agreement provides for deliveries of 614 BBtu[20] of SNG during the November 1 to March 31 heating season.[21] The gas is

17 Forecast at C17.

18 Reply to Information Request Question CGC-2, "Service Agreement" between Algonquin Gas Transmission Company ("Algonquin") and Cape Cod Gas Company (Cape Cod) dated December 11, 1972.

19 Reply to Information Request Question CGC-2, "Service Agreement" between Algonquin and Cape Cod dated December 11, 1972.

20 The terms MMBtu and BBtu are thermal measures equal to one million Btu and one billion Btu's respectively. The term MMcf is a volumetric quantity equal to one million cubic feet. Cape Cod purchases gas from Algonquin on both a volumetric and therm basis at an equivalent of approximately one BBtu to an MMcf. The tables in the Forecast comparing resources and requirements alter the contract quantities to account for the Btu content of the pipeline supplies.

21 Reply to Information Request Question CGC-2, "Service Agreement" between Algonquin and Cape Cod dated July 8, 1977.

produced by Algonquin SNG, Inc. at its plant in Freetown, Massachusetts and is delivered by Algonquin Gas Transmission. The agreement has an expiration date of September 20, 1987, but will continue thereafter until terminated by either party on twelve months written notice.

Cape Cod pays for SNG under the terms of Algonquin Gas Transmission's Rate Schedule SNG-1 filed with the Federal Energy Regulatory Commission. Under the terms of this tariff, Cape Cod requested a reduction of its firm SNG quantities for the 1982-83 winter season. Cape Cod states that this contract will be reviewed annually. For purposes of the Forecast through 1986-87, however, Cape Cod utilized an allocation reduced to 50 percent of contract quantities, or 307 MMBtu per year.[22]

2. <u>Underground Storage Agreements</u>

Cape Cod has one underground storage agreement (STB) with Algonquin which expires on April 15, 2000. The agreement provides for 700 BBtu of annual storage capacity, with a maximum storage demand of 10 BBtu per day. Only 3 BBtu of the daily storage demand is firm.[23] An increase in the firm storage quantity is negotiable, and Cape Cod is considering possible increases in terms of cost effectiveness. Beyond the current firm levels, however, daily deliveries are on a best efforts basis and are not relied upon in the Forecast for peak day deliverability.[24] Table 5 summarizes the terms of Cape Cod's pipeline supply and underground storage agreements.

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22 Forecast at C17; Table G-24. The SNG-1 tariff allows SNG customers to reduce their takes to less than the contract demand provided the net reduction of all customers allows a net operating capacity of 50% of daily capacity during the winter season.

23 Response to Information Request Question CGC-2, "Service Agreement" between Algonquin and Cape Cod dated September 1, 1981.

24 Forecast at C17.

Table 5

Cape Cod Division

Pipeline Supply and Underground Storage

Service Agreement	Expiration Date	Maximum Contract Period Volume	Maximum Daily Quantity
Algonquin F-1	11/1/89	3126 MMcf[1]	11.57 MMcf[1]
Algonquin WS-1	11/16/89	293 MMcf[1]	4.88 MMcf[1]
Algonquin SNG-1	9/30/87	307 BBtu[2]	4.0 BBtu
Algonquin STB (storage)	4/15/2000	700 BBtu (max. storage capacity)	10.0 BBtu 3.0 BBtu (firm)

1. The volumetric figures are based on a thermal content of pipeline gas as shown in Forecast Tables G-22 at C34-C43.
2 The Figure of 307 BBtu represents the reduced allocation of approximately 50% under the terms of Algonquin's Tariff SNG-1.

3. Liquefied Natural Gas

The Cape Cod Division has LNG storage and vaporization facilities at South Yarmouth and Wareham, Massachusetts. The facilities have respective storage capacities of 189.4 MMcf and 8.4 MMcf.[25] These two facilities have maximum daily design sendout capacities of 28.8 MMcf and 2.4 MMcf respectively. Additionally, Cape Cod has a storage service agreement with Algonquin LNG, Inc. for LNG storage service in Providence, Rhode Island which expires on May 31, 1992. The agreement with Algonquin LNG provides for a storage capacity of 10,500 barrels of LNG (36 MMcf) through May 31, 1987, and 12,000 barrels (42 MMcf) from June 1, 1987, through May 31, 1992. Under the terms of the agreement, Cape Cod can withdraw the stored LNG upon request.[26] The agreement does not specify any limitations on quantities which can be requested by Cape Cod.

Cape Cod purchases LNG from Bay State Gas Company under an agreement dated August 1, 1979. The agreement has an expiration date of March 31, 1988, but will continue in force thereafter until terminated on at least twelve months written notice by either party. The agreement provides for monthly firm volumes of 76 BBtu for the months of April through October in each contract year. Monthly firm volumes for the months November through March in each contract year increase yearly from 90.2 BBtu for the 1982-83 heating season to 109.2 BBtu for the 1987-88 heating season. In addition the agreement provides for the purchase of monthly optional volumes for the months of January, February and March of each year. The monthly optional volumes increase from approximately

25 Forecast Table G-14 at C29.

26 Response to Information Request Question No. CGC-2, "Service Agreement" between Algonquin LNG, Inc. and Cape Cod dated June 30, 1982.

50 BBtu in 1983 to approximately 60 BBtu in 1988.[27] The purchase of these volumes is at Cape Cod's option on ten days notice prior to the month in which the gas is to be made available. The table below[28] summarizes the volumes available under the Bay State agreement.

Contract year	(BBtu) Firm Volume	(BBtu) Optional	(BBtu) Total
4/82 - 3/83	527	149	676
4/83 - 3/84	546	155	701
4/84 - 3/85	565	161	726
4/85 - 3/86	584	167	751
4/86 - 3/87	603	173	776
4/87 - 3/88	622	179	801

4. Propane

Cape Cod has three propane-air units which are used to supplement gas supplies during periods of peak use. These facilities are located at Cataumet, South Yarmouth, and Chatham, Massachusetts. The table below[29] indicates the capabilities of these facilities:

Location	(MMcf) Max. Daily Design Capacity	(MMcf) Storage Capacity
Cataumet	4.8	22.5
South Yarmouth	3.0	11.0
Chatham	1.9	5.5
	9.7	39.0

27 Response to Information Request Question CGC-2, "Agreement for Sale of Gas" between Bay State Gas Company and Cape Cod dated August 1, 1979. Cape Cod can elect to take the gas in the form of propane, although the normal supply is in the form of LNG. Cape Cod is responsible for the truck transportation of this LNG.

28 Forecast at C-46, Supplement to Table G-24.

29 Forecast Table G-14

The Cape Cod Division states that it assumes necessary quantities of propane will be available for purchase. Colonial contracted with Petrolane Northeast Gas Service, Inc. for the firm delivery of 200,000 gallons (22 BBtu) and 300,000 gallons (33 BBtu) during the months of January and February 1983 for the Cape Cod Division.[30] During the 1981-82 heating season, the Cape Cod Division sent out 67 MMcf of propane, or approximately two percent of total sendout.[31]

5. <u>Future Supply Sources</u>

Cape Cod currently is negotiating with Algonquin for delivery of approximately 4-5 MMcf per day of Canadian gas beginning in 1984-5.[32] Cape Cod, however, did not include these volumes in its Forecast because the negotiations are not final.[33]

The Cape Cod Division is a participant in the Trans-Niagara Pipeline and Canadian Gas Import Project. As part of the proposed project, Canadian gas will be sold by Pan-Alberta Limited to Trans-Niagara, to be exported at Niagara Falls, New York. Trans-Niagara gas will enter Massachusetts through Algonquin's pipeline. Under a Precedent Agreement between Algonquin and Cape Cod, Cape Cod's maximum daily quantity is specified as 4,589 MMBtu.

In late January 1983, the Canadian National Energy Board issued its long-awaited decision on Canada's natural gas surplus. Canada

30 Response to Information Request Question CGC-2, "Products Sales Contract" between Colonial and Petrolane Northeast Gas Service, Inc. dated October 4, 1982.

31 Response to Information Request Question CD-5.

32 Response to Information Request Question CGC-2, Precedent Agreement between Algonquin and Cape Cod dated August 2, 1982. The Precedent Agreement states that Cape Cod will not utilize storage service offered by Algonquin associated with the Canadian gas.

33 Forecast at C16.

determined its gas surplus over the next 10 to 15 years would not be large enough to allow full authorization for every export application received. As a result, virtually every export application, including the Pan-Alberta/Algonquin contract, received authorization for approximately 50 percent of the requested volumes. This decision, combined with the fact that the Trans-Niagara project has yet to receive any import or facility construction approvals from the Economic Regulatory Administration or the Federal Energy Regulatory Commission, leaves the current status of these gas imports under a cloud of uncertainty.

While, the Cape Cod Division does not rely on Canadian gas in its Forecast, Cape Cod states such supply would improve significantly its supply situation and allow further reduction of use of supplementals.[34]

6. Comparison of Resources and Requirements of Cape Cod Division

a. Normal Year

The Cape Cod Division, given its supply and sendout flexibility, possesses the ability to meet its firm system requirements in a normal year scenario. Even assuming Cape Cod's growth in aggregate sales does develop, Cape Cod possesses an annual surplus of gas above the amount required to meet projected firm sendout over the forecast period. As demonstrated in Table 6, Cape Cod has demonstrated an annual surplus over normal firm sendout ranging from 8.1 percent to 11.1 percent. The surpluses 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 during extreme weather conditions including a design year, peak days and cold snaps.

34 Forecast at C16.

Table 6

Cape Cod Division [1]

Normal Year Comparisons (MMcf)

	Firm Sendout	Firm Supplies	Percentage Surplus
1982-83	4880	5423[2]	11.1
1983-84	4922	5349	8.7
1984-85	4960	5385	8.6
1985-86	4995	5410	8.3
1986-87	5026	5436	8.1

1 Forecast Tables G-4 and G-22 with noted adjustments. Firm Supplies reflect a 50% reduced allocation of (from 614 to 307 BBtu) of SNG for each of the contract years. Firm supplies, however, reflect optional volumes of LNG available from Bay State Gas Company but do not reflect any Canadian gas.

2 Includes 55 BBtu of propane under contract for 1982-83 heating season, and 120 Btu of LNG and 26 MMcf of propane which Cape Cod had in storage on April 1, 1982. Response to Information Request Question CD-5. Additional LNG volumes of 120 MMcf are included due to a postponement of deliveries which caused volumes to be received in 1982-83 split-year. Table G-22 at C34.

b. Design Year

Table 7 shows a comparison of annual firm design sendout with annual firm supplies.

Table 7

Cape Cod Division

Design Year Comparison (MMcf)

	Firm Sendout[1]	Firm Supplies	Percent Surplus
1982-83	5446	5525[2]	1.5
1983-84	5515	5656	2.6
1984-85	5586	5693	1.9
1985-86	5651	5717	1.2
1986-87	5715	5743	0.5

1 Forecast Table G-4; Response to Information Request Question CD-4.

2 Figure for 1982-83 includes existing storage as of April 1, 1982, of propane and LNG; includes additional 120 MMcf of LNG received in summer 1982 due to a postponement of deliveries; includes 55 MMcf under existing propane contract; includes 102 MMcf of interruptible gas already received from Algonquin.

Table 7 indicates that Cape Cod had a surplus of gas for each design year in the Forecast Period.

Table 8 shows Cape Cod's design year heating season resources for the 1982-83, 1983-84, and 1986-87 heating seasons. The full allocation of SNG is 614 BBtu was included for 1983-84, and 1986-87, whereas the 50 percent allocation of 307 BBtu was used for 1982-83. In each instance, Table 8 reflects a large surplus of gas available for a design heating season. Cape Cod did not rely on its full allocation of SNG in its Forecast. Nevertheless, Table 8 indicates that there is approximately a 5 percent surplus over design requirements for the 1983-84 and 1986-87 heating seasons if Cape Cod receives only a 50 percent allocation.

Cape Cod's projected surplus with reduced volumes of SNG is accomplished in part by assuming the Division will be able to obtain small quantities of interruptible gas for normal year non-heating season sendout.[35] This practice allows Cape Cod to maximize its storage levels in planning for a design winter. The Council does not believe this assumption is unreasonable. In essence, Cape Cod's comparison of resources and requirements in its Forecast does not consider the impact of a design winter on the supply available in ensuing years.[36] Thus, Tables 7 and 8 were compiled on the same premise. Were the Division to experience design weather conditions, the forecasted storage levels presumably would be depleted. The Division would be required to refill storage in the ensuing non-heating season to prepare for the possibility of another design winter. In so doing, Cape Cod would rely, to some

35 Cape Cod states that based on past experience these volumes will be available. Forecast at C17.

36 Forecast Tables G-22 at C34-C43.

Table 8

Cape Cod Division

Design Year Heating Season Firm Resources (MMcf)

	1982-83	1983-84	1986-87
Algonquin F-1	1616	1641	1666
STB	672	650	586
WS-1	293	293	293
SNG	307	614	614
Propane	77	99	174
LNG	875	841	905
	3790	4138	4238
Forecast Design Sendout	3599	3660	3723
Percentage Surplus	5.3%	13.1%	13.8%
		4.7% (with 50% SNG)	5.6% (with 50% SNG)

degree, on the availability of propane and interruptible supplies from Algonquin. Additionally, Cape Cod has certain flexibility in regard to its allocation of SNG. The Council is satisfied that Cape Cod would make the necessary adjustments as part of its supply planning to have sufficient supplies for another design year.

d. Peak Day

The truest test of a company's ability to satisfy its requirements is the capacity to meet its peak day needs. Peak day sendout is a product of the maximum firm rate of deliveries by a company in a single day. The maximum firm rate is a direct function of the physical characteristics of the particular system. In addition, contractual and governmental restraints on interstate pipelines also affect the peak day sendout. Table 9 compares Cape Cod's aggregate peak day sendout capability with the projected peak day requirements over the next five years. Table 9 reveals that Cape Cod has ample peak day sendout capability.

Table 9

Cape Cod Division

Aggregate Peak Day Sendout Capability and Projected Requirements[1] (MMcf/day)

	1982-83	1983-84	1984-85	1985-86	1986-87
Pipeline					
Algonquin F-1	11.57	11.57	11.57	11.57	11.57
WS-1	4.88	4.88	4.88	4.88	4.88
STB	3.00	3.00	3.00	3.00	3.00
SNG-1[2]	2.99	4.00	4.00	4.00	4.00
Non-Pipeline					
Propane	9.70	9.70	9.70	9.70	9.70
LNG Storage	31.20	31.20	31.20	31.20	31.20
	63.34	64.35	64.35	64.35	64.35
Projected Requirements[3]	44.00	44.90	45.80	46.70	47.60
Excess Capacity	19.34	19.45	18.55	17.65	16.75
As % of Requirements	43.9	43.3	40.5	37.8	35.2

1 Forecast Table G-23 at C44 with noted adjustments.
2 Maximum Daily SNG quantity is the actual allocation for 1982-83 and the contract quantity for following years.
3 Forecast Table G-5 at C28.

d. Cold Snap

The Council has defined a "cold snap" as a prolonged series of days at or near peak conditions, similar to the two-to-three week period experienced in Massachusetts during the 1980-81 heating season. A company's ability to meet a cold snap is related to its ability to meet both peak day sendout requirements and design heating season requirements. A company must demonstrate it has aggregate resources available to meet a large sendout, and the capacity to deliver large daily loads. Generally, a company's ability to meet a cold snap is related to its storage of LNG. As demonstrated in the previous section, Cape Cod clearly has the ability to deliver daily loads above its daily design requirements.

Further, as demonstrated in the Table below, in the 1982-83 heating season, and 1983-84 heating season the Cape Cod Division can meet a cold snap of peak day deliveries lasting twelve consecutive days by receiving the maximum daily contracted pipeline deliveries assuming full storage quantities of propane and LNG.

Cape Cod Division

Cold Snap - Daily Deliveries (Mcf/day)

	1982-83 Heating Season	1983-84 Heating Season
Algonquin F-1	11577	11577
WS-1	4886	4886
ST-1	3000	3000
SNG	2991	4000
	22454	23463
Propane	3077 (12.67 days)	3062 (12.73 days)
LNG	18467 (12.67 days)	18374 (12.73 days)
Peak Day Requirements	43999	44899

In compliance with Condition 4 in the Council's most recent decision on Cape Cod, In Re Cape Cod Gas Company, 7 DOMSC 183 (1982), the Cape Cod Division submitted a section on contingency planning for an unforeseen cessation of major supplemental supplies coupled with a prolonged period of peak-like days.[37] Cape Cod's analysis was similar to, but less stringent than the foregoing analysis on the Division's ability to meet a cold snap which assumed a series of consecutive peak days. Cape Cod analyzed its ability to meet requirements for a hypothetical nineteen day period in a hypothetical month of February with severe weather based on the historic month which had the highest effective degree day differential over the design year effective degree days for the same month. Cape Cod's analysis indicates its ability to meet its requirements in such a period under several supply cessation scenarios. The Council commends the Division on this analysis.

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37 Forecast at C47-C53.

B. Lowell Division

1. Pipeline Supplies

Lowell has one contract with Tennessee Gas Pipeline Company for firm deliveries of pipeline supplies. The contract provides for a contracted demand (CD-6) of 34.68 MMcf per day.[38] The annual volumetric limitation (AVL) is 10,732 MMcf.[39] The contract has an initial expiration date of November 1, 2000, but will continue in effect thereafter until cancelled on twelve months written notice of either party. In addition to direct deliveries into Lowell's distribution system, supplies from Tennessee also are used to fill Lowell's contracted underground storage with Penn-York Energy Corporation.

2. Underground Storage Agreements

Lowell has an underground storage agreement with the Penn-York Energy Corporation for storage of gas in Pennsylvania.[40] The agreement provides for an annual storage quantity of 2,000 MMcf. The maximum rates for injection and withdrawal of gas into and from storage depend on the percentage of the annual storage quantity which is occupied. When the percentage of annual storage quantity occupied is between 30 and 100 percent, the maximum withdrawal quantity is 18.182 MMcf per day. When the percentage of annual storage quantity occupied is between zero and 10 percent, the maximum withdrawal quantity is 13.333 MMcf per day.

38 Response to Information Request Question CGC-2, "Gas Sales Contract" between Lowell Gas Company and Tennessee Gas Pipeline Company dated March 1, 1981. The prior contract between Lowell and Tennessee was scheduled to expire in November 1988. In Re Lowell Gas Co., 7 DOMSC 207, 230 (1982).

39 Response to Information Request Question CGC-3.

40 Response to Information Request Question CGC-2 "Underground Storage Service Agreement" between Lowell and Penn-York Energy Corporation dated May 21, 1981.

Lowell has two contracts with Tennessee for the transportation of underground storage gas. One contract provides for a firm maximum injection into storage and transportation out of storage of 15.69 MMcf per day (SST-NE). Previously, storage return volumes had been transported by Tennessee on a best efforts basis. In Re Lowell Gas Company, 7 DOMSC 207, 290-31 (1982). Lowell determines the storage injection and withdrawal quantities on a daily basis. The daily quantity of gas injected into storage is deducted from the amount of gas deliverable under Rate Schedule CD-6.[41] The firm transportation contract has an expiration date of March 31, 1995, but will continue in effect until cancelled on twelve months written notice. Lowell also has a contract with Tennessee for interruptible deliveries of underground storage gas (ISST-NE).[42] This contract provides maximum interruptible daily injection and withdrawal quantities of 2.49 MMcf per day. Again, daily quantities of gas injected into storage are deducted from the daily volumes deliverable under Rate Schedule CD-6. This contract has a primary term ending on March 31, 1999, but will continue in force thereafter until cancelled by either party on twelve months written notice.[43] Table 10 summarizes Lowell's pipeline supply and underground storage agreements.

41 Response to Information Request Question CGC-2, "Storage Service Transportation Contract" between Lowell and Tennessee dated May 26, 1981. Lowell is charged 4.49 percent of the withdrawal volume for fuel use by Tennessee.

42 Response to Information Request Questions CGC-2, "Interruptible Storage Service Transportation Contract" between Lowell and Tennessee dated May 26, 1981.

43 The contract may terminate earlier if Tennessee ceases to sell gas to Lowell under existing gas sales contracts.

Table 10

Lowell Division

Pipeline and Storage Volumes

Service Agreement or Contract	Expiration Date	Maximum Contract Period Volume	Maximum Daily Quantity
Tennessee CD-6	11/1/2000	10732	34.68 MMcf
Penn-York Storage	Earlier of 3/31/95 or FERC Order	2000 MMcf (storage capacity)	-
Tennessee SST-NE	3/31/95	-	15.69 MMcf
Tennessee ISST-NE	3/31/95	-	2.49 MMcf

3. Liquefied Natural Gas

The Lowell Division has LNG storage and vaporization facilities at Tewksbury, Westford, and Wilmington. The Tewksbury facility also has liquefaction capability.[44] The following table summarizes the capabilities of these facilities.

Lowell Division

LNG Facilities

	Maximum Design Daily Capacity	Storage Capacity
Tewksbury		
Liquefaction	4.6 MMcf	
Vaporization	64.8 MMcf	1080 MMcf
Westford		
Vaporization	7.8 MMcf	54 MMcf
Wilmington		
Vaporization	7.2 MMcf	23 MMcf
	79.8 MMcf (vaporization)	1157 MMcf

On April 1, 1983 Colonial will commence the purchase of LNG for its Lowell Division from Bay State Gas Company under an Agreement dated September 24, 1982.[45] The contract provides for the purchase of 600

44 The Tewksbury facility is leased from Aerojet General Corporation. Forecast Table G-24.

45 Response to Information Request Question CGC-2, "Agreement for Sale of Gas" between Colonial and Bay State Gas Company dated September 24, 1982.

BBtu of firm supplies and 400 BBtu of optional supplies from April through October of each year of the contract, which expires March 31, 1988. Colonial must exercise the option by May 1st of each year. The exact contract quantities are provided in Table 11.

Table 11

Lowell Division LNG Purchases from Bay State

Contract Year	Period	(MMBtu) Firm Volume	(MMBtu) Option Volume	(MMBtu) Total Volume
April 1, 1983 -	April	86,000	0	86,000
March 31, 1984	May	86,000	67,000	153,000
through	June	86,000	67,000	153,000
April 1, 1987-	July	86,000	67,000	153,000
March 31, 1988	August	86,000	67,000	153,000
	September	85,000	66,000	151,000
	October	85,000	66,000	151,000
	November-March	0	0	0
	TOTAL	600,000	400,000	1,000,000

Previously, Lowell had contracted for LNG on a yearly basis. Lowell's contract with Bay State for the period of November 1, 1981, through October 31, 1982, provided respectively for 950 MMcf and 500 MMcf of firm and optional supplies.[46]

4. Boston Gas

In the past, Lowell has purchased small quantities of gas on a best efforts basis from Boston Gas under yearly contracts through the existing interconnection on the Littleton-Westford line.[47] The most recent contract covering the period December 1, 1982, through April 15, 1983, provided for a maximum daily quantity of 2.2 BBtu with a maximum

46 Forecast at L56.
47 Forecast at L56.

annual quantity of 100 BBtu.[48] Lowell expects to continue purchases of small volumes of gas from Boston Gas.[49]

5. Propane

The Lowell Division has three propane-air units which are used to supplement gas supplies during period of peak use. These facilities are located at Lowell, Tewksbury and Pepperell. The capabilities of these facilities are listed in the table below:[50]

Location	(MMcf) Max. Daily Design Capacity	(MMcf) Storage Capacity
Lowell	25.0	180.0
Tewksbury	12.0	102.0
Pepperell	1.0	25.5
	38.0	307.5

Colonial did not purchase any propane for its Lowell Division for the 1982-83 heating season. Colonial, however, monitors current and projected propane supply conditions, and maintains contact with suppliers. Lowell also states that it possesses "dependable rail and over-the-road transportation" capability.[51] Thus, Lowell expects to be able to purchase spot market propane volumes necessary to meet normal and design year conditions.

6. Future Supply Sources

Lowell's Forecast indicates that an expected supply of up to 981.5 MMcf of Canadian gas from Alberta or Sable Island will be available for

48 Response to Information Request Question CGC-2, "Agreement" between Colonial and Boston Gas Company dated November 19, 1982. The Agreement also provides for a maximum hourly quantity of 4.2% of the maximum daily quantity.

49 Forecast at L55.

50 Forecast Table G-14 at L68.

51 Response to Information Request Question LD-5A.

the 1986-87 heating season.[52] Additionally, Lowell, as part of the Northeast Gas Markets Group, is exploring a potential domestic supply for the same time frame.[53] Lowell has not executed any Precedent Agreements for such supply. As indicated in the discussion of the Cape Cod Division's future supply sources, the status of imports of Canadian Gas from Alberta is uncertain. Accordingly, the Council believes it is not reasonable to rely on these volumes during the Forecast period.

7. Comparison of Resources and Requirements

a. Normal Year

The Lowell Division's supply depth and flexibility generates on an aggregate basis, a more than sufficient ability to meet its firm system requirements in a normal year scenario. Indeed, Lowell's annual available pipeline supplies of 10,732 MMcf under Rate Schedule CD-6 with Tennessee is nearly in itself sufficient on an aggregate basis to meet Lowell's normal year firm requirements. Even if Lowell's projected aggregate growth in sales does develop, Table 12 indicates that Lowell has a surplus of firm supplies over firm sendout in each of the years of the Forecast. The surpluses beginning in 1983-84 include optional quantities of LNG but do not include supplies from Boston Gas which Lowell expects to be deliverable on a best efforts basis.

In the past, Lowell's problem was not the availability of supplies, but rather the deliverability on peak days. As discussed previously, Lowell has attempted to solve this problem by negotiating a firm transportation contract for storage return gas with Tennessee. This contract has placed Lowell in a more secure position with regard to peak

52 Forecast at L55; Table G-22(B) at L-82.
53 Response to Information Request LD-3.

Table 12

Lowell Division

Comparison of Normal Year Sendout and Resources (MMcf)

	Firm Sendout	Firm Supplies[1]	Percent Surplus
1982-83	11098	12859[2]	15.9
1983-84	11324	12415	9.6
1984-85	11551	12435	7.6
1985-86	11836	12292	3.8
1986-87	12034	12422	3.2

1 Firm Supplies for each split years beginning in 1983-84 include levels of underground storage, and stored propane and LNG as indicated in Table G-22. Firm supplies also include the full AVL of pipeline supply and firm and optional quantities of LNG available form Bay State. Supplies from Boston Gas and Canadian gas are not included.

2 The figure for 1982-83 includes actual levels of storage of storage gas, propane and LNG as of April 1, 1982. See Response to Information Request LD-4. The figure also includes the firm LNG quantity of 950 MMcf under the expired contract with Bay State, and the best efforts gas available from Boston Gas.

day and heating season sendout.

b. Design Year

In a design year, Lowell has several options for increasing supplies available to meet firm requirements. Lowell can increase the quantity of optional LNG purchased from Bay State and can reduce interruptible sales.

Table 13 shows a comparison of annual firm design sendout with annual firm design supplies for the Forecast period. Table 13 indicates that Lowell has a supply cushion above its aggregate firm design requirements for each year in the Forecast period. The figures in Table 13 for firm supplies for design years beginning in 1983-84, however, include 100 MMcf of best efforts gas from Boston Gas and 120. MMcf of propane. In its Forecast, Lowell states that it expects these volumes to be available.[54] The Council does not believe this position is unreasonable. Further, the Council notes that even without these additional volumes Lowell would have a surplus above design volumes through the 1984-85 split year. Without these additional volumes, however, Lowell would not have sufficient aggregate supplies to meet its forecasted design year requirements beginning in the 1985-86 split year. The Council is inclined to believe that conservation experienced in the 1982-83 heating season may lead the company to lower its forecast of sendout requirements significantly. If that is not the case, the Council ORDERS the Company to document its plans for meeting a design year beginning in 1985-86 on. See Condition 4.

54 Forecast at L55.

Table 13

Lowell Division

Comparison of Design Year Sendout and Resources (MMcf)[1]

	Firm Sendout[2]	Firm Supplies	Percentage Surplus
1982-83	11859	13627[3]	14.9
1983-84	12097	12903[4]	6.7
1984-85	12185	12923[4]	6.0
1985-86	12642	12780[4]	1.1
1986-87	12852	12910[4]	0.5

1 Figures from Table G-22 at L73-L82.
2 Forecast Table G-5 at L67.
3 The figure for 1982-83 includes actual quantities of stored propane and LNG and actual quantities of vapor storage volumes as of April 1,1982, as indicated in Lowell's Response to Information Question LD-4. The figure also includes 500 MMcf of optional LNG available for Bay State under the November 1981 - October 1982 contract, and 100 MMcf of best efforts gas available from Boston Gas.
4 Figures include 120 MMcf of propane and 100 Mcf of gas from Boston Gas.

The design supplies shown in Table 13 for the 1986-87 split-year were derived from Lowell's comparison of resources and requirements in its Forecast indicating a purchase of LNG during the preceding year above contract quantities available from Bay State.[55] Presumably, Lowell anticipates purchase of these quantities on the spot market during non-heating season. Again, this position does not appear unreasonable. The Council, however, requests Lowell in future forecast supplements to indicate its plans with regard to purchases of LNG above contracted quantities.

Table 14 indicates Lowell's firm design year heating season resources for the years 1982-83, 1983-84, and 1986-87.

Table 14

Lowell Division

Design Year Firm Heating Season Resources[1] (Mcf)

	1982-83	1983-84	1986-87
Tennessee CD-6	5298	5298	5298
Storage	2050	2050	2050
Propane	95	192	115
LNG	1080	1080	1080
Boston Gas[2]	51	62	51
TOTAL	8574	8682	8594
Forecast Design Sendout	8283	8448	8985
Percentage Surplus	3.5%	2.8%	-4.3%

1 Forecast Tables G-22 at L73-L82.
2 Best-efforts

55 Forecast Tables G-22 at L79-L80.

For the 1986-87 heating season, Lowell also forecasted the availability of 981 MMBtu of Canadian gas. As indicated in Table 12, however, absent the volumes of Canadian gas, Lowell does not quite meet its projected design requirements for the final heating season in the Forecast period. In order to meet firm design requirements in this scenario, Lowell would require spot purchases of propane and/or LNG (298 MMcf) and a cessation of deliveries (112 MMcf) to its interruptible customers, thus providing an additional firm supply of approximately 400 MMcf.[56] Although it would not appear unreasonable at present that these additional firm volumes could be secured, the projected shortfall for the 1986-87 season is nonetheless unacceptable. Accordingly, the Council requires Lowell in its next Forecast supplement either to demonstrate the reasonableness of the availability of Canadian supplies, or to indicate alternative plans to meet future firm design heating season requirements.

c. Peak Day

Table 15 compares Lowell's aggregate peak day sendout capability with the projected peak day requirements over the Forecast period. As indicated in Table 15, Lowell possesses ample firm peak day sendout capability.

d. Cold Snap

As described earlier with regard to the Cape Cod Division, a Company's ability to meet a cold snap of prolonged daily deliveries at or near peak levels is related to its capacity for storage of LNG. As demonstrated in the Table below, the Lowell Division can meet a cold snap of approximately 26 to 27 consecutive peak days for the 1982-83 and

56 See figures in Table G-22 at L82.

Table 15

Lowell Division

Aggregate Peak Day Sendout Capability and Projected Requirements[1]
(MMcf/day)

	1982-83	1983-84	1984-85	1985-86	1986-87
Tennessee					
CD-6	35.5	35.5	35.5	35.5	35.5
SST-NE	16.0	16.0	16.0	16.0	16.0
Propane[2]	38.0	38.0	38.0	38.0	38.0
LNG[2]	79.8	79.8	79.8	79.8	79.8
	169.3	169.3	169.3	169.3	169.3
Projected Requirements[3]	105.7	107.8	110.0	112.1	114.8
Excess Capacity	63.6	61.5	59.3	57.2	54.5
As % of Requirements	60.2	57.0	53.9	51.0	47.5

1 Forecast Table G-23 at L83 with noted adjustments. Figures in Forecast reflect volumes at 1000 Btu/cubic feet.
2 Table 13 reflects maximum daily sendout capability.
3 Forecast Schedule 3 at L54, Table G-23 at L83.

1983-84 heating seasons assuming full storage quantities of LNG and propane. This figure does not include interruptible storage transportation gas which enhances Lowell's ability to meet cold snap requirements. Further, even assuming only 50 percent storage levels of propane and LNG still would provide an approximate two week cold snap supply.

Lowell Division

Cold Snap - Daily Deliveries (Mcf/day)

	1982-83 Heating Season	1983-84 Heating Season
Tennessee CD-6	35547	35547
SST-NE	16083	16083
	51630	51630
Propane	11350 (27.1 days)	11794 (26.1 days)
LNG	42709 (27.1 days)	44380 (26.1 days)
Peak Day Requirements	105689	107804

In compliance with Condition 6 in the Council's most recent decision on Lowell Gas Company, In Re Lowell Gas Company, 7 DOMSC 207, 236 (1982), the Lowell Division submitted a narrative description of a contingency plan upon cessation of major supplemental supplies. Lowell states it intends to have approximately 1000 MMcf (86.4% of storage capacity) of LNG, 100 MMcf (32.5% of storage capacity) of propane, and 2000 MMcf (100% of storage capacity) of underground storage on hand for each heating season. Lowell states these supplemental supplies are not subject to cessation and are sufficient to meet requirements of a design year. Lowell also states that in the event of a design year, interruptible sales would be discontinued and propane supplies would be replaced.[57]

Essentially, Lowell has merely restated in narrative fashion the calculations included in its comparison of resources and require-

57 Forecast at L57.

ments.[58] Lowell states "it is impossible to economically provide for every possible unforeseen cessation of major supplemental supplies."[59] Cape Cod's efforts, however, belie this assertion. Thus, the Council will reimpose this Condition in the present Decision to be met in the next Forecast supplement. The Council encourages cooperation with the Cape Cod Division in complying with this Condition.

58 See Table G-22 at L73-L82.
59 Forecast at L57.

VI DECISION AND ORDER

The Council hereby conditionally APPROVES the Second Long-Range Forecast and First Supplement of Gas Resources and Requirements of the Colonial Gas Company and ORDERS:

1. That the Company continue to monitor the 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.

2. With respect to the Lowell Division, that the Division more explicitly document its forecast of peak day requirements, particularly any data and assumptions used regarding base and heating use calculations.

3. That the Lowell Division is ordered to meet with Council staff within 60 days to discuss a method for continuing the incremental forecast improvements made in response to EFSC 80-16 Conditions 3, 4, and 5, with the intention of improving forecast reviewability and incorporating concerns pertinent to the rapidly changing natural gas market.

4. That the Company demonstrate availability of Canadian gas or indicate alternative plans to meet future firm design heating season requirements for the Lowell Division.

5. That the Company provide in its next supplement a more explicit documentation of contingency plans for the Lowell Division in the event of an unforeseen cessation of any major supplemental supplies.

James G. White, Jr.

James G. White Jr., Esq.
Hearing Officer

Dated at Boston this 31st day of March, 1983.

This DECISION was approved by unanimous vote of the Energy Facilities Siting Council at its meeting on March 28, 1983, by those representatives present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); James Brenner (for Paula Gold, Secretary of Consumer Affairs); Steven Roop (for Evelyn Murphy, Secretary of Economic Affairs); Marie Yager (for James Hoyte, Secretary of Environmental Affairs); Robert Gillette, Public Environmental Member; Dennis Brennan, Public Member Gas. Ineligible to Vote: Harit Majmudar, Ph.d., Public Member Electricity.

April 8, 1983
Date

Sharon M. Pollard

Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Algonquin SNG, Inc. for Approval of its First Supplement to the Second Long-Range Forecast	EFSC No. 82-34

FINAL DECISION

Douglas I. Greenhaus
Hearing Officer

TABLE OF CONTENTS

Introduction

Algonquin SNG, Inc. (hereinafter "the Company") is a "gas company' as defined under the regulations of the Massachusetts Energy Facilities Siting Council (hereinafter "the Council" or "the EFSC"). Rule 3.3, 980 CMR 2.03. Pursuant to the provisions of Mass. G.L. c. 164, sec. 69I and in accordance with Administrative Bulletin EFSC No. 80.2, the Company filed the First Supplement to its Second Long-Range Forecast with the Council on August 30, 1982.

Summary of the Proceedings

On November 17, 1982, the Company was ordered to post Notice of the Adjudicatory Proceeding. EFSC Rule 13.2, 980 CMR 1.03(2). No persons made requests to intervene or otherwise participate in the proceedings. A technical session was held with the Company, on December 16, 1982, at which time the Company brought to the Council's Staff responses to an initial set of requests for information and documents.

Discussion between Council's Staff and the Company resulted in a second set of discovery, the responses to which were received on January 14, 1983.

Upon review of the Company's Forecast Supplement and their responses to discovery, the Hearing Officer wrote and issued a tentative decision which was submitted for the Council's approval on the date of their March monthly meeting.

Review of the Supplement

A. Description of the Facility and Gas Production

Algonquin SNG, Inc., sits in a rather unique position within the gas supply and distribution matrix of the Commonwealth.[1] The Company owns and operates a single synthesized natural gas ("SNG") facility located in Freetown, Massachusetts. This facility manufacturers SNG from naphtha feedstock, a petroleum distillate.

In the past, the Algonquin SNG facility has demonstrated a high degree of reliability.[2] The major component of production is the naphtha feedstock. The Company assumes this feedstock "to be available in the quantity necessary to produce the contract gas quantities" which they are under obligation to supply. In support of this assumption, the Company makes reference to an adequate contract with Exxon, their naphtha supplier. Since the beginning of their relationship with the Company, Exxon has been 100% reliable in supplying Naphtha to the facility.

Naphtha deliveries are scheduled so as to allow gas production on a daily design basis during the period of November 1 through March 31. The Company is able to request a reduction of deliveries of up to fifty percent in any given month upon the giving of seasonal notice. This provision is consistent with the flexibility provisions found in the SNG-1 Rate Tariff. Naphtha arrives in 30,000 bbl shipments at a price set by Exxon.

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1 See, Appendix A.

2 Expressed as a percentage of gas produced during a season relative to contract quantity, reliability has been 100.00% over the past five years.

Naphtha storage at the facility is limited to two 266,000 bbl tanks (11,172,000 gals.). There also exists storage for 540,000 gallons of propane. Propane is occasionally injected into the SNG process to raise the heating value of the SNG gas. It may not be readily used in the facility as a feedstock. Any prospect of doing so would require the addition of massive storage facilities and substantial plant modifications with a price tag of roughly forty million dollars.

B. The SNG-1 Tariff

The Company continues, as it always has, to sell, manufacture and deliver its entire production to the Algonquin Gas Transmission Company ("Algonquin Gas") who in turn sells the SNG on a seasonal basis to help meet the winter requirements of gas distribution companies both within and without the State of Massachusetts.[3] Sales are made pursuant to long-term service agreements under Rate Schedule SNG-1 which is on file with the Federal Energy Regulatory Commission. The Company's sendout is directly correlated with the contract demands set under these agreements.

Under SNG-1, deliveries of SNG are made at the daily contract demand levels of the distribution customers during the period from November 1 through March 31 (151 days; 152 in a leap year). The daily contract demand totals 120,675 MMBtu.[4] This figure is also the Maximum Daily Design Capacity of the SNG facility.[5] The facility is able to

3 Massachusetts' purchasers of this SNG supply are as follows: Bay State Gas Company, Boston Gas Company, Colonial Gas Company, Commonwealth Gas Company, Fall River Gas Company, Town of Middleborough, and North Attleboro Gas Company.

4 Massachusett's customers account for 63,913 MMBtu or about one half of this demand.

5 See, Section III, p. 1 of the Supplement. An MMcf at 14.73 psia equals a billion Btu assuming a Btu content of 1,000 Btu per cubic foot at 14.73 psia day.

exceed this design capacity on a short-term basis, as was done in the last actual split year. However, doing so lowers plant reliability. Therefore, as might be expected, normal operation of facility equipment is at or near design points. Last year's Actual Peak Day sendout was 122,790 Mcf or 102% of design. The all-time high was 129,978 Mcf in 1975/76 or 108% of design.

For the duration of the Forecast period, years 1983-84 through 1986-87, the Company assumes full daily and seasonal contract sendout (120.675 and 18,221.925 MMcf respectively). The only variation in this forecast is a slight increase for heating season 1983-84, reflecting the leap year.

Actual sendout in the past, and conceivably in the future, need not coincide with contract demand. In reality, Rate Schedule SNG-1 allows distribution customers considerable flexibility in their actual take of the Company's SNG. Customers may request and receive more than their respective contract demands if other customers reduce their take correspondingly. Customers may reduce their contract demand provided that the net reduction of all customers allows for a minimum daily plan operating level of fifty percent of capacity. This fifty percent capacity "floor" is an operating parameter set by equipment turndown limitations and is necessary to maintain plant reliability and efficiency.

The SNG plant requires a cold start-up time of about thirty days to reach full capacity. To reach full capacity from "hot" shutdown (after a power outage) requires about twenty-four hours. Likewise, it would take about twenty-four hours to gear up from fifty percent to one hundred percent capacity.

In the past three years, distribution customers have considerably reduced their demand under the tariff's flexibility provisions. To do so, each company elects a seasonal demand and negotiates a semi-monthly delivery schedule on or before the June 20th preceeding the heating season in question. Again for split-year 1982-1983, the distribution companies have elected to reduce their respective contract demands.[6] Whether or not the distribution customers will continue to elect reductions in the future is largely a question of the relative availability and cost of alternate supply sources such as pipeline gas and/or storage service. It should be noted that if the supply situation were to change radically within a heating season, Rate Schedule SNG-1 also provides the flexibility for a distribution company to increase its take limited to the extent that other customers decide not to use their contract demand and to the extent that naphtha is available for any increase in production. In addition, a company may negotiate to obtain SNG in April up to any such amounts it chose not to receive during the heating season.

The Council recognizes the fact that the distribution customers are parties to long-term agreements with Algonquin Gas Transmission Company for the SNG-1 and that such contracts extend until October 1, 1987, continuing thereafter on a year-to-year basis.

Recent gas price data, supplied by Boston Gas and other companies in response to EFSC staff information requests, indicates that Algonquin SNG is the highest priced fuel source for Massachusetts gas companies. Whereas Algonquin's SNG is priced at more than $10 per Mcf, competing

6. See Appendix B for a company by company illustration of elected reductions.

supplemental supplies are priced 30-40% lower. As such, the Council is quite concerned that Massachusetts gas utilities minimize gas costs by purchasing only that SNG which is necessary for reliability purposes. The Company should continue to be flexible in responding to requests of distribution customers to reduce or modify their seasonal takes to minimize costs.

The Council lauds the Company for its recent attempts to provide flexibility in the contracting process and in so doing, allow the distribution customers to reduce their take of SNG-1. The Council encourages the Company to further refine these procedures to move Massachusetts gas companies, in the aggregate, as close as feasible to the 50% flow.

Conclusion

The Council finds that the Company's Supplement adequately and appropriately sets forth all necessary information and otherwise meets the requirements set out in the Council's regulations; 980 CMR 7.00 et seq.

DECISION AND ORDER

The Council hereby unconditionally APPROVES the First Supplement to the Second Long-Range Forecast of the Algonquin SNG, Inc. The Second Supplement will be due on July 1, 1983.

Energy Facilities Siting Council

Douglas I. Greenhaus

Douglas I. Greenhaus
Hearing Officer

Dated in Boston this 29 day in March, 1983.

APPENDIX A

Boston Gas Company is a wholly owned subsidiary of Eastern Gas and Fuel Associates who has an approximate one-third equity interest in Algonquin Energy who in turn owns Algonquin Gas Transmission Company and Algonquin SNG, Inc. Commonwealth Gas Company is a wholly owned subsidiary of Commonwealth Energy System who also owns an approximate one-third interest in Algonquin Energy.

The remaining share of Algonquin Energy is owned by Texas Eastern and Providence Energy Corporation.

Appendix B

	Company	Seasonal Contract Demand (MMBtu)	1982-83 Nominated Seasonal Quantity (MMBtu) (%)
1.	Bay State Gas Company	2,766,169	1,383,093 (50.0%)
2.	Boston Gas Company	1,844,012	651,524 (35.3%)
3.	Colonial Gas Company	614,721	307,362 (50.0%)
4.	Commonwealth Gas Company	3,304,031	2,711,007 (82.1%)
5.	Fall River Gas Company	1,075,724	562,855 (52.3%)
6.	Town of Middleborough	30,804	17,861 (58.0%)
7.	North Attleboro Gas Company	15,402	9,000 (58.0%)
	TOTAL	9,650,863	5,642,702 (58.5%)

This decision was unanimously approved by the Energy Facilities Siting Council at its meeting on March 28, 1983, by those members present and voting.

Voting in Favor: Ms. Marie Yeager, for the Secretary of Environmental Affairs; Mr. Steven Roop, for the Secretary of Economic and Manpower Affairs; Mr. Jim Brenner, for the Secretary of Consumer Affairs; Mr. Dennis Brennan, Public Member, Gas.

March 29, 1983
Date

Sharon M. Pollard
Sharon Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Eastern Utilities Associates System for the Approval of an Occasional Supplement to their Second Long-Range Forecast of Electricity Resources and Requirements	)	EFSC No. 83-33A

FINAL DECISION

James G. White, Jr., Esq.
Hearing Officer

On this Decision:

George Aronson
Staff Economist

The Energy Facilities Siting Council hereby unconditionally APPROVES the Petition of the Eastern Utilities Associates System for the Approval of an Occasional Supplement to their Second Long-Range Forecast of Electricity Resources and Requirements for construction of a 115-13.8 kV substation on Sykes Road in Fall River, Massachusetts.

I. INTRODUCTION AND HISTORY OF THE PROCEEDINGS

On February 17, 1983, Eastern Utilities Associates System ("EUA") filed an Occasional Supplement pursuant to Rule 65.3, 980 CMR 7.05(3), seeking Council approval of the proposed Sykes Road substation in Fall River, Massachusetts.[1] Notice of the Council's Adjudication of the Occasional Supplement was provided by publication, and by posting of the Notice and Occasional Supplement in local town halls. After appropriate Notice, a local hearing was held in Fall River on March 25, 1983, for the purpose of providing information to the public concerning the proposed substation. No petitions to intervene were received by the Council, and no member of the public attended the local hearing. On April 4, 1983, EUA submitted responses to questions submitted to EUA concerning the proposed substation.

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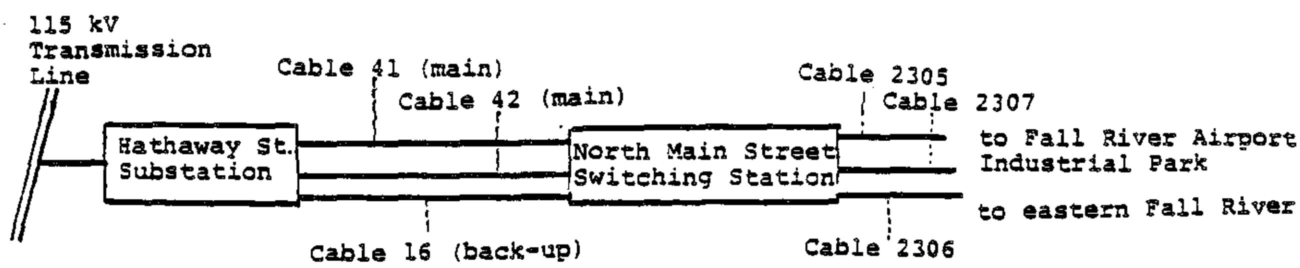
1 On January 31, 1983, the Energy Facilities Siting Council issued a Final Advisory Opinion concluding the proposed substation was subject to the Council's jurisdiction and therefore subject to the requirements of Rules 64.8(1) and (4), 980 CMR 7.04(8)(a) and (d). Eastern Utilities Associates (No. 82-33A), 8 DOMSC ____ (1983). The Eastern Utilities Associates System is described in the recent decision on its long-range forecast. Eastern Utilities Associates (No. 81-33), 8 DOMSC ___ (1982).

II. DESCRIPTION OF THE PROPOSED SUBSTATION

A. Existing Facilities

The Eastern Edison Company ("Eastern Edison"), a retail subsidiary of the EUA, provides electricity to residential, commercial, and industrial customers in the City of Fall River, including customers in the Fall River Airport Industrial Park. Electric power for the Industrial Park and adjacent areas is generated at the Somerset Power Plant, and is distributed to consumers via Montaup Electric Company's 115kV transmission line, Eastern Edison's Hathaway Street Substation ("Hathaway Street"), and North Main Street Switching Station ("North Main Street"). Transformers at Hathaway Street reduce the line voltage from 115kV to 23 kV for distribution. Three underground transmission cables run from Hathaway Street to North Main Street; cable Nos. 41 and 42, which are the main cables, and cable No. 16, which backs up the other two cables in case of an outage. Three distribution lines run from North Main Street to serve customers in the area of the proposed substation; aerial cable 2305 and spacer cable 2307, which serve the Industrial Park and adjacent areas; and spacer cable 2306, which serves the eastern part of Fall River. Figure 1 illustrates the pertinent part of the present Eastern Edison electricity distribution system in Fall River.

Figure 1. The Fall River Electricity Distribution System In the Area of the Proposed Facility



Eastern Edison currently is undertaking several long-range projects to improve the service reliability of its distribution system. In particular, the entire 23 kV system in Fall River gradually is being converted to 13.8 kV. Reasons given by EUA for the conversion include: (1) easier maintenance of lower voltage systems; (2) the need to replace aging 23 kV equipment; (3) better availability of equipment for 13.8 kV systems; and (4) fewer "clearance" problems between 13.8 kV transmission lines and adjacent structures than for lines of higher voltage. The proposed substation is an integral part of the current conversion efforts.

B. <u>The Proposed Facility</u>

The proposed facility will consist of a 115-13.8 kV transformer rated at 40 MVA with attached metal-clad switch gear. A 100-foot long tap will connect the substation directly to Montaup Electric Company's N-12 115 kV line, thereby bypassing both the Hathaway Street Substation and the North Main Street Switching Station. Four 13.8 kV distribution feeder lines from the substation will serve the northern portion of the City of Fall River, including the Industrial Park.

The site for the proposed substation is located approximately 680 feet north of Wilson Road in the South portion of the Industrial Park. The site is adjacent to the Industrial Park on the North, East, and West. On the South, the site is adjacent to the N-12 115 kV transmission line, and to the proposed Sykes Road extension. The proposed location was selected for "its proximity to the center of the northern Fall River load (particularly the Industrial Park), to the junction of the existing distribution feeders, and to the existing transmission line from the Somerset Station."[2] It is about five circuit miles closer to both the Industrial Park and to adjacent residential areas than the existing substation at Hathaway Street.[3]

The substation will be a low profile design, and will require an area of approximately 200 feet by 250 feet fronting on the proposed Sykes Road extension.[4] The proposed site is an open field in a generally flat area previously used as a construction debris fill area. The nearest property line of a residential lot is approximately 350 feet from the site on the other side of the 115 kV transmission line.

C. Cost of the Facility

Eastern Edison estimates the cost of the proposed facility at $1,360,000 in 1983 dollars,[5] based on engineering estimates of labor requirements, and the cost of equipment. Construction is scheduled for completion by December of 1983 contingent on Council approval of this Petition.

III. ANALYSIS

The Siting Council must determine that a proposed facility will provide "a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost." M.G.L.A. c. 164, sec. 69H. The Council reviews proposals for consistency with current health, environmental protection, and resource use and development policies of the Commonwealth. Rule 64.8(1), 980 CMR 7.04 (8)(a).

A. Need for the Proposed Facility

Eastern Edison justifies the need for the new substation on the

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2 Occasional Supplement at 2.
3 Occasional Supplement at 2-3.
4 Occasional Supplement at 2.
5 Response to Information Request No. 6.

consideration of providing reliable electric service to the Industrial Park and adjacent areas, as well as recent and anticipated load growth in the Industrial Park area.[6]

1. Reliability

The Eastern Edison distribution system should be designed to provide service to customers in the event of the loss of any single major component of its transmission and distribution system. This "single contingency" criterion for system reliability has been recognized by the Council as justification for the construction of electricity distribution facilities. Taunton Municipal Lighting Plant, (No. 79-51A), 8 DOMSC ____, (1982); Commonwealth Electric Company, 6 DOMSC 33,44 (1981). At present, the Eastern Edison 23 kV system serving the Industrial Park area fails to meet this reliability criterion.

The immediate reliability concern is for back-up for the three 23 kV transmission lines (cable Nos. 16, 41 and 42) that run between Hathaway Street and North Main Street. These three cables are rated at 8.2 MVA for continuous summer usage, and at 9.0 MVA for summer emergency four-hour service. The total rated capacity for all three lines is 24.6 MVA in the summer and 27.0 MVA for summer emergencies.[7] If a fault occurs on one of these transmission lines, total capacity will drop to 16.4 MVA for summer usage and 18.0 MVA for four-hour duration emergency usage. The maximum load should be kept below these limits to preserve the single contingency level of reliability in this part of the distribution system.

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6 EUA also has received a letter from the Massachusetts Department of Public Utilities stating the "necessity for this facility has been adequately demonstrated and construction should be undertaken as planned." Response to Information Request No. 1.

7 Response to Information Request, Engineers Report entitled "Fall River Airport Industrial Park Expansion and its Effect on the 23 kV Distribution System" at 2.

Eastern Edison has documented peak loads that exceed this level. In August 1981, Eastern Edison measured the total load on cable Nos. 16, 41 and 42 as 19.2 MVA. In January 1983, total load on these cables was 22.2 MVA.[8] These loads exceeded the limit necessary to preserve the single contingency level of reliability. In the event of an outage at either of these times, Eastern Edison might have been forced to lower voltages below required levels, or to cut off service to some of its customers until a maintenance crew could restore service. The operating problem is compounded by the fact that lines 2305 and 2307 are on the same poles.[9] Thus, an outage on one line might affect service on the other.

Eastern Edison has presented evidence that construction of the proposed substation will solve the reliability problem. The new substation will serve the Industrial Park and adjacent areas directly from the N-12 115 kV line, thereby avoiding usage of the transmission lines from Hathaway Street to North Main Street. Eastern Edison projects that construction of the substation will displace 5.9 MVA of customer peak load from Cable Nos. 16, 41 and 42.[10] Thus, construction of the substation will restore the single contingency level of reliability between Hathaway Street and North Main Street. It will also provide service with a single contingency reliability to the Industrial Park and adjacent areas, either through available capacity on the new 13.8 kV system, or by using Cable Nos. 16, 41 and 42 as back-up. Service reliability will be improved for the Industrial Park, for the adjacent areas served by the substation, and for the other areas of Fall River currently served

8 Response to Information Request No. 3.
9 Engineers Report, supra n. 7, at 4.
10 Response to Information Request No. 3.

by Cable Nos. 16, 41 and 42.

2. Load Growth

Eastern Edison states that the proposed substation will provide a firm supply of transformer capacity for anticipated growth in the Industrial Park. Eastern Edison bases its projection of load growth on the specific needs of businesses located in the Industrial Park. Eastern Edison has submitted a list of these businesses and a projection of their capacity needs.[11] Based on Eastern Edison's projections, the peak load on Cable Nos. 16, 41 and 42 would increase to 23.3 MVA by August of 1984.[12] Unless the proposed substation is built, load growth would increase the probability of losing the single contingency level of reliability for electricity service to the Industrial Park area during periods of peak demand.

The lack of a reliable transmission system to the Industrial Park has a negative impact on the attractiveness of the Industrial Park land to potential customers. The proposed substation would remedy this situation by providing reliable service to the Industrial Park, both at present and under future load increases.

B. Environmental Impact

The Siting Council must review the "land use impact, water resource impact, air quality impact, solid waste impact, radiation impact and noise impact" of proposed facilities. M.G.L.A. c. 164, sec. 69I.

Eastern Edison has submitted evidence that the proposed facility

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11 Response to Information Request No. 4; Engineers Report supra n. 7 at 2.

12 Response to Information Request Nos. 3, 4, 5. The Council believes that further review of Eastern Edison's load growth projections for the Industrial Park is unnecessary because the proposed facility is needed to provide reliable service.

will have no material effect on air or water quality, and will not create any solid waste or radiation.[13] Because the site is an open field, there will be no tree-cutting or use of insecticide or herbicide during preparation of the site.[14] Drainage in the area will not be affected.[15] Further, Eastern Edison has designed the proposed facility to meet requirements for environmental sound levels.[16]

To build the facility, Eastern Edison applied for and received a Determination of Non-applicability of the Wetland Protection Act from the Fall River Conservation Commission. M.G.L.A. ch. 131, sec. 40.

In addition, the Fall River Zoning Board of Appeal granted Eastern Edison's petition to construct the proposed substation on the grounds that the substation was necessary to provide electricity to the Industrial Park, and that the substation will not be detrimental to the area.[17]

In light of the evidence submitted by Eastern Edison, the Council finds that the environmental impact of the proposed facility is minimal.

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13 Occasional Supplement at 4.
14 Occasional Supplement at 4.
15 Occasional Supplement at 4.
16 Occasional Supplement at 4.
17 Response to Information Request No. 1.

C. Alternatives

Eastern Edison is required to provide, and the Siting Council is mandated to review, "a description of the alternatives to planned action." M.G.L.A. ch. 164, sec. 69I. Eastern Utilities evaluated two alternatives to the proposed substation on Sykes Road: (1) expansion of the Hathaway Street Substation and the capacity of the associated transmission lines; (2) expansion of an existing switching station along the N-12 115 kV transmission line on Bell Rock Road in northern Fall River.

1. Expansion of the Hathaway Street Substation

Eastern Edison examined the alternative of expanding the capacity of the Hathaway Street Substation and constructing new 23 kV lines from Hathaway Street to back up the existing underground lines or to carry some of the existing load.

The Industrial Park is approximately five circuit miles from Hathaway Street. The disadvantages to expansion of the Hathaway Street substation are: (1) loss of more energy in transmission and higher operating costs as compared to the construction of Sykes Road substation because of the extra distance from Hathaway Street to the load; (2) new lines would need to be built through residential neighborhoods of Fall River; (3) expansion of Hathaway Street would be inconsistant with Eastern Edison's long-range plans to convert the Fall River distribution system from 23 kV to 13.8 kV.[18]

Based on the advantages resulting from its proximity to the load, as well as compatibility with the long-range conversions efforts, the Council finds the proposed facility to be superior to expansion of the Hathaway Street substation.

18 Occasional Supplement at 3.

B. The Bell Rock Road Alternative

Eastern Edison could provide 13.8 kV service to the Industrial Park and adjacent areas by installing a transformer and related equipment at the site of Montaup Electric Company's existing 115 kV switching station at Bell Rock Road. Eastern Edison would be required either to purchase a small area at the Bell Rock Road switching station or enter into a lease arrangement with Montaup Electric. Three or four new 13.8 kV distribution lines would need to be constructed from Bell Rock Road to the Industrial Park area along Montaup Electric's existing 115 kV line right-of-way. Unlike the Hathaway Street alternative, this alternative would be compatible with Eastern Edison's long-range system conversion plans, and would not require construction through previously undisturbed residential neighborhoods.

The Bell Rock Road switching station, however, is 1.5 miles from industrial load in the Industrial Park. As was the case with the Hathaway Street alternative (or with any location that is a greater distance from the load center than the proposed facility), providing service to the Industrial Park from the Bell Rock Road alternative would result the loss of more energy in transmission than providing service from the proposed Sykes Road substation.[19] The proximity to the load center of the proposed facility as compared to the Bell Rock Road alternative also results in lower operating costs. Moreover, the four 13.8 kV lines from Bell Rock Road to the Industrial Park would all follow the same right-of-way, and would be attached to the same pole line for 1.5 miles before branching off. In contrast, the four 13.8 kV

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19 Response to Information Request No. 2

lines could leave the proposed Sykes Road substation in four different directions. Thus, the Sykes Road substation will provide better service reliability, because an outage on any one line is less likely to affect service on the other lines than an outage on a feeder line from Bell Rock Road, which might affect other lines on the same pole.

Based on its service reliability and operating cost advantages, the Council finds the proposed facility superior to the Bell Rock Road alternative.

IV DECISION

The Council is satisfied that the proposed facility is needed to provide a reliable energy supply to the Fall River Airport Industrial Park and adjacent areas in the City of Fall River. The Council finds that the proposed facility has a minimal impact on the environment, and that it is superior to the available alternatives. Therefore, the Council hereby unconditionally APPROVES the Petition of the Eastern Utilities Associates System for the Approval of an Occasional Supplement to their Second Long-Range Forecast of Electricity Resources and Requirements for construction of the proposed 115-13.8 kV substation on Sykes Road in Fall River, Massachusetts. The Council requests that EUA inform the Council upon completion of construction.

By James G. White, Jr.

James G. White, Jr.
Hearing Officer

Dated at Boston this 4th day of May, 1983.

This Decision was approved by unanimous vote of the Energy Facilities Siting Council at its meeting on May 2, 1983, by those members present and voting: Paula Gold (Secretary of Consumer Affairs); Marie Yager (for James Hoyte, Secretary of Environmental Affairs); Steven Roop (for Evelyn Murphy, Secretary of Economic Affairs); Harit Majmudar (Public Electric Member); Richard Croteau (Public Labor Member); Thomas Crowley (Public Engineering Member).

Ineligible to vote: Charles Corkin, II, (Public Oil Member)

May 5, 1983

DATE

Sharon M. Pollard

Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the First Supplement to the Second Long-Range Forecast of the Town of Wakefield Municipal Light Department	EFSC No. 82-2

FINAL DECISION

Douglas Greenhaus
Hearing Officer

On the Decision:

Juanita Haydel
Staff Analyst

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Eastern Utilities Associates System for the Approval of an Occasional Supplement to their Second Long-Range Forecast of Electricity Resources and Requirements	EFSC No. 83-33A

FINAL DECISION

James G. White, Jr., Esq.
Hearing Officer

On this Decision:

George Aronson
Staff Economist

The Energy Facilities Siting Council hereby unconditionally APPROVES the Petition of the Eastern Utilities Associates System for the Approval of an Occasional Supplement to their Second Long-Range Forecast of Electricity Resources and Requirements for construction of a 115-13.8 kV substation on Sykes Road in Fall River, Massachusetts.

I. INTRODUCTION AND HISTORY OF THE PROCEEDINGS

On February 17, 1983, Eastern Utilities Associates System ("EUA") filed an Occasional Supplement pursuant to Rule 65.3, 980 CMR 7.05(3), seeking Council approval of the proposed Sykes Road substation in Fall River, Massachusetts.[1] Notice of the Council's Adjudication of the Occasional Supplement was provided by publication, and by posting of the Notice and Occasional Supplement in local town halls. After appropriate Notice, a local hearing was held in Fall River on March 25, 1983, for the purpose of providing information to the public concerning the proposed substation. No petitions to intervene were received by the Council, and no member of the public attended the local hearing. On April 4, 1983, EUA submitted responses to questions submitted to EUA concerning the proposed substation.

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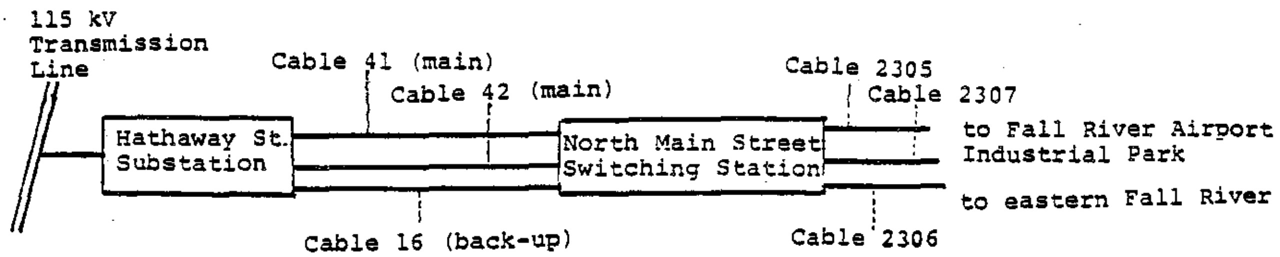
1 On January 31, 1983, the Energy Facilities Siting Council issued a Final Advisory Opinion concluding the proposed substation was subject to the Council's jurisdiction and therefore subject to the requirements of Rules 64.8(1) and (4), 980 CMR 7.04(8)(a) and (d). Eastern Utilities Associates (No. 82-33A), 8 DOMSC ____ (1983). The Eastern Utilities Associates System is described in the recent decision on its long-range forecast. Eastern Utilities Associates (No. 81-33), 8 DOMSC ___ (1982).

II. DESCRIPTION OF THE PROPOSED SUBSTATION

A. Existing Facilities

The Eastern Edison Company ("Eastern Edison"), a retail subsidiary of the EUA, provides electricity to residential, commercial, and industrial customers in the City of Fall River, including customers in the Fall River Airport Industrial Park. Electric power for the Industrial Park and adjacent areas is generated at the Somerset Power Plant, and is distributed to consumers via Montaup Electric Company's 115kV transmission line, Eastern Edison's Hathaway Street Substation ("Hathaway Street"), and North Main Street Switching Station ("North Main Street"). Transformers at Hathaway Street reduce the line voltage from 115kV to 23 kV for distribution. Three underground transmission cables run from Hathaway Street to North Main Street; cable Nos. 41 and 42, which are the main cables, and cable No. 16, which backs up the other two cables in case of an outage. Three distribution lines run from North Main Street to serve customers in the area of the proposed substation; aerial cable 2305 and spacer cable 2307, which serve the Industrial Park and adjacent areas; and spacer cable 2306, which serves the eastern part of Fall River. Figure 1 illustrates the pertinent part of the present Eastern Edison electricity distribution system in Fall River.

Figure 1. The Fall River Electricity Distribution System In the Area of the Proposed Facility



Eastern Edison currently is undertaking several long-range projects to improve the service reliability of its distribution system. In particular, the entire 23 kV system in Fall River gradually is being converted to 13.8 kV. Reasons given by EUA for the conversion include: (1) easier maintenance of lower voltage systems; (2) the need to replace aging 23 kV equipment; (3) better availability of equipment for 13.8 kV systems; and (4) fewer "clearance" problems between 13.8 kV transmission lines and adjacent structures than for lines of higher voltage. The proposed substation is an integral part of the current conversion efforts.

B. The Proposed Facility

The proposed facility will consist of a 115-13.8 kV transformer rated at 40 MVA with attached metal-clad switch gear. A 100-foot long tap will connect the substation directly to Montaup Electric Company's N-12 115 kV line, thereby bypassing both the Hathaway Street Substation and the North Main Street Switching Station. Four 13.8 kV distribution feeder lines from the substation will serve the northern portion of the City of Fall River, including the Industrial Park.

The site for the proposed substation is located approximately 680 feet north of Wilson Road in the South portion of the Industrial Park. The site is adjacent to the Industrial Park on the North, East, and West. On the South, the site is adjacent to the N-12 115 kV transmission line, and to the proposed Sykes Road extension. The proposed location was selected for "its proximity to the center of the northern Fall River load (particularly the Industrial Park), to the junction of the existing distribution feeders, and to the existing transmission line from the Somerset Station."[2] It is about five circuit miles closer to both the Industrial Park and to adjacent residential areas than the existing substation at Hathaway Street.[3]

The substation will be a low profile design, and will require an area of approximately 200 feet by 250 feet fronting on the proposed Sykes Road extension.[4] The proposed site is an open field in a generally flat area previously used as a construction debris fill area. The nearest property line of a residential lot is approximately 350 feet from the site on the other side of the 115 kV transmission line.

C. Cost of the Facility

Eastern Edison estimates the cost of the proposed facility at $1,360,000 in 1983 dollars,[5] based on engineering estimates of labor requirements, and the cost of equipment. Construction is scheduled for completion by December of 1983 contingent on Council approval of this Petition.

III. ANALYSIS

The Siting Council must determine that a proposed facility will provide "a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost." M.G.L.A. c. 164, sec. 69H. The Council reviews proposals for consistency with current health, environmental protection, and resource use and development policies of the Commonwealth. Rule 64.8(1), 980 CMR 7.04 (8)(a).

A. Need for the Proposed Facility

Eastern Edison justifies the need for the new substation on the

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2 Occasional Supplement at 2.
3 Occasional Supplement at 2-3.
4 Occasional Supplement at 2.
5 Response to Information Request No. 6.

consideration of providing reliable electric service to the Industrial Park and adjacent areas, as well as recent and anticipated load growth in the Industrial Park area.[6]

1. Reliability

The Eastern Edison distribution system should be designed to provide service to customers in the event of the loss of any single major component of its transmission and distribution system. This "single contingency" criterion for system reliability has been recognized by the Council as justification for the construction of electricity distribution facilities. Taunton Municipal Lighting Plant, (No. 79-51A), 8 DOMSC ____, (1982); Commonwealth Electric Company, 6 DOMSC 33,44 (1981). At present, the Eastern Edison 23 kV system serving the Industrial Park area fails to meet this reliability criterion.

The immediate reliability concern is for back-up for the three 23 kV transmission lines (cable Nos. 16, 41 and 42) that run between Hathaway Street and North Main Street. These three cables are rated at 8.2 MVA for continuous summer usage, and at 9.0 MVA for summer emergency four-hour service. The total rated capacity for all three lines is 24.6 MVA in the summer and 27.0 MVA for summer emergencies.[7] If a fault occurs on one of these transmission lines, total capacity will drop to 16.4 MVA for summer usage and 18.0 MVA for four-hour duration emergency usage. The maximum load should be kept below these limits to preserve the single contingency level of reliability in this part of the distribution system.

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6 EUA also has received a letter from the Massachusetts Department of Public Utilities stating the "necessity for this facility has been adequately demonstrated and construction should be undertaken as planned." Response to Information Request No. 1.

7 Response to Information Request, Engineers Report entitled "Fall River Airport Industrial Park Expansion and its Effect on the 23 kV Distribution System" at 2.

Eastern Edison has documented peak loads that exceed this level. In August 1981, Eastern Edison measured the total load on cable Nos. 16, 41 and 42 as 19.2 MVA. In January 1983, total load on these cables was 22.2 MVA.[8] These loads exceeded the limit necessary to preserve the single contingency level of reliability. In the event of an outage at either of these times, Eastern Edison might have been forced to lower voltages below required levels, or to cut off service to some of its customers until a maintenance crew could restore service. The operating problem is compounded by the fact that lines 2305 and 2307 are on the same poles.[9] Thus, an outage on one line might affect service on the other.

Eastern Edison has presented evidence that construction of the proposed substation will solve the reliability problem. The new substation will serve the Industrial Park and adjacent areas directly from the N-12 115 kV line, thereby avoiding usage of the transmission lines from Hathaway Street to North Main Street. Eastern Edison projects that construction of the substation will displace 5.9 MVA of customer peak load from Cable Nos. 16, 41 and 42.[10] Thus, construction of the substation will restore the single contingency level of reliability between Hathaway Street and North Main Street. It will also provide service with a single contingency reliability to the Industrial Park and adjacent areas, either through available capacity on the new 13.8 kV system, or by using Cable Nos. 16, 41 and 42 as back-up. Service reliability will be improved for the Industrial Park, for the adjacent areas served by the substation, and for the other areas of Fall River currently served

8 Response to Information Request No. 3.
9 Engineers Report, supra n. 7, at 4.
10 Response to Information Request No. 3.

by Cable Nos. 16, 41 and 42.

2. Load Growth

Eastern Edison states that the proposed substation will provide a firm supply of transformer capacity for anticipated growth in the Industrial Park. Eastern Edison bases its projection of load growth on the specific needs of businesses located in the Industrial Park. Eastern Edison has submitted a list of these businesses and a projection of their capacity needs.[11] Based on Eastern Edison's projections, the peak load on Cable Nos. 16, 41 and 42 would increase to 23.3 MVA by August of 1984.[12] Unless the proposed substation is built, load growth would increase the probability of losing the single contingency level of reliability for electricity service to the Industrial Park area during periods of peak demand.

The lack of a reliable transmission system to the Industrial Park has a negative impact on the attractiveness of the Industrial Park land to potential customers. The proposed substation would remedy this situation by providing reliable service to the Industrial Park, both at present and under future load increases.

B. Environmental Impact

The Siting Council must review the "land use impact, water resource impact, air quality impact, solid waste impact, radiation impact and noise impact" of proposed facilities. M.G.L.A. c. 164, sec. 69I.

Eastern Edison has submitted evidence that the proposed facility

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11 Response to Information Request No. 4; Engineers Report *supra* n. 7 at 2.

12 Response to Information Request Nos. 3, 4, 5. The Council believes that further review of Eastern Edison's load growth projections for the Industrial Park is unnecessary because the proposed facility is needed to provide reliable service.

will have no material effect on air or water quality, and will not create any solid waste or radiation.[13] Because the site is an open field, there will be no tree-cutting or use of insecticide or herbicide during preparation of the site.[14] Drainage in the area will not be affected.[15] Further, Eastern Edison has designed the proposed facility to meet requirements for environmental sound levels.[16]

To build the facility, Eastern Edison applied for and received a Determination of Non-applicability of the Wetland Protection Act from the Fall River Conservation Commission. M.G.L.A. ch. 131, sec. 40.

In addition, the Fall River Zoning Board of Appeal granted Eastern Edison's petition to construct the proposed substation on the grounds that the substation was necessary to provide electricity to the Industrial Park, and that the substation will not be detrimental to the area.[17]

In light of the evidence submitted by Eastern Edison, the Council finds that the environmental impact of the proposed facility is minimal.

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13 Occasional Supplement at 4.
14 Occasional Supplement at 4.
15 Occasional Supplement at 4.
16 Occasional Supplement at 4.
17 Response to Information Request No. 1.

C. Alternatives

Eastern Edison is required to provide, and the Siting Council is mandated to review, "a description of the alternatives to planned action." M.G.L.A. ch. 164, sec. 69I. Eastern Utilities evaluated two alternatives to the proposed substation on Sykes Road: (1) expansion of the Hathaway Street Substation and the capacity of the associated transmission lines; (2) expansion of an existing switching station along the N-12 115 kV transmission line on Bell Rock Road in northern Fall River.

1. Expansion of the Hathaway Street Substation

Eastern Edison examined the alternative of expanding the capacity of the Hathaway Street Substation and constructing new 23 kV lines from Hathaway Street to back up the existing underground lines or to carry some of the existing load.

The Industrial Park is approximately five circuit miles from Hathaway Street. The disadvantages to expansion of the Hathaway Street substation are: (1) loss of more energy in transmission and higher operating costs as compared to the construction of Sykes Road substation because of the extra distance from Hathaway Street to the load; (2) new lines would need to be built through residential neighborhoods of Fall River; (3) expansion of Hathaway Street would be inconsistant with Eastern Edison's long-range plans to convert the Fall River distribution system from 23 kV to 13.8 kV.[18]

Based on the advantages resulting from its proximity to the load, as well as compatibility with the long-range conversions efforts, the Council finds the proposed facility to be superior to expansion of the Hathaway Street substation.

18 Occasional Supplement at 3.

B. The Bell Rock Road Alternative

Eastern Edison could provide 13.8 kV service to the Industrial Park and adjacent areas by installing a transformer and related equipment at the site of Montaup Electric Company's existing 115 kV switching station at Bell Rock Road. Eastern Edison would be required either to purchase a small area at the Bell Rock Road switching station or enter into a lease arrangement with Montaup Electric. Three or four new 13.8 kV distribution lines would need to be constructed from Bell Rock Road to the Industrial Park area along Montaup Electric's existing 115 kV line right-of-way. Unlike the Hathaway Street alternative, this alternative would be compatible with Eastern Edison's long-range system conversion plans, and would not require construction through previously undisturbed residential neighborhoods.

The Bell Rock Road switching station, however, is 1.5 miles from industrial load in the Industrial Park. As was the case with the Hathaway Street alternative (or with any location that is a greater distance from the load center than the proposed facility), providing service to the Industrial Park from the Bell Rock Road alternative would result the loss of more energy in transmission than providing service from the proposed Sykes Road substation.[19] The proximity to the load center of the proposed facility as compared to the Bell Rock Road alternative also results in lower operating costs. Moreover, the four 13.8 kV lines from Bell Rock Road to the Industrial Park would all follow the same right-of-way, and would be attached to the same pole line for 1.5 miles before branching off. In contrast, the four 13.8 kV

19 Response to Information Request No. 2

lines could leave the proposed Sykes Road substation in four different directions. Thus, the Sykes Road substation will provide better service reliability, because an outage on any one line is less likely to affect service on the other lines than an outage on a feeder line from Bell Rock Road, which might affect other lines on the same pole.

Based on its service reliability and operating cost advantages, the Council finds the proposed facility superior to the Bell Rock Road alternative.

IV DECISION

The Council is satisfied that the proposed facility is needed to provide a reliable energy supply to the Fall River Airport Industrial Park and adjacent areas in the City of Fall River. The Council finds that the proposed facility has a minimal impact on the environment, and that it is superior to the available alternatives. Therefore, the Council hereby unconditionally APPROVES the Petition of the Eastern Utilities Associates System for the Approval of an Occasional Supplement to their Second Long-Range Forecast of Electricity Resources and Requirements for construction of the proposed 115-13.8 kV substation on Sykes Road in Fall River, Massachusetts. The Council requests that EUA inform the Council upon completion of construction.

By James G. White, Jr.

James G. White, Jr.
Hearing Officer

Dated at Boston this 4th day of May, 1983.

This Decision was approved by unanimous vote of the Energy Facilities Siting Council at its meeting on May 2, 1983, by those members present and voting: Paula Gold (Secretary of Consumer Affairs); Marie Yager (for James Hoyte, Secretary of Environmental Affairs); Steven Roop (for Evelyn Murphy, Secretary of Economic Affairs); Harit Majmudar (Public Electric Member); Richard Croteau (Public Labor Member); Thomas Crowley (Public Engineering Member).

Ineligible to vote: Charles Corkin, II, (Public Oil Member)

May 5, 1983
DATE

Sharon M. Pollard
Sharon M. Pollard
Chairperson

Introduction

The Town of Wakefield Municipal Light Department (hereinafter "the Department" or "Wakefield") is a "gas company" as defined under the regulations of the Massachusetts Energy Facilities Siting Council (hereinafter "the Council" or "the EFSC"). EFSC Rule 3.3, 980 CMR 2.03. Pursuant to the provisions of Mass. G.L. c. 164, sec. 69I, the Department filed the First Supplement to its Second Long-Range Forecast with the Council, on July 16, 1982.

Summary of the Proceedings

On November 24, 1982, the Department was ordered to post Notice of the Adjudicatory Proceeding. EFSC Rule 13.2, 980 CMR 1.03(2). Following the Notice period, no persons requested to intervene or otherwise participate in the proceedings. An initial set of information requests was then issued on January 31, 1983, the answers to which were received on February 20, 1983.

After oral discussions with Department's staff, a second set of information requests was issued, the responses to which were received on March 31, 1983. Following review of the Department's "Narrative" Forecast and its response to the Council's discovery, the Hearing Officer wrote and issued a Tentative Decision which was submitted to the Council for its approval.

Analysis of the Supplement

The Town of Wakefield Municipal Light Department is a fairly small gas system consisting of 4700 customers, 97% of which are residential. The Department exists as an all requirements customer of the Boston Gas Company, which supplies gas through four take-points located in the town of Wakefield. These take-points are physically adequate for the purpose of supplying gas of sufficient pressure, even during periods of extreme demand.

At present, the Department has no jurisdictional facilities of its own nor does it plan to build or otherwise obtain any such facilities. As in the past, the Department has filed with the Council a simple "Narrative" forecast which is aimed at supplementing Boston Gas's filing. See, EFSC No. 79-2. This analysis of the Department's Forecast Supplement shall focus on the four basic concerns raised in the last Wakefield Decision. See, EFSC No. 81-2.

a. The Boston Gas Contract

Wakefield is under contract with the Boston Gas Company for a firm supply of gas over the entire forecast period. The contract extends until August 31, 1990, "with a possible reopener for a rate change on or after August 31, 1985." See 1982 Forecast, p. 1.

Under the contract, Wakefield is allowed to increase their annual purchases from Boston Gas by five percent over actual purchases made in the preceding twelve months. In addition, Wakefield's supply is subject to curtailment in the event that Boston Gas must curtail supplies to its retail customers. Lastly, Wakefield is subject to a clause prohibiting new hookups in the event that Boston Gas itself invokes a moratorium on new hookups.

At present, neither of these two restrictive clauses are in effect. As recently as the last forecast period, Wakefield had been operating under a new hookup prohibition. When this prohibition was lifted, a significant number of conversions were allowed to go forward and as a result the contract amount was exceeded in 1981/82. For 1982/83, one hundred new customer were forecasted for addition to the system. Of these, 80% will be existing customers converting to gas heat. The Department again forecasts that the contract amount will be exceeded.

Under the contract, if the Department exceeds its annual contract amount, it may be subject to the payment of a penalty based on the contract's "unauthorized overrun" clause. For the years 1980/81 and 1981/82 in which the Department did take gas in excess if its contract limit, Boston Gas did not treat the overrun as "unauthorized" under the contract and not penalty was assessed.

b. Comments on Boston Gas Forecast

The Department is required to and has commented on the accuracy and adequacy of Boston Gas's sendout figures.[1] The Department believes that Boston Gas has slightly overestimated the amount of gas that Wakefield will require in future years. This overestimation is due to the fact that the Department believes that its new load will be primarily in the form of conversion customers and not new customers as Boston Gas suggests.

The Council is satisfied that this difference is not significant and that in any event Boston Gas' supply will be sufficient to meet the Department's needs. In the future, the Department should continue to comment on the Boston Gas filing if Boston Gas presents an inaccurate or inadequate picture of the gas supply necessary to meet Wakefield's needs.

c. Conservation

The Department continues to provide the Council with estimates of the effect of conservation on their system. The Department participates

1 The 1982 Boston Gas filing was approved in November, 1982. EFSC No. 82-25.

in a Residential Conservation Service in conjunction with Mass SAVE, Inc. They also periodically send out bill stuffers aimed at educationing consumers on how to conserve energy.

Increased conservation in both residential classes (heating and non-heating) has been recognized. A system-wide conservation figure of 3% for 1981-1982 was noted, up from 2% in 1980-81. The Department expects this 3% per annum trend to continue in the future, largely as a consequence of increasing gas costs. The Company has not taken this conservation figure into account in its forecast of system growth. It should do so in all future forecasts.

The Council appreciates the Department's attempts to provide reasonably accurate conservation figures and, subject to the above condition, urges this practice in future forecasts.

d. Design Year and Peak Day

Design Year

The Department no longer equates peak day and design year requirements with its contractual limitations. This past practice was criticized by the Council in EFSC 81-2. The Council recognizes and appreciates the Department's efforts to improve their peak day and design year planning.

The Department determines monthly design requirements for each customer class by first calculating actual base use in 1981/82. The average monthly sendout for June, July and August for each customer class is assumed to be monthly base use. This is subtracted for total monthly sendout for each customer class to arrive at the heat sensitive portion of total sendout. This heat sensitive load is divided by the actual number of degree days for the month to arrive at a heating figure by customer class (mcf/degree day). This heating factor is then adjusted to reflect expected usage in a design year and added to monthly base use to total monthly design requirements. The Department uses as its design year criteria the coldest split year in the past thirty, for a design year degree day figure of 6313.

The Council requires as a condition for approval of this forecast that the Department provide a similar design year figure for each of the five forecast years. Such design year figures should of course reflect forecasted conservation and/or load growth and are essential to an accurate forecast.

The Council believes that the Department has taken appropriate steps to come up with a reasonable design year figure reflecting the temperature sensitive nature of each customer class. It urges the Department to continue to update this design year figure annually as the actual customer use factors, upon which the Department bases its calculations, continue to change.

The Department notes[2] that if a design year should occur, then the only foreseeable supply contract constraint would be the extent to which Boston Gas is able to achieve its own necessary supply. Boston Gas's supply forecast was approved in November, 1982. EFSC 82-25.

Peak Day

The Department states in response to question 4 of the Council's Second Set of Information Requests that "we are unable to calculate our peak day sendout because there are no instruments recording the daily sendouts". At present, daily meter readouts are made at only two of the four take points and only on Monday through Friday of each week.

2 1982 Forecast, p. 2.

The Council notes the Department's plans to install a SCADA (Supervisory Control and Data Acquiring) system within the next two to three years. This system will provide, among other things, the data needed to calculate an accurate peak day. The Council urges the Department to keep us informed as to the progress it is making towards acquiring the SCADA system.

The Council cannot overemphasize the importance of making a forecast of peak day use. It is necessary part of any reasonable, reviewable and accurate forecast. Approval of the Forecast Supplement is therefore conditioned on the Department making such a forecast in all future filings.

The Council suggests that the Company use daily base use estimates and heating use per degree day factors for each customer class, derived from design year calculations, and an appropriate degree day criteria to estimate peak day requirements.

The Council is willing to assist the Department in any way it can in order that a peak day figure be obtained.

Decision and Order

The Council hereby APPROVES, subject to the foregoing comments and Conditions, the First Supplement to the Second Long-Range Forecast of the Town of Wakefield Municipal Light Department. The Second Supplement will be due on September 1, 1983.

Energy Facilities Siting Council

Douglas Greenhaus

Douglas I. Greenhaus
Hearing Officer

Dated in Boston this 21st day of June, 1983.

This decision was unanimously approved by the Energy Facilities Siting Council at its meeting on June 20, 1983, by the members present and voting.

Voting in Favor: Ms. Sharon M. Pollard, Chairperson, Secretary of Energy Resources; Ms. Marie Yager, for the Secretary of Environmental Affairs; Mr. Stephen Roop, for the Secretary of Economic and Manpower Affairs; Mr. Dennis J. Brennan, Public Member, Gas; Mr. Richard A. Croteau, Public Member, Labor; Mr. Thomas J. Crowley, Public Member, Engineering; and Mr. Robert W. Gillette, Public Member, Environment.

June 22, 1983

DATE

Sharon M. Pollard

Ms. SHARON M. POLLARD
CHAIRPERSON

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the 1982 Long-Range Gas Forecast Supplement of the Holyoke Gas and Electric Department	)	EFSC No. 82-23

FINAL DECISION

Douglas I. Greenhaus, Esq.
Hearing Officer

On the Decision:

Juanita Haydel
Staff Analyst

Introduction

The Holyoke Gas and Electric Department (hereinafter "the Department" or "Holyoke") is a "gas company" as defined under the regulations of the Massachusetts Energy Facilities Siting Council (hereinafter "the Council" or "the EFSC"). EFSC Rule 3.3, 980 CMR 2.03. Pursuant to the provisions of Mass. G.L. c. 164, sec. 69I, the Department filed its 1982 Gas Forecast Supplement with the Council, on December 15, 1982.

Summary of the Proceedings

On January 20, 1983, the Department was ordered to post Notice of Adjudicatory Proceeding. EFSC Rule 13.2, 980 CMR 1.03(2). Following the Notice period, no persons requested to intervene or otherwise participate in the proceedings. A set of Information Requests was issued on April 7, 1983, the answers to which were received on May 6, 1983. Following review of the Department's Forecast and its response to the Council's discovery, the Hearing Officer wrote and issued a Tentative Decision which was submitted to the Council for its approval.

Analysis of the Forecast

A. Design Methodology

In the last Siting Council Decision on a Holyoke Gas Forecast, EFSC No. 81-23, the Council specifically set out four Conditions which the Department was to address in EFSC No. 82-23. The first Condition required Holyoke to "...change its design year methodology to reflect the coldest historical split year actually experienced in a given time period..." This has been done.

In the past, the Department had selected the coldest heating season and the coldest non-heating season experienced over the past twenty-six years and combined the two to come up with an overly conservative 7,322 degree day figure. The new methodology involves surveying the past twenty-seven years for the coldest single historical split year. Using this methodology Holyoke has derived a design year total of 6,985 degree days (April 1969-March 31, 1970).

The Department has also improved its method of calculating design day by using the coldest day ever experienced by the system or 68 degree days (December 25, 1980). In past forecasts, the Department derived a design degree day by taking a weighted average of the number of daily degree days above 60 for the past twenty-five years. Holyoke's design degree day and design year criteria currently allow the Department to provide for the coldest conditions most likely to occur. They are therefore appropriate and reliable criteria for planning purposes.

B. Forecast of Sendout Requirements

The Department determines its forecast requirements by first calculating monthly base load on a class basis using actual 1981-82 split-year data. The Department then calculates base use per customer and heating load per customer per degree day (MCF/Customer/DD). It next compares this data for 1981-82 with that of 1980-81 to determine any increase (or decrease) in base use per customer and MCF/Customer/DD. The increase in MCF/Customer/DD is then correlated with the addition of 200 new customers. This correlation provides the Department with an estimate of the expected increase in MCF/Customer/DD for each new customer added. Lastly the Department adjusts these usage figures to reflect expected gas usage under normal and design conditions.

As an example, the Department found a heating increment increase of .0005 MCF/Customer/DD by comparing 1980-81 heat use with that of 1981-82. Without further explanation, the Department attributes this .0005 MCF/Customer/DD increase to the addition of 200 new residential customers. The above methodology was repeated for forecasted base use and forecasts of industrial and commercial requirements. In general, the Council finds this to be an appropriate, reviewable and reliable methodology for a gas company the size of Holyoke.

The Council appreciates the Departments attempts at determining the cause of increased (or decreased) customer usage but, as a condition for approval of its Forecast, we must ask that the Department take its analysis one step further. First, the Department must provide the Council with explanations of why the noted increase (or decrease) cannot be attributed to other plausible factors such as the likelihood that all residential customers have increased their usage on the average or the possibility that 1980-81 customer figures, not being based on accurate computer data, were themselves inaccurate. Second, if the Department is confident that increased base usage is due to the addition of new residential customers, the Department should explain, based on its best judgement, why it is that an additional residential customer uses more gas than an existing customer. Lastly, the Department should supply a similar explanation of changes in usage for its other customer classes.

C. Conservation

For the duration of the forecast period the Department does not expect to convert any residential non-heating customers to residential with gas heat. Additional forecasted heating customers (25/year) will be new customers. Siting Council Order No. 81-23 requested that the Department develop a forecast of residential conservation that accounts for the "price of gas, both in terms of annual percentage increases, as regards predicted conservation by established residential gas heating customers, and in comparison to other residential space heating fuels..." The Department has made estimates of oil, gas, and electric fuel costs for the forecast period by increasing each 7 percent annually based on current inflationary trends and a judgment that the inflation rate would continue to increase at approximately 7% per year. (See, Info. Request No. 1). This method results in a forecast of the price of gas just slightly below that of oil for each of the forecast years. On that basis, the Department believes that new customers will choose between gas and oil heat largely because of preference as they believe that natural gas prices have hit the "market clearing price". (See, 1982 Forecast, Section II, 2a).

The Council wishes to commend the Department for its attempts at predicting fuel prices and the effects that these prices will have on customer growth. The Council notes, however, that certain recent events, such as the lowering of the world price of oil, may tend to affect the relative prices of home heating fuels. In addition, the Council urges the Department to keep abreast of future events such as modifications in the gas decontrol scheme and how such possible modifications will influence customer load growth and/or changes in customer usage.

The Department asserts that their customer's conservation efforts have leveled off and that "volumes of gas that will become available to the Department through conservation over the forecast years will be small". (See, 1982 Forecast, Section II, 2a) The Department reaches these conclusions after reviewing their 1981-82 actual usage figures.

D. Peak Day Sendout

Peak day sendout was calculated by the Department on a class by class basis. Heating components were developed by using MCF/DD/Customer use figures and multiplying these figures by design degree days and by the number of customers in the particular class. Base use components were multiplied by the number of customers in the class and divided by 30 for a daily use figure. Base and heating components were added and the peak day sendout for each class summed to provide a sub-total peak day sendout.

The sub-total figure was then adjusted for unaccounted for gas. The Department forecasts a peak day sendout of 14,260 MCF in 1982-83 up to 14,789 MCF in 1986-87.

E. Accurate Data

Since their 1981 filing, the Department has been able to appreciably improve their computer capability. This is certainly a step for which the Department should be commended. The data upon which the Department bases its forecast will now be more accurate and complete. As of the present, the Department is better able to obtain accurate counts of its heating and non-heating customers. Previously the Department had based its forecast on the results of a seven-year old customer survey. This method was found by the Council to be inappropriate and the Council conditioned its 1981 approval on the

Department obtaining computerized data. The Council is satisfied that this Condition has been met.

F. Supply Narrative

In the Siting Council Order No. 81-23 the Department was asked to continue their practice of detailing its supplemental supply sources. In particular, the Council's decision provided that the 1982 filing should at a minimum: (1) detail the status and/or results of the Department's contract negotiations with Bay State; (2) update the usage history of the Bay State interconnections to include the flows experienced during the winter of 1981-82; (3) describe Holyoke's LNG purchase experiences during the 1981-82 winter; and (4) describe Holyoke's propane purchase experiences during the 1981-82 winter.

The Department has substantially complied with all of the above conditions. Holyoke presently has a contract to purchase LNG from Bay State. The contract extends until March 31, 1988. Under this contract, Holyoke receives 75% of its purchases as pipeline displaced gas through two interconnections with Bay State; the remaining contract amounts are received by truck. This trucked LNG is stored at the Department's LNG Satellite which has a 220,000 gallon capacity. Under the contract, Holyoke takes 20,000 MCF firm in the summer, 157,500 firm in the winter and, in addition, holds an option for 52,000 MCF in the months of December, January and February. On August 23, 1981, the contract was amended so as to allow for a right of first refusal on additional gas options in the event that Bay State makes such volumes of gas available to any other of its off-system customers. The contract amendment also requires Holyoke to use its best effort to receive Bay State gas through the pipeline displacement method of delivery.

The LNG storage satellite sent out a total of 40 MMCF in 1981-1982 and had a maximum 24 hour sendout of 1 MMCF that same year (this compares to a daily design capacity of 12 MMCF). Under the contract, deliveries through the interconnections can be as great as 175 MCF per hour or 4200 MCF per day. During the 1981-82 winter, Holyoke purchased from Bay State 184,581 MCF through the interconnections and an additional 18,286 MCF by truck.

In addition to the LNG purchased from Bay State, Holyoke contracted with three propane suppliers for supplies necessary to insure that an inventory of 40% of storage capacity was maintained. Holyoke has a total propane storage capacity of 201,000 gals. Total propane contract amounts equal 27,000 MCF firm and 81,000 MCF optional. For the winter of 1981-82, Holyoke purchased 414,000 gallons of propane (about 46 MMCF).

The Council is satisfied with the Department's narrative description of its supplemental supply sources. Such narratives work well to ellucidate the supply tables. Similar descriptions should be included in future forecasts and supplements with particular attention being paid to changes in the Department's supplemental supply mix.

In total, the Department has again put together a supply forecast which meets the Council's "appropriate, reviewable and reliable" standard. It estimates an available supply of 15.4 MMCF to meet peak day sendout requirements in each year of the forecast period. Again, the maximum peak day requirement forecasted by the Department is 14.8 MMCF in 1986-87.

Decision and Order

The Council, subject to the foregoing comments and Conditions, hereby APPROVES the 1982 Long-Range Gas Forecast Supplement of the Holyoke Gas and Electric Department. The next supplement will be due on September 1, 1983.

Energy Facilities Siting Council

by: Douglas Greenhaus
Douglas I. Greenhaus, Esq.
Hearing Officer

Dated in Boston this 21st day of June, 1983.

This decision was unanimously approved by the Energy Facilities Siting Council at its meeting on June 20, 1983, by the members present and voting.

Voting in Favor: Ms. Sharon M. Pollard, Chairperson, Secretary of Energy Resources; Ms. Marie Yager, for the Secretary of Environmental Affairs; Mr. Stephen Roop, for the Secretary of Economic and Manpower Affairs; Mr. Dennis J. Brennan, Public Member, Gas; Mr. Richard A. Croteau, Public Member, Labor; Mr. Thomas J. Crowley, Public Member, Engineering; and Mr. Robert W. Gillette, Public Member, Environment.

June 22, 1983
DATE

Sharon M. Pollard
Ms. SHARON M. POLLARD
CHAIRPERSON

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of Gosnold Municipal Electric Company's Long-Range Forecast of Electric Power Needs

EFSC No. 82-57

FINAL DECISION

Douglas I. Greenhaus
Hearing Officer

Introduction

The Gosnold Municipal Electric Company (hereinafter "the Company" or "Gosnold") is an "electric company" as defined under the regulations of the Massachusetts Energy Facilities Siting Council (hereinafter "the Council" or the "EFSC"). EFSC Rule 3.3, 980 CMR 2.03. Pursuant to the provisions of Mass. G.L. c. 164, sec. 69I, the Department filed with the Council information describing the electric power needs and requirements of its market area on May 16, 1983.

Summary of the Proceedings

Gosnold is the smallest electric utility regulated by the Siting Council. The Town of Gosnold is actually a chain of five islands, four of which are privately owned. The utility is located on the remaining island of Cuttyhunk. There are approximately 35-40 year round residents in the utility's service area. The number of residents increases to about 400 in the summer. Summer peaks occur during boating regattas which are annually hosted by Cuttyhunk.

This decision reviews the first filing made by Gosnold with the Council. That no prior filing was made is in part due to a disagreement between the Company and the Council's Staff on whether or not the Council had the jurisdiction to require a filing from the utility. Council's Staff made the determination that it had the requisite jurisdiction on October 14, 1981. After that time Council's Staff met with the Company on an informal basis to discuss which specific information would be necessary for EFSC purposes.

It was agreed that the Company be given special consideration. On March 31, 1982, a Subpeona Duces Tecum issued to the Company requesting a minimal amount of information. The Company was again asked, in a letter dated April 12, 1983, to file this information in the form of a simple two-page narrative. Gosnold complied with this request on May 16, 1983. The Council asks that the Company file a similar forecast each year, updating its answers where appropriate.

Analysis of the Forecast

The Company has supplied the Council with total yearly consumption figures for the years 1978 through 1982. Yearly consumption has averaged about 333,000 kwh for the system.

Presently Gosnold has four diesel generators on line with a total rating of 380 kW. Diesel fuel is barged in from New Bedford. The Company has a summer peak of approximately 150 kW and a winter peak of approximately 45 kW. Therefore Company's generation capacity far exceeds its peak demand.

The Company states that it is presently able to meet peak demand levels and that it has the capacity to meet forecasted peak well into the future since few if any new additions to the system are expected. In addition, there exist no reasons to believe that consumption by present customers will increase in the future. Consequently, there are no present plans to add capacity or to expand facilities.

Decision and Order

The Council hereby APPROVES, without condition, the Gosnold Municipal Electric Company's 1982 Forecast of Electric Power Needs and the 1983 Supplement. The First Supplement will be due on May 1, 1984.

Energy Facilities Siting Council

Douglas Greenhaus

Douglas I. Greenhaus
Hearing Officer

Dated in Boston this 21st day of June, 1983.

This decision was unanimously approved by the Energy Facilities Siting Council at its meeting on June 20, 1983, by the members present and voting.

Voting in Favor: Ms. Sharon M. Pollard, Chairperson, Secretary of Energy Resources; Ms. Marie Yager, for the Secretary of Environmental Affairs; Mr. Stephen Roop, for the Secretary of Economic and Manpower Affairs; Mr. Richard A. Croteau, Public Member, Labor; Mr. Thomas J. Crowley, Public Member, Engineering; and Mr. Robert W. Gillette, Public Member, Environment.

June 22, 1983
DATE

Sharon M. Pollard
Ms. SHARON M. POLLARD
CHAIRPERSON

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Chester Municipal Electric Light Department for Approval of the Second Long-Range Forecast of Electricity Requirements and Resources	EFSC Docket No. 81-30

FINAL DECISION

The Energy Facilities Siting Council ("Council") hereby approves conditionally the Second Long-Range Forecast of the electricity resources and requirements of the Chester Municipal Electric Light Department ("Chester").

I Procedural History

Chester filed its Second Long-Range Forecast on October 5, 1981.[1] On October 13, 1981, the Hearing Officer sent a letter to Chester regarding certain perceived deficiencies in the filing of October 5, 1981.[2] The Council's files do not contain any response by Chester[3], or any additional communication between Chester and the Council's Staff

1 The Second Long-Range Forecast consisted of Energy Facilities Siting Council ("Council") Table Nos. E-1, E-2, and E-8. This Forecast did not contain any narrative description of changes in the resources or requirements of the Chester Electric Municipal Light Department ("Chester").

2 In particular, the Tables originally submitted by Chester in this Docket appeared to be identical to those submitted in the most recently approved Forecast Supplement in Docket No. 80-30. Chester Mun. Light Dept., 6 DOMSC 152 (1981). The actual data for 1980 in the present Docket were the same as the projected data for 1980 in Docket No. 80-30, in each Table. Additionally, projected data for 1990, the tenth year of the Forecast period, were not originally included in the Tables in the current Docket.

3 The Council's file in this Docket indicates that Chester filed revised Tables on October 28, 1981. The revisions, however, are absent from the file, and Chester was unable to provide a copy of such revisions.

regarding the filing of October 5, 1981.

In February 1983, the new Hearing Officer contacted Chester concerning the Council's review of Chester's Forecast.[4] Instead of updating the previously-submitted Tables, Chester filed with the Council on March 22, 1983, a set of charts prepared in the fall of 1982 by Chester in concert with Western Massachusetts Electric Company's ("WMECO") manager of Energy Management Services in Pittsfield, Massachusetts. In response, by letter dated March 24, 1983, the Hearing Officer informed Chester that the charts contained most of the necessary information for review of Chester's Forecast.[5] The Hearing Officer, however, requested Chester to provide certain additional data and a narrative description of changes in Chester's service area characteristics in the last few years. On June 6, 1983, the Hearing Officer sent Chester a letter indicating plans to attend the June 15, 1983, meeting of the Chester Light Commission and outlining specific topics for discussion.[6] On June 15, 1983,

4 In the period between October 1981 and February 1983, Chester's manager departed and was replaced. In addition, the composition of the three person Chester Light Commission had changed.

5 The charts submitted by Chester included three Tables:
Table No. 1 includes actual data for 1982, and projected yearly data for the years 1983-2007. Table No. 1 contains data on residential sales; industrial sales; streetlighting sales; total sales; losses and unaccounted for use; energy purchased from Northeast Utilities Service Company ("NUSCo"); and system summer and winter peak daily purchases.
Table No. 2 includes actual data for July-December, 1981, and projected data for 1983-1984 on a monthly basis. Table No. 2 contains data on total monthly sales; losses and unaccounted for use; monthly energy requirements; energy purchased from NUSCo, and summer and winter daily peak purchases from NUSCo.
Table No. 3 includes data on "seasonal forecast of generation and entitlements." Essentially, this Table provides data on actual and projected winter and summer peaks for the years 1981-2007.

6 Specifically, the Hearing Officer requested data for the number of customers in various classes and the historic and projected consumption of municipal buildings. Questions were posed regarding the data already provided on the charts.

the Hearing Officer attended the meeting of the Chester Light Commission. The Commissioners were very cooperative and provided the requested information.

II REVIEW STANDARD

A) Conditions Imposed in Last Decision

The Council imposed three conditions in its last decision concerning Chester. Chester Municipal Electric Light Department, 6 DOMSC 152, 154 (1981). Chester has met the first condition, namely submission of a typed forecast, and partially has met the last two conditions. Chester has submitted projected peak load data for the years of the forecast period and beyond. Chester, however, has not supplied peak load data for the historical period beginning in 1970. (Condition Three to last decision). Similarly, Chester has not submitted a complete set of historical data. (Condition Two to last decision).

The Council is aware that compilation of the requested historical information may be difficult. Nevertheless, given the importance of accurate historical data to the planning efforts of WMECO as part of the Northeast Utilities System, the Council will request that Chester continue efforts toward compilation of a complete set of historical data.

B) Standard for Small Utilities

The Council applies a three-pronged standard on a case-by-case basis to determine whether a forecast is reasonable. A forecast must be (1) appropriate or technically suitable for the size of the utility; (2) reviewable in the sense that results can be duplicated and evaluated by another person with the same information; and (3) reliable in that the assumptions, judgements and data utilized lead to a forecast with a high probability of occurrence. See Nantucket Electric Company, 8 DOMSC 257, 260 (1982).

The Council also has recognized that small all-requirements utilities occupy a special position in regard to economic forecasting. In particular, the power requirements of these utilities are small in comparison to those of their wholesale suppliers. Secondly, the large suppliers include forecasts of "sales for resale" to small utilities in their own annual filings with the Siting Council.[7] Thus, for a system like Chester, accurate historical data, which can be utilized for forecasting purposes by the large supplier, may be more important than precise projection methods. Chester, supra, 6 DOMSC at 154.

Given the foregoing considerations, the Council finds that Chester's Second Long-Range Forecast, as updated, is appropriate, reviewable, and reliable. Specifically, the Council commends the cooperative effort of Chester and WMECO in completing the charts submitted in this Docket. Such efforts satisfy the Council's stated goal of providing the larger suppliers with reliable historical data for use in forecasting.[8]

III Analysis

Chester serves approximately 400 residential customers and a handful of industrial and municipal customers.[9] Most of Chester's

7 See generally, Brown, J.P., Review of Small Electric Co. Demand Forecasting (EFSC Research Paper, April 14, 1981). The Northeast Utilities System considers Chester's estimates of energy purchases and peak loads in its most recently-filed Supplement. Northeast Utilities System, (Docket No. 83-17) (Annual Supplement at 14).

8 For future filings, the Council will accept the charts supplied in this Docket instead of the Council Tables normally filed by utilities. These charts, however, should be supplemented with: (1) narrative descriptions of changes since the last filing, and (2) any specific information requested by the Council.

9 Effective July 1, 1983, Chester has instituted with the Department of Public Utilities two new commercial rate schedules.

residential customers do not utilize electric heat. Chester is served by WMECO under an all-requirements wholesale power agreement. The agreement specifies no limits on the amount of power which can be purchased by Chester.

Chester relies on historical data and knowledge of impending changes in its service territory in making its projections. Chester projects a nearly constant compound growth in total sales, residential sales and industrial sales during the forecast period. The projected growth in residential sales of approximately 30 to 35 MWH per year over the forecast period represents a compound annual growth rate of just under one percent. Similarly, Chester projects nearly constant compound growth rates for industrial sales (0.4%) and total sales (0.75%) over the forecast period.

The foregoing projections are based on several factors. First, Chester projects no major housing construction in the foreseeable future. Chester considers construction of three new residential units per year as the maximum for purposes of the Forecast. Although a number of lots have been sold in Chester, including twenty-seven so far in 1983, no building permits have been issued. The projected one percent residential growth rate takes these factors into account. The federal government is investigating possible plans for construction of a senior citizens' center in Chester. At the present time, however, the prognosis of these plans is uncertain. Chester considers these plans to be too speculative to be reflected in the Forecast. Chester's projections reflect a "slight conservation effect" based on the rising cost of electricity, and heavy reliance on wood burning as a winter heat source. Again, the conservation effect was considered by Chester in projecting the one percent residential growth rate.

The residential use growth rate projected by Chester is in line with the compound annual growth rate of one percent projected between 1983 and 1992 by the Northeast Utilities System ("Northeast Utilities").[10] The industrial growth rate projected by Chester, however, is below the 2.3 percent compound annual growth rate projected by Northeast Utilities.[11] This difference is explained by the fact that Chester has few industrial customers, one of which ceased operations during 1982. This single industrial customer purchased approximately 890 Mwh of electricity during a 1981-1982 split-year. This customer still is connected to Chester's system, and Chester projects that operations will resume by 1985. Chester's system peak load projections for 1983 and 1984 reflect the temporary loss of this industrial customer. Chester does not project, however, a drop in industrial sales for the years 1983 and 1984. Instead, Chester has applied the same growth factor for these years. The Council finds the projected overall industrial growth rate for the forecast period to be reasonable. The projections for 1983 and 1984, however, should be corrected to reflect Chester's temporary loss of its biggest industrial customer.

In regard to average consumption by residential customers, Chester's Forecast is problematic. Prior to July 1, 1983, Chester maintained a separate rate schedule for "total electric service" for residential customers with electric heat. Effective on July 1, 1983, however, Chester instituted a new residential service rate schedule covering all residential uses. Thus, the exact number of residential

10 Northeast Utilities System, Docket No. 83-17 (Annual Supplement at iii).

11 Northeast Utilities System, Docket No. 83-17 (Annual Supplement at iii).

customers with heat cannot be readily ascertained.[12]

Secondly, the number of residential customer without electric heat varies widely by year as reflected in Chester's annual Municipal Light Plant reports filed with the Department of Public Utilities for 1978 through 1982.[13] The change in numbers, however, is not reflected directly by commensurate changes in overall residential sales. Thus, the average consumption per residential customer without heat fluctuated between 4122 and 8103 Kwh between 1979 and 1982. For planning purposes, Northeast Utilities should be aware of the exact historical number of residential customers. Accordingly, the Council requests that Chester, in its next Forecast Supplement, provide the exact number of residential customers for the years 1974-1983 and reasons, in narrative fashion, for any substantial year to year changes in those numbers.

In regard to alternative sources of supply, it should be noted that three customers in Chester have windmills, none of which provides sufficient energy to meet the customer's total electricity needs. Chester also owns rights to two take-offs from the Knightville Dam in nearby Huntington, Massachusetts. Presently, however, Chester believes the projected costs associated with transmission of power to Chester outweigh benefits to Chester from possible installation of hydroelectric facilities at the site.

In conclusion, Chester's principal efforts should be directed to the compilation of accurate historical data and toward communication

12 According to the Annual Municipal Light Plant Reports filed by Chester with the Department of Public Utilities ("DPU") between 1978 and 1981, the number of heating customers varied between 39 and 41.

13 For example, Chester's annual Municipal Light Plant Report with the DPU for the year ending 1982 reflects a drop of 68 customers from 1981, which in turn was a drop of 74 customers from 1980.

with WMECO regarding Chester's electricity requirements. The Council Staff is available to answer questions at any time.

IV Order

The Council APPROVES Chester's Second Long-Range Forecast (as updated) subject to the following conditions:

1. That in its next filing, Chester submit accurate historical data for the period 1974-1983 in the following categories: number of residential customers (with and without heat) and average use per residential customer (Tables E-1 and E-2); and peak load data (Table E-11).

2. That Chester submit its next filing on April 1, 1984. The filing shall consist of either (a) the information contained in the charts compiled in cooperation with WMECO, or (b) Council Form TR-2 (Data for Annual Supplement for Total Requirements Customers). In either instance, Chester will provide a narrative description of any projected changes in the Second Long-Range Forecast approved herein.

Energy Facilities Siting Council

James G. White, Jr.

James G. White, Jr., Esq.
Hearing Officer

This Decision was approved by unanimous vote of the Energy Facilities Siting Council on August 8, 1983, by those members and designees present and voting: Chairperson Sharon M. Pollard; Sarah Wald (for Secretary Paula W. Gold); Marie Yager (for Secretary James S. Hoyte); Harit Majmudar (Public Electricity Member); Robert Gillette (Public Environmental Member).

August 12, 1983
Date

Sharon M. Pollard

Sharon M. Pollard,
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Russell Municipal Light Department for Approval of the Combined Second Long-Range Forecast with First and Second Supplements of Electricity Requirements and Resources	EFSC Docket No. 81-31

FINAL DECISION

The Energy Facilities Siting Council ("Council") hereby approves the Combined Second Long-Range Forecast with First and Second Supplements of the electricity resources and requirements of the Russell Municipal Light Department ("Russell").

I Procedural History

Russell filed its Second-Long Range Forecast on April 28, 1981.[1] In response to telephone inquiries by the Hearing Officer, Russell supplemented its filing on September 18, 1981.[2] The Council's files contain no record of any additional communication between Russell and the Council staff concerning these filings.

In February 1983, the new Hearing Officer contacted Russell concerning the Council's review of Russell's Forecast. On February 28,

1 The Second Long-Range Forecast consisted of Energy Facility Siting Council ("Council") Table No. E-11, and a cover letter explaining that Russell had "no reason to believe there will be any substantial change in the near future."

2. The supplemental information consisted of Council Table Nos. E-8 and E-24, and a copy of the rate schedule of Western Massachusetts Electric Company ("WMECO") covering sales of power to Russell.

The Council also has recognized that small all-requirements utilities occupy a special position in regard to economic forecasting. In particular, the power requirements of these utilities are small in comparison to those of their wholesale suppliers. Secondly, the large suppliers include forecasts of "sales for resale" to small utilities in their own annual filings with the Siting Council.[6] Thus, for a system like Russell, accurate historical data, which can be utilized for forecasting purposes by the large supplier, may be more important than precise projection methods. Chester Municipal Electric Light Department, 6 DOMSC 152, 154 (1981).

Given the foregoing considerations, the Council finds that Russell's Second Long-Range Forecast, and the First and Second Supplements thereto, are appropriate, reviewable, and reliable.[7] The Council appreciates Russell's cooperation in supplying the annual Supplements and the additionally requested information to the Council.

III Analysis

Russell serves approximately 350 residential customers and a handful of commercial and municipal customers.[8] Russell has no industrial customers. Most of Russell's residential customers do not

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6 See generally, Brown, J.P., Review of Small Electric Co. Demand Forecasting (EFSC Research Paper, April 14, 1981). The Northeast Utilities System considers Russell's estimates of energy purchases and peak loads in its most recently-filed Supplement. Northeast Utilities System, (Docket No. 83-17) (Annual Supplement at 14).

7 Although the present Docket originally covered only Russell's Seocnd Long-Range Forecast, the Supplements filed in 1982 and 1983 are incorporated herein for decision. Rule Nos. 14.1(2), 15.5, Mass. Admin. Code Tit. 980, Sec. 1.04(1)(b), 1.05(5).

8. Approximately one-half of the Town of Russell is served directly by WMECO.

or no growth is projected.[12] The Council encourages Russell to reassess these projections in light of this discussion.

In the commercial class, Russell projects an annual growth rate of approximately one-half of a percent over the Forecast period. The Council finds this projection reasonable based on lack of growth potential as compared to the somewhat higher yearly growth rates of between one and three percent projected by the Northeast Utilities System for WMECO.[13]

Russell projects that municipal use will increase by a little less than one percent annually throughout the Forecast period, and that streetlighting use will remain constant in this time frame. Also, Russell forecasts a one percent yearly growth in both summer and winter peak load.[14] Russell bases these projections on historical data which have been supplied to WMECO as well as to the Council. The Council does not find these predictions to be unreasonable, and is satisfied that the Council's goal of providing the wholesale supplier with statistical information has been met.

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12 The average use per residential customer without electric heat since 1975 has varied from a low of 4864 Kwh/year in 1975 to a high of 5429 Kwh in 1979. However, no trend in the historic figures is discernible. Again, the Council notes that NUSCO has projected a decline in average use per customer in this category. Northeast Utilities System, (Docket No. 83-17, Annual Supplement at II-46).

13 Northeast Utilities System, (Docket No. 83-17, Annual Supplement at II-50).

14 Russell experienced its historic peak winter load of .792 MW in the winter of 1981. The highest summer peak load of .588 was experienced in 1982.

1983, Russell submitted a copy of Council Forms TR-1 and TR-2[3] previously filed with the Council in July 1982. Russell complied with the Council's publication and posting requirements in April 1983. No petitions to intervene were received by the Council. On June 15, 1983, the Hearing Officer met in Russell with the manager of the Russell Municipal Light Department to discuss the Forecast and Supplement.[4] The discussion yielded information which enhanced the review of the Forecast. In addition, pursuant to an agreement reached at the meeting on June 15, 1983, Russell submitted updated versions of Council Forms TR-2 and TR-1 on June 17, 1983. The Council appreciates Russell's cooperation in providing the requested information.

II Standard of Review

The Council applies a three-pronged standard on a case-by-case basis to determine whether a forecast is reasonable.[5] A forecast must be (1) appropriate or technically suitable for the size of the utility; (2) reviewable in the sense that results can be duplicated and evaluated by another person with the same information; and (3) reliable in that the assumptions, judgements and data utilized will lead to a forecast with a high probability of occurrence. See Nantucket Electric Company, 8 DOMSC 257, 260 (1982).

3 These Forms contain data for annual supplements and a narrative description of the data.

4 A letter dated June 6, 1983, from the Hearing Officer to Russell containing certain questions on the Forecast and Supplement served as an agenda for discussion. The letter requested information on: the number of customers in various classes for the years 1975-1982 and a projection of the number of customers for the Forecast period; historic and projected consumption of municipal buildings; and the potential for conservation.

5 Russell's Fourth Annual Supplement to its First Long-Range Forecast was approved without condition. Russell Municipal Light Department, (Docket No. 80-31, May 1, 1981).

utilize electric heat. Russell is served by Western Massachusetts Electric Company ("WMECO") under an all-requirements wholesale power agreement.[9] The agreement specifies no limit on the amount of power which can be purchased by Russell.

Russell relies on historical data and knowledge of impending changes in its service territory in making projections. Russell states that virtually no lots are available for either residential or commercial construction so that there is little new building. Accordingly, Russell forecasts a yearly one percent growth rate in total energy sales over the Forecast period.[10] As part of this composite rate, Russell projects that sales to residential customers with electric heat will grow by between one-half and three quarters of a percent per year during the Forecast period. The Council questions this prediction because the average yearly use per customer in this category has declined substantially each year since 1976 although the number of customers is almost constant.[11] In regard to residential customers without electric heat, Russell projects a compound yearly growth rate of approximately 1.25 percent. This forecast also is subject to question in light of the facts that Russell historically has not experienced an annual growth in average use per customer in this category and little

9. Russell has no plans to alter the agreement with WMECO. Additionally, Russell has experienced no problems with service from WMECO under the agreement.
10. Russell's 1980 Supplement indicated a 0.9% compound annual growth rate for total requirements for 1980-1989, as compared to a 2.4% rate projected in the 1979 Supplement. Russell Munic. Light Dept. (Docket No. 80-31, May 1, 1981).
11. In 1976 the average consumption for residential customers with heat was 25,748 Kwh/year. Further, these averages are significantly higher than the corresponding averages reflected by the Northeast Utilities System. ("NUSCO"). Further, NUSCO predicts a decline in average electricity use in this category. Northeast Utilities System, (Docket No. 83-17, Annual Supplement at II-46.)

IV ORDER

The Council hereby APPROVES Russell's combined Second Long-Range Forecast and First and Second Supplements. Russell's Third Supplement shall be due on April 1, 1984.

Energy Facilities Siting Council

By James G. White, Jr.

James G. White, Jr., Esq.
Hearing Officer

This Decision was approved by unanimous vote of the Energy Facilities Siting Council by those members and designees present and voting: Sharon M. Pollard, Chairperson; Sarah Wald (for Secretary Paula Gold); Marie Yager (for Secretary James ~~S.~~ Hoyte); Harit Majmudar (Public Electricity Member); Robert Gillette (Public Environ~~mental~~ Member).

August 12, 1983

Date

Sharon M. Pollard

Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the First Annual Supplement to the Second Long-Range Forecast of the Middleborough Gas Department	)	EFSC No. 83-18

FINAL DECISION

Douglas I. Greenhaus, Esq.
Hearing Officer

Introduction

The Middleborough Gas and Electric Department (hereinafter "the Department") is a "gas company" as defined under the regulations of the Massachusetts Energy Facilities Siting Council (hereinafter "the Council" or "the EFSC"). EFSC Rule 3.3, 980 CMR 2.03. Pursuant to the provisions of M.G.L.c. 164, sec. 69I, the Department filed its 1982 Gas Forecast Supplement on February 25, 1983.

Of the Commonwealth's fourteen gas companies, the Department is ranked eleventh in size. As a small Department, Middleborough has a good first hand understanding of its service territory. Many of the Department's assumptions were appropriately based on this understanding. The Department has a service territory with an expanding population of about 16,377. Growth on the system due to new construction has been relatively small in part because the Department does not conduct an active program of marketing activities.

Summary of the Proceedings

On March 4, 1983, the Department was ordered to post Notice of Adjudicatory Proceeding. EFSC Rule 13.2, 980 CMR 1.03(2). Following the Notice period, no persons requested to intervene or otherwise participate in the proceedings. A set of Information Requests was issued on June 27, 1983, the answers to which were received on August 3, 1983. An informal technical session was held on September 1, 1983. Following review of the Department's Forecast and its response to the Council's discovery, the Hearing Officer wrote and issued a Tentative Decision which was submitted to the Council for its approval.

Analysis of the Forecast

A. Review Criteria

Under EFSC Rules 69.2 and EFSC Rule 66.5, the Council is required to apply several criteria to its review of gas company forecast supplements. First, the Department must submit a reviewable forecast supplement. Second, such supplement must be an appropriate filing for the system under consideration. Lastly, the supplement must be reliable in its ability to forecast future gas requirements and sendout.

The Department's methodology and description thereof was approved by the Council in EFSC No. 81-18. See, 8 DOMSC 41-47 (1982). Therefore, this Decision will focus on the Department's changes to the forecast methodology and on further specific concerns which exist with regard to the forecast. See, EFSC Rule 68.

B. Design Methodology

In planning for a design winter, the Department currently uses a degree day total of 6,799 which reflects the sum of the coldest heating and coldest non-heating seasons actually experienced by the Department over the past 25 years. The Council would like to suggest that the Department's methodology is, in this instance, perhaps too conservative.

In EFSC No. 81-18, the Council suggested that the Department's prior use of an average of the five highest split-years over the past 25 was too understated. To simply utilize the coldest split-year actually experienced would bring the Department in line with the majority of gas utilities currently filing forecasts with the Council. By doing so, the Department's design-year degree day total will fall somewhere in between 6,493 and 6,799.

In sum, while the Council must insure that the Department is able to meet the gas needs of its system, the Council assumes that undue costs are often associated with overplanning and that a likelihood exists that such costs may be incurred if an overly conservative design-year figure is used for planning purposes.

C. Forecast of Sendout Requirements

1) Residential

The Department's Sendout Forecast Methodology was approved by the Council as part of its last Decision, EFSC No. 81-18. See, 8 DOMSC 41, 43 (June 21, 1982). In the present Forecast Supplement, the Department has raised an issue which is of particular concern to the Council. The problem stems from adjustments that the Department has been making to their computer billing and record system. As expressed by the Department, their present system has resulted in "sendout data by Customer Class [being] less than desirable." 1983 Forecast Supplement at 6.

The Council staff has inquired of the Department as to when it will make the necessary changes to its computer programs and customer records so as to obtain accurate customer class sendout data. In response, the Department has stated that starting in February of 1983, a major revision in its customer billings and records program was begun.

The new system will identify and separate the substantial number of its customers located in multiple dwelling units which do not have a central heating system. By doing so, the Department intends to avoid a distorted calculation of average use per heating customer. In addition, the new system will separate Municipal class customers into heating and nonheating. In sum, the planned modifications will enable the Department to obtain accurate customer class sendout data that will provide for a benchmark to monitor effects of energy conservation and provide for a sound basis for future forecasts.

The Council appreciates the Department's efforts aimed at obtaining accurate sendout data. It notes that as of September 1, 1983, the Department had not yet achieved this objective. The Council wishes to stress its concern that the new data system be completed as soon as is practical. The Council recognizes that the Department's forecast methodology cannot fully be utilized until sufficiently accurate data has been incorporated into it. Therefore, approval of this forecast is conditioned upon the Department's obtaining accurate sendout data in the future.

2) Industrial

The Council notes that the Department foresees no growth in the Industrial class over the next five years and simply cautions the Department to keep the Council abreast of any changes in this customer class forecast.

3) Interruptible

Originally the Department projected a sharp reduction in its Interruptible sendout due to loss of its largest interruptible customer. In addition, the Department noted that Algonquin Gas Transmission Company had indicated that I-1 gas would not be available past the summer of 1983. As of September 1, however, the Department stated both that it's interruptible customer was again back on the system and that Algonquin would continue to offer I-1 (as well as I-2) gas to the system.

4) Commercial

In the Commercial class, the Department projects an 11.5 percent growth over the next five years based on historical commercial building activities and information received from developers, builders and the Town's Development Coordinator. Seventy percent of this growth will be comprised of a conversion of the Town of Middleborough's Municipal Buildings from oil to gas. The balance will be due to projected new Commercial construction.

5) Sales For Resale

No growth for this customer class has been projected. Sales for Resale consist of sales to Bay State Gas Company for fourteen customers in the Town of Lakeville and are forecasted based on normalized sendout.

6) Company Use and Unaccounted For

The Council wishes to laud the Department for making efforts at evaluating and, where necessary, correcting metering problems which had in the past resulted in an unreasonably large sendout figure in the Company Use and Unaccounted For class. Figures of 7-7.4 MMCF per year (roughly 2 percent of total sendout) have been projected for the next five years.

D. Conservation

In EFSC Docket No. 81-18, the Council made it an explicit condition to the approval of the forecast that the Department "incorporate its conservation judgements into its forecast preparations." 8 DOMSC 45 (June 22, 1982). This Condition included a requirement that residential customer class data be disaggregated by heating and non-heating subclasses. 8 DOMSC 41, 45 (June 21, 1982).

The Department has described few significant steps with regard to conservation in its 1983 Forecast Supplement. Due to several problems with its ability to accurately calculate customer class sendout, the Department states that is is as yet unable to accurately demonstrate the effects of energy conservation by customer class. In the future, the Department plans to utilize corrected billing cycle transaction registers which will provide accurate customer sendout data by customer classification. Changes to the computer programs and customer records used by the Department are scheduled to be made in 1983.

For 1983, the Department aims to utilize its available manpower "to examine energy conservation programs and energy conservation information dissemination to [its] customers". Forecast Supplement, at 5. (February 25, 1983).

At this time, the Department is considering the dissemination of two types of informational materials to its customers. The first type is a series of informational sheets covering numerous topic areas of residential conservation. To be available at the Department's offices, these informational sheets will cover such topics as waterheaters and weather stripping.

The second type of printed material which the Department is considering is described as a document dealing both with energy conservation and general information concerning the Department.

The Department is also considering the implementation of a residential "Energy Mizer" heating equipment maintenance program. It is anticipated that this program will become available to the Department's customers under a non-solicited basis in the Fall of 1983 and on a solicited basis by Fall of 1984. The program is aimed at preventative maintenance, burner efficiency and burner safety control.

The Department notes that residential customers have been turning off gas service in the Spring and resuming service in the Fall. This service is being provided to the customer at no additional cost. Lastly, the Department has planned a waterheater/water piping insulation program for implementation in 1984 or 1985. In addition to the aforementioned planned programs, the Department notes that it is a sponsoring member of Mass-Save. The Department reports that in the first two years of participation in the Mass-Save program, the residential customer response rate was 1.1 percent.

As a Condition for the approval of this forecast, the EFSC orders the Department to continue to develop its conservation programs and, in addition, to seek ways in which it might increase participation of its residential customers in Mass-Save or provide it's customers with an alternative. The Department has mentioned the possibility of joint insulation projects aimed at achieving this objective.

The Council wishes to reemphasize its belief in the importance of incorporating conservation projections into a disaggregated forecast. The Department should take whatever steps are necessary to achieve this end. The Condition set out in EFSC Docket No. 81-18 with respect to this subject is therefore repeated for purposes of this forecast.

E. Analysis of Supply

The Department has available to it several diverse sources of gas supply which are outlined in the table below:

Heating Season Supplies and Sendout
(MMCF)

SOURCES OF GAS	1982-82 Total Supply Available	Normal Firm Sendout	1986-87 Total Supply Available	Normal Firm Firm Sendout
Algonquin F-1	124.546(50%)	109.251(58%)	123.552(47%)	110.118(56%)
ST-1	3.030 (1%)	.842(45%)	3.030 (1%)	.890(45%)
SNG-1	17.280 (7%)	17.280 (9%)	17.280 (7%)	17.280 (9%)
Propane	22.204 (9%)	-	22.204 (9%)	-
Vaporized LNG	79.725(32%)	58.225(31%)	91.600(35%)	68.100(34%)
LNG Storage	3.003 (1%)	1.500 (1%)	3.455 (1%)	1.500 (1%)
Total	249.788(100%)	187.098(100%)	261.121(100%)	197.888(100%)
Design Year Requirements	202.440		214.113	

1. Based on 50% back-off of available contracted for SNG.

The Department has three existing peak shaving and storage facilities which include an LNG plant, a propane plant and a Hortonsphere. The combination of these facilities results in a Department storage capacity of 8.100 MMCF and a maximum daily sendout capacity of 1.79 MMCF.

As illustrated in the table above, the Department will have available to it the necessary resources to meet its design year (and thus its normal year) requirements. Additionally the Department has a peak day sendout capability of 3.897 MMCF/Day. When compared to a 1986-87 peak day sendout requirement of 2.526 MMCF/Day, it is evident that the Department has the necessary peak day resources to meet its peak day sendout requirements.

F. Contingency Planning

In EFSC Docket No. 81-18, the Council asked that the Department present "an analysis of its plans for meeting the demand of its customers in the event each of its major gas supplies is disrupted." 8 DOMSC 41. 47 (June 21, 1982). In response to this condition, the Department submitted as part of their forecast a section entitled "Middleborough's Gas and Electric Department's Maintenance and operations Manual-Section 1900-Volume 3". This document is quite comprehensive and serves well to satisfy the Council's prior condition. The EFSC asks that any future changes made to the Manual be submitted as part of the appropriate forecast.

In the event that the Department suffers total or partial loss of its F-1 or SNG supply, interruptible customers will be told to switch to standby fuels and additional LNG and Propane will be ordered. If S.T.B. volumes become unavailable, they will be replaced with Bay State, Hortonsphere LNG or propane-air gas. In the event that LNG sendout becomes unavailable, Bay State or propane-air gas will be used for replacement purposes. Supplies for LNG storage can be replaced with propane should an alternate supplier be unavailable. Likewise, LNG gas may be utilized if propane-air sendout is unavailable and pipeline sources cannot provide additional volumes. Should the Bay State interconnection gas become unavailable due to curtailment or supply interruption, interruptible customers will be asked to switch fuels and available LNG and/or propane air supplies will be ordered. If Hortonsphere gas becomes unavailable to the system, the Department plans to replace lost volumes either through the Bay State interconnection, or with LNG or propane-air.

G. Decision and Order

The Department has assembled a forecast supplement which meets the Council's "appropriate, reviewable and reliable" standard. Therefore, the Council, subject to the Conditions listed on page 5, hereby APPROVES the 1983 Long-Range Gas Forecast Supplement of the Middleborough Gas and Electric Department. The next supplement will be due on July 1, 1984.

Energy Facilities Siting Council

by Douglas I. Greenhaus

Douglas I. Greenhaus, Esq.
Hearing Officer

Dated in Boston this 26th day of October, 1983.

This decision was unanimously approved by the Energy Facilities Siting Council at its meeting on October 25, 1983, by those members present and voting.

Voting in Favor: Ms. Sharon Pollard, Chairperson; Mr. Steven Roop, for the Secretary of Economic and Manpower Affairs; Ms. Sarah Wald, for the Secretary of Consumer Affairs; Mr. Richard Croteau, Public Labor Member; Mr. Thomas Crowley, Public Engineering Member; and Mr. Robert Gillette, Public Environment Member.

October 26, 1983
Date

Sharon M. Pollard
Sharon Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Berkshire Gas Company for Approval of the Second Supplement to its Second Long-Range Forecast of Gas Resources and Requirements	)	EFSC No. 83-19

FINAL DECISION

Lawrence W. Plitch, Esq.
Hearings Officer

On the Decision:

Karen Grubb
Economist

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I. INTRODUCTION AND HISTORY OF THE PROCEEDINGS

The Council hereby APPROVES, conditionally, the Second Supplement to the Second Long-Range Forecast of Gas Resources and Requirements of the Berkshire Gas Company ("Forecast").

The Berkshire Gas Company ("Berkshire" or "the Company") is a Massachusetts corporation engaged in the distribution and retail sale of gas in nineteen communities in Berkshire, Franklin, and Hampshire counties. The Company has approximately 26,300 customers.

Berkshire filed its Forecast on August 3, 1983. The Council then ordered publication of a notice of public hearing and adjudicatory proceedings in newspapers of general circulations within the service area of the Company. There were no intervenors. A Prehearing Conference and Technical Session were held at the Council offices on October 11, 1983. At this session, Staff Information Requests were discussed and written responses were received by the Council. Additional record information was received during the following months and the record was closed on December 1, 1983.

II. PREVIOUS CONDITIONS

The Council's Decision in its review of the Company's most recent Supplement imposed a single condition, as follows:

> "In its next Supplement, the Company shall address the anticipated effects of price decontrol of natural gas on its forecast of sendout. This analysis should 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."

In response, the Company projects that natural gas will remain competitive with No. 2 and No. 4 oil for residential and commercial customers. Berkshire expects the industrial market for natural gas to decline as No. 6 oil prices soften.[1] The current Forecast, therefore, reflects some loss of sales in the industrial and interruptible market.[2]

The Company plans to market the load lost in the industrial sector to residential and commercial customers. Berkshire expects its interstate pipeline gas supplier to adjust its contracts and operations to remain competitive in these markets. Berkshire does not expect substantial pricing changes due to decontrol, and does not anticipate any further changes in accounts receivable.[3]

1. Forecast, Appendix 1.
2. Forecast, Tables G-3(B) and G-4(A).
3. Ib.1.

Based on the evidence presented in the Forecast, and in light of the uncertainty surrounding the effects of price decontrol,it is the Council's opinion that the Company has substantially complied with the condition of EFSC Docket No. 81-19.

However, the Council remains concerned with the way in which the Company plans to market the gas made available from declining industrial sales. Industrial customers tend to use gas evenly throughout the year, whereas heating customers use gas predominantly in the winter. By marketing additional gas to these sectors the Company may be increasing its peak sendout requirements. This concern is addressed in Section III C, infra.

III. SENDOUT METHODOLOGY

A. Normal Year

A "normal year" is defined as a year that is neither warmer nor colder than average. Berkshire analyzed the most recent twenty years of degree day data to calculate the average number of degree days in the heating and nonheating seasons. The Company found 1843 to be the normal number of degree days in a nonheating season and 5653 to be the normal number of degree days in a heating season. Berkshire uses a normal year of 7496 total degree days.[4]

Berkshire's forecast of sendout by class for the 1983-84 and 1987-88 years is provided in Table 1. Residential heating customers make up 48% of total sendout requirements. Industrial sales make up about 12% of total firm load. Sixty-two percent of the Company's total sendout requirements occur during the heating season.

Berkshire's forecasted sendout depends upon historic usage, the number of customers, the number of degree days and the Company's expectations with respect to conservation. Base use and heat use are calculated separately. Figures 1 and 2 provide formulas and examples of residential sendout projections.

1. Customer Use Factors

The forecast of base use for residential heating customers depends upon July/August average usage during the last five years.[5] Conservation is projected to reduce base use by 1.5% per year. The

4. Forecast, Table DD.
5. Staff Information Requests, Attachment SR-8.

conservation-adjusted base factor is multiplied by the average number of customers and then by 5 months, 7 months or 12 months to find total base use for a heating season, nonheating season or year.

Berkshire's Forecast of heating use for residential heating customers depends upon actual residential heat sensitive usage as taken from Company billing data. Heating use per customer per degree day is arrived at by subtracting base use per customer from total sendout per customer and dividing the result by the number of degree days. Conservation is projected to reduce use per degree day by 1.5% per year. Heat sensitive usage is forecast by multiplying use per degree day by the number of degree days in a normal year (or season) by the average number of customers.

TABLE 1

Forecast of Sendout by Class
Normal Year
(MMCF)

CUSTOMER CLASS	1983-84 Nonheating Season	1983-84 Heating Season	1987-88 Nonheating Season	1987-88 Heating Season
Residential Heating	701	1377	692	1354
Residential Nonheating	94	120	87	109
Commercial	528	847	536	841
Industrial	269	239	247	219
Company Use and Unaccounted For	32	111	30	109
Total Firm Sendout	1624	2694	1592	2632
Interruptible	600	300	500	200
Total Sendout	2224	2994	2092	2832

Source: Forecast, Tables G-1 through G-5; Company response to verbal information request, received by Council November 21, 1983, (corrections to filed tables).

FIGURE 1
RESIDENTIAL HEATING

A. HISTORICAL USAGE

(1) Base Use Per Customer
Formula:

$$\text{Base Use} = \frac{(12\ \text{mo.})\ [\text{July MCF} + \text{August MCF}]/2}{\text{Avg. Number of Customers}}$$

Example: 1981-82

$$\text{Base Use} = \frac{12\ (45090 + 41019)/2}{14127} = 36.6\ \text{MCF/Cust.}$$

(2) Heat Use Per Customer
Formula:

$$\text{Use/DD} = \frac{\left(\frac{12\ \text{mo. Sendout}}{\text{Avg. No. Cust.}}\right) - \text{Base Use}}{12\ \text{mo. DD}}$$

Example: 1981-82

$$\text{Use/DD} = \frac{\left(\frac{2012.4\ \text{MMCF}}{14127}\right) - .0366\ \text{MMCF}}{7166} = .0147\ \text{MCF/DD}$$

B. FORECAST SENDOUT

(1) Heating Season Sendout = Base Sendout + Temp. Sensitive Sendout
Formula:
Base Sendout = (Base Use/Cust.) (No. Cust.) (5 months)
Temp. Sensitive Sendout = (Heat Use/Cust./DD) (No. Cust.) (Normal No. Heating Season DD)
Example: 1985-86
Base Sendout = (35.9) (15,600) (5/12) = 233,350 MCF
Temp. Sensitive Sendout = (.0128) (15,600) (5653) = 1,128,791 MCF
Total Sendout = 1,362 MMCF

(2) Nonheating Season Sendout = Base Sendout + Temp. Sensitive Sendout
Formula:
Base Sendout = (Base Use/Cust.) (No. Cust.) (7 months)
Temp. Sensitive Sendout = (Heat Use/Cust./DD) (No. Cust.) (Normal No. Nonheating Season DD)
Example: 1985-86
Base Sendout = (35.9) (15,600) (7/12) = 326,690 MCF
Temp. Sensitive Sendout = (.0128) (15,600) (1,843) = 368,010 MCF
Total Sendout = 695 MMCF

Sources: Staff Information Request, Attachment SR-8;
Forecast, Table G-1.

FIGURE 2
RESIDENTIAL NONHEATING

A. HISTORICAL USAGE

Average Use Per Customer

Formula:

Average Use = [(Total Sendout)/(Avg. No. Cust.)]

Example: 1981-82

Average Use = 227/9018 = .0252 MMCF

B. FORECAST SENDOUT

Total Sendout

Formula:

Sendout = (Avg. No. Cust.)(Avg. Use per Cust.)

Example: 1985-86

Sendout = (8500)(.0241) = 205 MMCF

Source: Forecast, Table G-1.

The Company expects conservation to reduce heat sensitive usage for the following reasons:[6]

- two-thirds of Berkshire's customers have used gas heat for 15 or more years, so significant heating equipment replacements are anticipated during the forecast period, and

- according to the Company, "the Berkshire service territory is an area in which energy conservation measures are widely utilized."

Average use for residential nonheating customers depends upon historical average usage during the past five years, as taken from the Company's billing data. Conservation methods are projected to reduce average use by 1.5% per year during the forecast period.

6 Staff Information Requests, SR-4.

The Company forecasts sendout for commercial heating and nonheating customers separately. For heating customers, Berkshire estimates the base and heating factors from billing data using the residential heating formula above. For commercial nonheating customers, Berkshire estimates average use as it does for residential nonheating customers above. Total commercial sendout is the sum of heating and nonheating sendout. Although the number of customers increases during the next five years, sendout remains virtually unchanged due to adjustments in the base and heating factors for conservation.

All industrial sendout is considered base use by Berkshire. Sendout decreases about 8% during the next five years. The Company estimates 90% of the decline to be the result of decreased industrial activity and decreased use of natural gas in favor of oil. The remainder is due to adjustments in the base factor to reflect the Company's expectations of conservation in this sector. The Company obtains this information from contacts with individual industrial customers.

The Council would be better able to review future filings if the Company provided, at the time of its initial filing, the data which is the basis for its customer usage projections. Therefore, the Council Orders that the Company, in its next Supplement, provide the previous five year actual base and heating factors for each class of customer.

2. Customer Projections

The Company projects that the average number of residential customers with gas heat will grow by 336 during 1983-84 and by about 200 per year during 1984-88. During 1983-84, approximately 15% of the projected residential additions are attributable to the conversion of a master-metered commercial housing facility to individually metered residential heating accounts. Approximately 30% of the additions are expected to be new services. The remaining 55% are existing nonheating customers who are expected to add gas heat. In all, 85% of the forecasted additions are conversions from alternate heating fuel and new housing starts.[7]

For the period 1984-88, 10% of new heating load is projected to be due to new housing starts, 25% to be existing nonheating customers adding heating load, and 65% to be new or reactivated services. About 90% of the heating load additions are expected to be conversions from oil.

The number of new or reactivated services as a percentage of total additions doubles after 1984, but in actual numbers it only increases from 100 to 130. This is consistent with the Company's expectations about the competitiveness of natural gas with home heating oil. The decrease in existing customers expected to add heating load is primarily due to saturation.

7. Staff Information Requests, SR-2.

The number of residential customers without gas heat is projected to decline during the forecast period due to conversions to gas heat. Although the number of customers converting was greater in previous years, the Company forecasts that such conversions will level off at 50 per year by 1984.

The Company believes that "The greatest potential for growth is in the commercial sector".[8] An average of 35 new customers per year were added during the past five years. During the forecast period the Company expects to add 50 new commercial customers per year in response to improved economic conditions. Improvements to the distribution system, as well as unused commercial lines, will allow the Company to commit new commercial load.

The Company had identified two industrial customers that it expects to lose between 1984 and 1988. This is attributed to a projected decrease in use of natural gas in favor of industrial fuel oil. It is consistent with the Company's expectations that No. 6 fuel oil will become increasingly price competitive with gas during the forecast period.[9]

The Council notes that the main basis for the Company's forecast of number of customers is their analysis of previous year's data tempered with judgement. Although the Company's projections may be reasonable, in future Forecasts the Council would like to see evidence to support the Company's judgements. Therefore, it is made a Condition to approval that the Company provide, in its next Supplement, documentation to support the Company's judgments in its forecast of number of customers within each class.

B. Design Year

A "design year" is defined as the coldest year for which the Company plans to meet its firm customer requirements. The Company uses a design year of 8140 degree days, the coldest year experienced from April 1961 to March 1981.

To forecast design year sendout, the Company uses the same formulas as for a normal year. Berkshire uses the same number of customers and base load factors, but uses higher heating factors to reflect the fact that higher gas consumption per degree day occurs during the coldest weather. Heat factors are based on the previous five year average of January use per degree day.

C. Peak Day

A "peak day" is the coldest day that is likely to occur during the forecast period. The Company uses 74 degree days as its peak day, which is colder, by one standard deviation, than the average temperature of the coldest day during the past thirty years.

8. Staff Information Requests, SR-5.
9. Forecast, Appendix 1.

The Company's first step in determining its forecast of peak day sendout is to obtain an historical basis. Sendout is based on an average of the sendout on the peak days in each of the previous five years, divided by the corresponding average number of degree days. This historical peak day usage factor is not disaggregated into heating and base components. As a result, the Council is concerned that the Company's methodology may underestimate future peak day requirements.

The Company next factors in its projected aggregate net load growth to the historical peak day usage that it derived. Because the Company is expecting additions from the heat sensitive residential and commercial sectors to replace lost industrial and residential nonheating customer load, there is an additional danger of peak usage forecast error. This is due to the fact that the characteristics of the customers being added are different from the characteristics from which the heating factor was derived. This effect reinforces the bias above if peak requirements are underestimated.

The Council is also concerned about the Company's adjustments for conservation. These adjustments are made after load growth is added, which is appropriate when new and existing customers are similar in their conservation behavior. If, however, new residential customers have, on average, newer homes and different conservation behavior, then peak requirements are underestimated and further downward bias is introduced.

The Council's final concern has to do with the appropriateness of discounting peak day heating factors for conservation. The Council has heard conflicting reports of conservation on peak and would, therefore, like to see more evidence on this from the Company before such adjustments are made in future filings.

In all, the Staff finds four potential sources of downward bias in the Company's peak day sendout projections. Although the Company's methodology may be appropriate, the Forecast lacks adequate documentation to allow the Council to review the filing for reliability. Therefore, approval of this forecast is conditional upon the Company meeting with the Council Staff within 90 days to discuss Berkshire's peak sendout methdology. Attached hereto is Condition 1.

IV. RESOURCES

A. Pipeline gas

Berkshire's largest supplier is the Tennessee Gas Pipeline Company ("TGP"). The Company receives an annual volumetric limitation of 5,256.6 MMCF with a maximum daily quantity of 19.9 MMCF. This contract expires in November, 2000. The Company does not anticipate any curtailment from Tennessee within the forecast period.[10] The Company has a precedent agreement for Canadian gas as part of Boundary Gas Project ("Boundary"), due to commence in 1986. Berkshire will receive an annual quantity of 365 MMCF firm with a maximum daily quantity of 1.0 MMCF/day. Transportation for the Boundary gas will be provided by TGP. The project is awaiting consideration by FERC.

The Company contracts with the Penn-York Energy Company for 400 MMCF of underground storage, 2.3 MMCF/day firm transportation, and 1.3 MMCF/day best efforts transportation. These contracts expire in March 1995. In addition, Berkshire contracts with the Consolidated Supply Company for underground storage capacity of 140 MMCF and 1.3 MMCF/day firm transportation. These contracts expire in April, 2000.

B. Liquefied Natural Gas ("LNG")

The Company purchases LNG from the Distrigas of Massachusetts Corporation ("DOMAC") and receives an annual quantity of 290 MMCF, with a maximum daily quantity of 1.3 MMCF firm. The Company can store 25 MMCF in DOMAC LNG tanks between shipments. Since the LNG facilities lie within the Boston Gas Company service territory, Berkshire has a displacement contract with that Company.[11] Upon demand from Berkshire's gas dispatcher, DOMAC releases LNG to Boston Gas, which vaporizes the volumes and injects them into its system. In return, Berkshire's gas dispatcher orders the same volumes from Tennessee, who charges Berkshire for transportation and charges Boston Gas for the volumes transported. Gas is ordered through displacement on a daily basis. It is received at various stations within each division of the Company's service territory.

In addition, Berkshire has a contract with the Bay State Gas Company for an annual 200,000 MMBtu LNG (or 205 MMCF)[12] of which 150 MMBtu (or 153 MMCF) are take or pay. All LNG from Bay State is received through displacement on the TGP pipeline. Berkshire is entitled to 200 MMCF of storage and 4 MMCF/day firm transportation. This contract is due to expire in March, 1988.

10. Staff Information Requests, S-1.
11. Staff Information Requests, S-4.
12. Conversion factor of 1.025 MCF/MMBtu as per Staff Information Requests, SR-10.

C. Propane

The Company has two propane contracts with the Warren Petroleum Company for a total of 1,500,000 gallons (138 MMCF)[13] annually. These contracts are renewed annually.[14]

The Company is also a customer of the Commonwealth Petroleum Company. Berkshire plans to utilize the remaining 401,000 gallons (37 MMCF) of the contract by March 31, 1984. At that time, Berkshire will review the total requirements of the Company for the following twelve months. According to Berkshire:[15]

> "In conjunction with that review will be an analysis of Commonwealth's competitive strength (price, deliverability, pipeline allocation) to determine a contract renewal".

Berkshire has five liquid propane air facilities in various locations within its service territory, with total storage capacity of 65 MMCF and total vaporization capacity of 14 MMCF per day.

V. COMPARISON OF RESOURCES AND REQUIREMENTS

Resources and sendout requirements are compared to evaluate the Company's ability to meet customer sendout requirements in normal and design years, peak days and cold snaps throughout the forecast period. We will also consider the adequacy of Berkshire's supply in the event of a potential delay in any DOMAC shipment from Algeria.

A. Normal Year

During a normal year the Company must meet its firm sendout requirements and refill storage. About 60% of Berkshire's firm requirements occur during the heating season. The Company refills storage during the nonheating season when sendout requirements are lower in order to begin each heating season with full inventories.

Tennessee pipeline gas provides the vast majority of the Company's supply - approximately 93% of the heating season load and 96% of the nonheating season load. Propane is used exclusively during the winter months as a peak shaving resource. LNG is used during both seasons, although nonheating season LNG is delegated to the swing months. Combined, these supplementals constitute only a small fraction of total

13. Convesion factor of 10.89 gallons/MCF as per Staff Information Requests, SR-9.
14. Staff Information Requests, S-3.
15. Staff Information Requests, S-2.

heating season load. Boundary gas, due to come on line by winter 1985-86, is expected to comprise 5% of total heating supply and 8% of total nonheating season load.

The Council is satisfied that Berkshire has adequate resources to meet the requirements of a normal year.

B. Design Year

Requirements and potential supply sources for design years are summarized on Tables 4 and 5. The requirements of design heating and nonheating seasons reflect the coldest weather during which the Company should be prepared to meet the demand of its customers.

For each heating season, firm sendout requirements are about 4% greater in a design year than a normal year. It is imperative that an adequate and reliable supply be available to meet the special needs of a design winter.

Several feasible alternatives exist. For example, a fraction of the gas that would have been sold to interruptibles in a normal heating season could be diverted to meet the requirements of a design winter. In addition, Berkshire is entitled to quantities of LNG above the normal take which, in and of themselves, are sufficient to meet all of the Company's design requirements. The Company also has enough storage capacity to rely only on stored volumes of TGP pipeline gas and propane. This array of supplemental supply options gives the Company the flexibility to select from several alternatives to meet its design year requirements.

The Council is confident that adequate supply exists for Berkshire to meet design year requirements of both heating and nonheating seasons during the forecast period.

C. Peak Day

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.

Table 6 summarizes Berkshire's peak day resources and requirements. Requirements for a peak day reflect the energy necessary to meet the needs of a 74 degree day.

TABLE 2
COMPARISON OF RESOURCES AND REQUIREMENTS (MMCF)

Normal Year - Heating Season

REQUIREMENTS	1983-84	1984-85	1985-86	1986-87	1987-88
Normal Firm Sendout	2694	2672	2658	2645	2632
Interruptible Sendout	300	350	450	450	400
Requirements	2994	3022	3108	3095	3032
RESOURCES					
TGP-CD	2498	2506	2552	2539	2476
TGP-Storage	300	300	200	200	200
Boundary	-	-	150	150	150
Propane	50	70	60	60	60
LNG	146	146	146	146	146
Total Requirements	2994	3022	3108	3095	3032

TABLE 3
COMPARISON OF RESOURCES AND REQUIREMENTS (MMCF)

Normal Year - Nonheating Season

REQUIREMENTS	1984	1985	1986	1987
Normal Firm Sendout	1609	1602	1597	1592
Tennessee Storage Refill	330	200	200	200
Interruptible Sendout	550	750	850	850
Total Requirements	2489	2552	2647	2642
RESOURCES				
TGP-CD	2054	2247	2127	2122
TGP-Storage	330	200	200	200
Boundary	-	-	215	215
LNG	105	105	105	105
Total Resources	2489	2552	2647	2642

Source: Forecast, Tables G-5, G-22, G-24; 1983 SEC Form 10K, page 5.
Total

TABLE 4
COMPARISON OF RESOURCES AND REQUIREMENTS (MMCF)

Design Year - Heating Season

REQUIREMENTS	1983-84	1984-85	1985-86	1986-87	1987-88
Design Firm Sendout	2813	2790	2776	2762	2765
Normal Firm Sendout	2694	2672	2658	2645	2632
Excess of Design over Normal	119	118	118	117	133
RESOURCES					
TGP-Storage	70	100	100	100	100
Propane - Storage	107	70	40	40	40
LNG above Forecast	185	185	185	185	185
Propane above Forecast	-	-	-	-	-
Interruptible Sendout	300	350	450	450	400
Total Firm Resources	662	705	775	775	725

TABLE 5
COMPARISON OF RESOURCES AND REQUIREMENTS (MMCF)

Design Year - Nonheating Season

REQUIREMENTS	1984	1985	1986	1987
Design Firm Sendout	1697	1689	1683	1647
Normal Firm Sendout	1609	1602	1597	1592
Excess of Design over Normal	88	87	86	55
Maximum Storage Refill	70	100	100	100
Total Requirements	158	187	186	155
RESOURCES				
Interr. & Resale Sendout	550	750	850	800

Spot Sources plus excess allowable over taken of Propane and LNG.

Sources: Forecast, Tables G-5, G-22, G-24; 1983 SEC Form 10k, page 5.

Berkshire's system has capacity available that is 20% greater than what is necessary to meet the requirements of its customers on a peak day. This is an appreciable margin, adequately compensating for any uncertainties that the Council may have with reliability of the Company's peak demand methodology. It is the Council's opinion that sufficient peak day resources exist to meet its peak sendout 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.

Berkshire is well prepared to meet the requirements of an extended cold snap. Of its forecast peak sendout requirements of 35.4 MMCF per day, the Company receives 23.4 MMCF/day of pipeline gas. The Company meets the remaining 12 MMCF/day with propane and LNG. Maximum propane use is 13.8 MMCF/day, so the Company can meet supplemental requirements with propane alone if LNG is not available. The Company has 65 MMCF of propane supply on-site. When propane is available to refill storage or the weather is less severe than the Company's defined peak day, the Company's capability to meet cold snap requirements is enhanced even further. In addition, Berkshire can displace 1.3 MMCF/day of LNG for at least 14 consecutive days from Boston Gas.

Consequently, Berkshire depends upon the timely acquisition of propane to avoid dependence on historically unreliable Algerian LNG. As such, it is hereby made a Condition to approval that, in future filings, the Company describe its short term propane purchase procedures, including the time that is needed to contract for and deliver propane and the availability of the transportation that is needed.

TABLE 6

COMPARISON OF RESOURCES AND REQUIREMENTS (MMCF)
Peak Day

	1983-84	1984-85	1985-86	1986-87	1987-88
PEAK DAY SENDOUT REQUIREMENT	35.4	35.2	35.2	35.2	35.2
Peak Day Resources					
TGP-CD	19.9	19.9	19.9	19.9	19.9
TGP-Storage	3.5	3.5	3.5	3.5	3.5
Propane	13.8	13.8	13.8	13.8	13.8
LNG	5.3	5.3	5.3	5.3	5.3
Boundary	-	-	-	1.0	1.0
TOTAL PEAK DAY RESOURCES	42.5	42.5	42.5	43.5	43.5

Source: Forecast, Table G-23.

VI. DECISION AND ORDER

The Council hereby APPROVES the Berkshire Gas Company's Second Supplement to its Second Long-Range Forecast of Gas Needs and Requirements subject to the following Condition:

(1) That the Company shall, within 90 days, meet with the Council Staff to discuss Berkshire's peak day sendout methodology and and explain how the Company accounts for potential sources of downward bias in these projections.

(2) That the Company shall, in its next Supplement, provide the data which is the basis for its customer usage projections, including the previous five year actual base and heating factors for each class of customers.

(3) That the Company shall, in its next Supplement, provide documentation to support the Company's judgements in its forecast of number of customers within each class.

(4) That the Company shall, in its next Supplement, provide a description of its short term propane purchase procedures, including the time that is needed to contract for and deliver propane and the availability of the transportation that is needed.

LW Plitch

Lawrence W. Plitch, Esq.
Hearing Officer

This Decision was unanimously approved by the Energy Facilities Siting Council at its meeting on January 17, 1984, by all members and designees present and voting as follows: Sharon Pollard, Chairperson; Sarah Wald, for the Secretary of Consumer Affairs; Walter Headley, for the Secretary of Environmental Affairs; Joellen D'Esti, for the Secretary of Economic Affairs; Thomas J. Crowley, Public Member, Engineering and Robert W. Gillette, Public Member, Environment.

Sharon M. Pollard

Sharon M. Pollard
Chairperson

January 31, 1984
Date

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Second Supplement to the Second Long-Range Forecast of the Town of Wakefield Municipal Light Department	)	EFSC No. 83-2

FINAL DECISION

Douglas I. Greenhaus, Esq.
Hearings Officer

I. Introduction

The Town of Wakefield Municipal Light Department (hereinafter "the Department" or "Wakefield") is a "gas company" as defined under the regulations of the Massachusetts Energy Facilities Siting Council (hereinafter "the Council" or "EFSC"). EFSC Rule 3.3, 980 CMR 2.03. Wakefield is a small gas system consisting of 5,000 customers, 97% of which are residential. The Department continues to receive its total gas supply from the Boston Gas Company. The Department has no jurisdictional facilities of its own nor does it plan to build or otherwise obtain any such facilities.

II. Summary of the Proceedings

Pursuant to the provisions of M.G.L. c. 164, sec. 69I, the Department filed the Second Supplement to its Second Long-Range Forecast with the Council on September 6, 1983. On September 21, 1983, the Department was ordered to post Notice of the Adjudicatory Proceeding. EFSC Rule 13.2, 980 CMR 1.03(2). Following the Notice period, no persons requested to intervene or otherwise participate in the proceedings. A set of information requests was issued on October 24, 1983, the answers to which were received on November 4, 1983.

Following review of the Department's Supplement and its responses to the Council's information requests, the Hearings Officer wrote and issued a Tentative Decision which was submitted to the Council for its approval.

III. Analysis of the Supplement

Under EFSC Rules 69.2 and 66.5, the Council is required to apply several criteria to its review of gas company forecast supplements. The Wakefield Municipal Light Department, as with all of the gas companies under the Council's jurisdiction, must submit a reviewable forecast supplement, which is an appropriate filing for its particular system and which is reliable in its ability to forecast future gas requirements and sendout. In the past, the Council has determined that in order to satisfy these criteria, Wakefield need only file a simple "narrative" forecast supplement which, in essence, supplements that of the Boston Gas Company. *See, e.g.,* EFSC No. 79-2 and EFSC No. 82-2.

For its Second Supplement to its Second Forecast, Wakefield has again submitted a "narrative" filing. In addition, and in response to comments and Conditions made by the Council in its EFSC No. 82-2 decision, the Department has also provided the Council with a number of tables. This Decision will focus on the Department's supplement from the standpoint of its responses to those comments and Conditions set out in EFSC No. 82-2.

a. Supply: The Boston Gas Contract

Wakefield is under contract with the Boston Gas Company for its total gas supply, a firm supply of gas, over the entire forecast period. A detailed discussion of the provisions of this total requirements contract is found in EFSC No. 82-2.

Since January 1, 1983, the Department has been billed by Boston Gas on an MMBtu basis instead of an Mcf basis. This billing charge is reflected in a contract change agreed to by the Department on November 2, 1982. For contract year 1982-83, the Department's actual take of 308,500 Mcf fell well within its contract limit of 347,288 Mcf, (353,903 MMBtu). 1983 Forecast Supplement at 1. Yearly contract limits are set out in the Table below.

The Council appreciates the Department's submittal of contract volumes for the forecast period. Delivery of these volumes is a direct function of the reliability of the Boston Gas Company. Such reliability is currently the subject of examination in the Council's review of Boston's own 1983 forecast supplement. Boston's filing for 1982 was approved in November of 1982. EFSC No. 82-25.

b. Boston Gas Forecast

The Wakefield portion of Boston Gas's 1983 Forecast Supplement provides a set of forecasted normal year sendout figures for Wakefield. See, Table G-3(c), 1983 Supplement. These figures are compared below to those provided by Wakefield in their Table "Form 7".

TABLE I
Projected Gas Sendout (MCF)

	1983/84	1984/85	1985/86	1986/87	1987/88
Wakefield's Total Forecasted Gas Sales	344,182.6	344,411.3	345,452.9	346,437.1	347,328.4
Boston Gas's Forecasted Normal Sendout in MCF	399,800	351,300	362,800	374,300	365,800
Wakefield's Design Year Forecast	361,386.1	361,786.4	362,970.9	364,032.0	365,066.2
Contract Limits	364,652	382,885	402,029	422,130	443,236

While it appears that Boston Gas has forecasted a substantially greater growth rate for total normal sendout over the forecast period, Wakefield feels that "its figures don't differ greatly from theirs." 1983 Forecast Supplement at 2. Recognizing that Wakefield need not take their full allowable contract amount and is not penalized for doing so, the Council attaches no significance to the fact that Wakefield's figures are more conservative than those of its supplier. There will be more than enough gas available from Boston Gas over the forecast period to meet design year projections.

c. Forecast Methodology

In EFSC 82-2, the Council concluded that the Department's design year methodology resulted in a reasonable figure reflecting the temperature-sensitive nature of each customer class. As a Condition to the approval of that forecast supplement, Wakefield was required to provide a similar design year figure for each of the five forecast years, to reflect forecasted conservation and/or load growth and to update its current year design figure as its actual customer use factors continue to change.

1. Design Year

As is indicated in Table I on page three of this Decision, Boston Gas's Forecasted Normal Sendout exceeds Wakefield's Design Year Forecast in 1986-87. Wakefield's figures indicate a .25 percent average compound growth rate per year. This compares to a .23 percent average compound growth rate per year for Wakefield's projected normal year sendout. Boston Gas, in its Table G-3(c), found infra in Appendix A, indicates a 3.2% compound growth rate in Forecasted Normal Sendout.

The Council finds this not to be a serious discrepency. First, Boston Gas's methodology results in lower customer use factors, and in a much larger increase in the number of customers to the residential classes. Second, Boston Gas does not assume any conservation: Wakefield assumes a 1.5% rate of conservation. The combination of these two differences in methodology results in the discrepancy. Such planning on the part of Boston Gas will only serve to insure an adequate gas supply. In any event, even Boston Gas's projections result in figures below those set by contract.

2. Peak Day

As a Condition of its approval of the Department's last filing, the Council required that Wakefield forecast peak day use for each year of the forecast period. The Department indicated last year that accurate calculations of peak day usage would become available with the installation of a SCADA (Supervisory Control and Data Aquiring) System. The latest projection for installation is calender year 1984. The system's daily gas reading tracking function will be activated in 1985.

In the meantime, the Department has chosen to provide the Council with estimated peak day consumption figures based on the daily heating and nonheating loads of the 82/83 reporting period and on the 58 degree day which occurred on January 19, 1983. Design peak day consumption is projected for the forecast period based on the 73 degree day which occurred on February 9, 1934. Noting that this is the same peak day upon which Boston Gas bases its design day forecast, the Council finds Wakefield's methodology and the resultant figures found in the forecast to be sufficiently reliable.

Wakefield has complied with last year's Condition requiring the computation of peak day use for each year of the forecast period. These figures are listed in the following table:

TABLE II
DESIGN YEAR PEAK DAY

YEAR	HEATING (MCF)	NON-HEATING (MCF)	TOTAL (MCF)
1983/84	2,265.9	453.25	2,719.15
1984/85	2,285.0	444.6	2,734.6
1985/86	2,302.5	448.9	2,751.4
1986/87	2,318.5	450.7	2,769.2
1987/88	2,334.3	447.1	2,781.4

3. Conservation

Last year, the Department forecasted a three percent system-wide decrease in use-per-customer due to conservation but failed to incorporate this figure into its forecast of system growth. In this year's Supplement, the Department forecasts a conservation rate of 1.5 percent for residential loads and one percent for commercial and municipal loads. These figures were calculated based upon an adjustment of heat-related consumption for a normal degree day year and using the actual 1982/83 consumption figures, by class. A comparison was made to the actual and adjusted figures for the 1981/82 time period.

The results of the new conservation calculations fall within the national average of 1.5 to 2 percent per year. See, Information Response No. 4. This range is consistent with the range of figures supplied by the majority of gas companies regulated by the Council. The Council appreciates the Department's use of its conservation figure in projecting sendout requirements. The continued yearly calculation of changes of customer usage due to conservation and the incorporation of such calculations in the forecast will enable the Department to maintain its forecasting accuracy.

Decision and Order

The Council hereby APPROVES the Second Supplement to the Second Long-Range Forecast of the Town of Wakefield Municipal Light Department.

The Third Supplement will be due on July 1, 1984.

Energy Facilities Siting Council

By Douglas Greenhaus fmp

Douglas I. Greenhaus, Esq.
Hearings Officer

Dated in Boston this 17th day of January, 1984.

This decision was unanimously approved by the Energy Facilities Siting Council at its meeting on January 17, 1984, by those members present and voted.

Voting in favor: Ms. Sharon Pollard, Chairperson; Ms. Sarah Wald, for the Secretary of Consumer Affairs; Mr. Walter Headley, for the Secretary of Environmental Affairs; Ms. Joellen D'Esti, for the Secretary of Economic and Manpower Affairs; and Mr. Thomas J. Crowley, Public Member, Engineering.

January 18, 1984
Date

Sharon M. Pollard
Sharon Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Algonquin, SNG, Inc. for Approval of the Second Supplement to its Second Long-Range Forecast	EFSC No. 83-34

FINAL DECISION

Douglas I. Greenhaus, Esq.
Hearings Officer

Introduction

Algonquin SNG, Inc. (hereinafter "the Company" or "Algonquin") is a "gas company" as defined under the regulations of the Massachusetts Energy Facilities Siting Council (hereinafter "the Council" or "the EFSC"). Rule 3.3, 980 CMR 2.03. Pursuant to the provisions of Mass. G.L. c. 164, sec. 69I and in accordance with Administrative Bulletin EFSC No. 80.2, the Company filed its Second Supplement to its Second Long-Range Forecast with the Council on September 9, 1983.

Summary of the Proceedings

The Company was ordered to post Notice of Adjudicatory Proceeding on September 12, 1983. No persons requested to intervene or otherwise participate in the proceeding by the October 6, 1983 due date. On October 21, 1983, the Hearings Officer issued a set of Document and Information Requests. Responses were received from the Company on November 16, 1983.

Review of the Supplement

A. Description of the Facility and Gas Production

Algonquin SNG, Inc., owns and operates a single synthesized natural gas ("SNG") facility which is located in Freetown, Massachusetts. SNG is manufactured at the facility using naptha, a petroleum derivative, as a feedstock. The fuel used for plant operation derives from the SNG being produced at the facility. In addition, pipeline gas is used for start up purposes. For example, from October 1982 through August 1983 a total of 42.575 BBtu of such gas was consumed by the plant. See, Information Request S-1.

The Algonquin SNG facility continues to demonstrate 100% reliability (expressed a a percentage of gas produced during a season relative to requested customer quantities). 1983 Forecast Supplement sec. III, p.6. In large part this high degree of reliability is due to the 100% reliability of Algonquin's naptha supplier. For December, January and February of 1983-84, Algonquin has scheduled 1,288,690 bbl of naptha for delivery. There are two 266,000 bbl naptha storage tanks located at the Freetown site. Should there ever be a failure in the delivery of napththa supply, the supplier and/or Algonquin would look to other potential naphtha suppliers including the spot market.

The facility consumes approximately ten gallons of naphtha in order to produce 1 MMBtu of SNG. The 1983-84 scheduled delivery of 1,288,690 bbl (54,124,980 gals.) of naphtha will more than suffice to provide the 5,153.606 BBtu's of SNG requested by SNG customers in 1983-84.

B. The SNG-1 Tariff

The Company continues to manufacture, deliver and sell its entire production to the Algonquin Gas Transmission Company ("AGT") in order to help supply the winter requirements of gas distribution customers both within and without the Commonwealth of Massachusetts. Over the years, as gas supplies available to meet winter requirements became more abundant and as the price of SNG escalated, the customers of AGT have negotiated expanded flexibility provisions into their contracts.

In June of 1983, the Federal Energy Regulatory Commission ("FERC") approved a revised Rate Schedule SNG-1. The Rate Schedule establishes a "Basic Delivery Schedule" for each delivery season during the remaining tem of the SNG contract.[1] Additional Supplemental Delivery Schedule one-year quantities may be nominated by June 20 of each year for the upcoming winter season. In addition, customers may request SNG Spot Deliveries during the heating season. The availability of Supplemental and Spot Deliveries are subject to Algonquin's ability to obtain additional naphtha quantities.

The SNG-1 customers within Massachusetts have requested a total Basic Delivery Schedule of 2,677,828 MMBtu for 1983. The following table shows the SNG-1 Basic Delivery Schedule for 1983-84 for each of the Massachusetts SNG-1 customers. No Supplemental Delivery quantities have been requested for the 1983-84 season.

TABLE I

Company	Seasonal Contract Demand (MMBtu)	1982-83 Nominated Quantity (MMBtu)	1983-84 Basic Delivery Schedule Quantity (MMBtu)
1. Bay State Gas Co.	2,766,169	1,383,093	0
2. Boston Gas Co.	1,844,012	651,524	378,572
3. Colonial Gas Co.	614,721	307,362	309,396
4. Commonwealth Gas Co.	3,304,031	2,711,007	1,684,860
5. Fall River Gas Co.	1,075,724	562,855	305,000
6. Town of Middleborough	30,804	17,861	0
7. N. Attleboro Gas Co.	15,402	9,000	0
TOTAL	9,650,863	5,642,792	2,677,828

1. The current contract extends until October 1, 1987. Customers wishing to terminate their SNG-1 contract must provide twelve months notice. Thus, customers may terminate their SNG-1 contract if they give proper notice in AGTC by October 1, 1986.

Four of the Commonwealth's gas companies continue to request quantities of SNG for the duration of the contract period in order to meet their sendout requirements. The following table indicates these requested amounts and compares them to last year's nominated quantities.

TABLE II

Company	Peak Day/Contract Demand (MMBtu)	1982-83 Peak Day Nominated Quantity (MMBtu)	SNG-1 Peak Day Quantity Requested Commencing 1983-84 (MMBtu)
1. Bay State Gas Company	18,319	14,438	0
2. Boston Gas Co.	12,212	12,212	12,212
3. Colonial Gas Co.	4,071	3,056	4,071
4. Commonwealth Gas Co.	21,881	21,881	21,881
5. Fall River Gas Company	7,124	4,500	4,500
6. Town of Middleborough	204	204	0
7. N. Attleboro Gas Co.	102	102	0
TOTAL	63,913	56,393	42,664

Notably the Boston Gas Company, the Colonial Gas Company, the Commonwealth Gas Company and the Fall River Gas Company continue to require SNG in order to meet their sendout requirements. The Council is particularly encouraged by Algonquin's attempts at modifying the rate schedule so as to accomodate the continuing needs of these companies. With the creation of the three tier ordering system, a customer company now has more flexibility to provide gas to its own customers during the heating season at the least possible cost.

DECISION AND ORDER

The Council hereby unconditionally APPROVES the Second Supplement to the Second Long-Range Forecast of the Algonquin SNG, Inc. The Third Supplement will be due no later than July, 1, 1984.

Energy Facilities Siting Council

Douglas Greenhaus

Douglas I. Greenhaus, Esq.
Hearings Officer

Dated at Boston this 17th day of January, 1984.

This decision was unanimously approved by the Energy Facilities Siting Council at its meeting on January 17, 1984, by those members present and voted.

Voting in favor: Ms. Sharon Pollard, Chairperson; Ms. Sarah Wald, for the Secretary of Consumer Affairs; Mr. Walter Headley, for the Secretary of Environmental Affairs; Ms. Joellen D'Esti, for the Secretary of Economic and Manpower Affairs; and Mr. Thomas J. Crowley, Public Member, Engineering.

1/25/84
Date

Sharon M. Pollard
Sharon Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

North Attleboro Gas Company — EFSC Docket No. 81-22

FINAL DECISION

James G. White, Jr.
Hearing Offficer

January 17, 1984

The Energy Facilities Siting Council ("Siting Council") APPROVES SUBJECT TO CONDITIONS, the combined Second Long-Term Forecast and First Supplement of natural gas requirements and resources ("Forecast") of North Attleboro Gas Company ("North Attleboro").

I. Background, History of the Proceedings, Standard of Review

North Attleboro serves approximately 2200 residential customers and approximately 290 industrial and commercial customers in North Attleboro and Plainville, Massachusetts. North Attleboro's historical total firm annual sendout has been in the range of 200 to 230 MMcf, which represents approximately one hundredth of one percent of total firm natural gas sales in the Commonwealth. Approximately two-thirds of North Attleboro's sales are to residential customers. North Attleboro makes no interruptible sales or sales for resale.

North Attleboro filed its Second Long-Range Forecast on December 7, 1981.[1] North Attleboro was not contacted by the Siting Council until February 9, 1983. Thereafter North Attleboro provided public notice of the Forecast by posting and publication. On July 11, 1983, the Hearing Officer met with North Attleboro at the Company's offices to discuss a set of information requests sent to North Attleboro on June 24, 1983. North Attleboro's responses to the information requests, including certain updated Tables, were received on October 27, 1983.[2]

The Siting Council recognizes that the appropriateness of a gas company's forecasting methodology must be considered against the size and resources of the Company and the factual circumstances in the particular service territory. Blackstone Gas Company, 8 DOMSC 34, 35 (1982).[3]

II. Sendout Requirements

North Attleboro basically employs judgement based on historical data and an intimate knowledge of the Company's operations and service territory to forecast its future sendout requirements. For the first time, North Attleboro also developed monthly sendout duration curves and

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1. North Attleboro Gas Company's Fourth Annual Supplement to its First Long-Range Forecast was rejected summarily. N. Attleboro Gas Co., 6 DOMSC 95 (1981).
2. By verbal agreement of the Hearing Officer and North Attleboro's President, Mr. Jay Underhill, North Attleboro agreed to update the Forecast. The update comprised the First Supplement. The Hearing Officer and Mr. Underhill agreed that the Forecast as updated would satisfy North Attleboro's filing requirements until a review was completed. The Hearing Officer and Mr. Underhill agreed the decision in this proceeding would provide the deadline for the next Supplement.
3. The Energy Facilities Siting Council employs a three-pronged test in evaluating gas forecasts. A forecast is reviewable if it contains enough information to allow a full understanding of the methodology. A methodology is appropriate if it is technically suitable for the particular company. A forecast is reliable if it engenders confidence as an accurate predictor of future events. Haverhill Gas Co., 8 DOMSC 48, 50 (1982).

determined base unit and heating unit loads.[4] This analysis allowed North Attleboro to determine "acceptable standards for future usage."[5] Due to limited distribution capacity and limited economical winter supplies, North Attleboro has adopted a no growth policy, and projects a one percent "annual creep" in unit base and heating loads. North Attleboro also projects an annual increase of ten residential customers, and one commercial or industrial customer per year.[6]

North Attleboro's normal year sendout requirements are based on weather data for the period 1971-80. North Attleboro defined its design year as one which is ten percent above normal. The peak day is the actual peak in the same ten year period.

The Siting Council recognizes that North Attleboro's Forecast is superior to any filing previously submitted by the Company. Nevertheless, there is still substantial room for improvement. First, the narrative explaining the methodology is very brief and almost renders the Forecast unreviewable. Secondly, the updated submission on October 27, 1983, contains data which is inconsistent with data previously submitted.[7] Third, sendout requirements should be based on updated weather data. Accordingly, the Siting Council will require North Attleboro to meet with the Siting Council Staff within 90 days to address these deficiencies.

III. Supply Sources and Facilities

North Attleboro receives pipeline gas from Algonquin Gas Transmission Company ("Algonquin") under three separate contracts. The contract dated September 15, 1969, provides for a firm maximum annual quantity of 219.7 MMcf and a firm maximum daily quantity of 814 Mcf to be provided to North Attleboro under Algonquin's F-1 Rate Schedule.[8] Similarly, the contract dated October 31, 1969, provides for a firm winter contract quantity of 16.1 MMcf, and a firm maximum daily contract

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4. The Siting Council's last decision involving North Attleboro contained eight conditions. See N. Attleboro Gas Co., 6 DOMSC 95, 100-101 (1981). North Attleboro's current Forecast satisfies those conditions.
5. Response to Information Request No. 11 dated October 27, 1983.
6. North Attleboro's data submitted on October 27, 1983, combines residential heating and non-heating customers due to a change in rate classifications. Previously, these categories were separated.
7. The Forecast submitted in December 1981 predicts peak day requirements rising to 1976 Mcf in the 1985-86 split year. The update comprising the First Supplement, however, reflects much lower peak day requirements in the range of 1390 to 1600 Mcf in the forecast peiod. Notably, North Attleboro's Return to the Department of Public Utilities for 1981 indicates a peak sendout on January 11, 1981 of 1737 Mcf.
8. The supplies indicated in this Section are expressed in volumetric terms at 1000 Btu per Mcf.

quantity of 268 Mcf under Algonquin's WS-1 Rate Schedule.[9] The F-1 and WS-1 contracts expire in 1989 but both will continue in effect thereafter until cancelled on 12 months written notice by either party. North Attleboro also receives supplies of storage gas from Algonquin on a best efforts basis under a contract dated September 15, 1980. The service is provided under Algonquin's Rate Schedule STB. Under the STB contract, North Attleboro has an annual storage capacity of 109.9 MMcf. The maximum daily delivery is 94 Mcf.

North Attleboro also has a 1977 contract with Algonquin for the purchase of supplies of synthetic natural gas. North Attleboro, however, has opted to receive no SNG from Algonquin through 1987, which is the initial expiration date under the contract.

North Attleboro also purchases gas from Bay State Gas Company.[10] The current contract was executed on September 29, 1983 and provides for the following quantities of gas in MMBtu's for the winter periods from 1983-84 through 1987-88. Thereafter the contract will continue in effect until cancelled by 12 months notice of either party.

	Firm	Optional	Total
December	1,200	1,300	2,500
January	5,800	1,600	7,400
February	2,000	100	2,100
Total	9,000	3,000	12,000

Under the contract, North Attleboro is required to use its best efforts to receive the gas by displacement at the interconnection between the two parties on North Avenue in North Attleboro. This gas is delivered after North Attleboro's advance verbal request one hour prior to delivery. The maximum hourly rate for delivery of gas by displacement is 60 MMBtu. If deliveries cannot be accomplished by displacement, North Attleboro can elect to receive up to two truckloads of propane per day.

North Attleboro has storage capacity for 51,000 gallons of propane, or 4.64 MMcf, and a maximum daily design sendout of propane-air of 960 Mcf.[11] North Attleboro has abandoned the use of its wet seal holder which provided storage in the amount of 200 Mcf.

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9. The winter contract period extends from November 16 through April 15 of the following year.
10. The Bay State contract has not yet been approved by the Department of Public Utilities. The firm quantities are purchased by North Attleboro on a take or pay basis. The new contract supersedes the previous contract dated October 25, 1978, which itself was amended on June 23, 1980, July 1, 1981, and August 23, 1982 to provide for increased firm and optional quantities of gas.
11. In the split years 1980-81 and 1982-83, the total annual propane senodut were 9779 Mcf and 1226 Mcf respectively. For the same split years, the peak day propane sendouts were 365 Mcf and 202 Mcf.

North Attleboro purchases propane under an open contract from Delaware Valley Propane Company in Pawtucket, Rhode Island.[12]

IV. Comparison of Requirements and Resources

The Siting Council is particularly concerned with the ability of gas companies to meet design year, peak day and cold snap requirements. The following table indicates the supplies available to North Attleboro to meet projected design heating season sendout requirements through the 1986-87 winter.

Design Heating Season (MMcf)

	83-84	84-85	85-86	86-87
Firm Requirements	165.5	166.9	167.3	168.4
F-1	122.9	122.9	122.9	122.9
WS-1	16.1	16.1	16.1	16.1
SNG	0	0	0	0
Bay State	12.0	12.0	12.0	12.0
Propane	14.5	15.9	16.3	17.4

The quantities of F-1, WS-1, and Bay State gas reflect maximum contract quantities. The propane quantities comprise the difference between the projected firm sendout requirements and firm Algonquin and Bay State contract quantities. As noted previously, North Attleboro also receives storage return gas from Algonquin on a best-efforts basis. Thus, North Attleboro clearly has access to sufficient quantities of gas to meet design year requirements.

North Attleboro also has sufficient supplies to meet peak day and cold snap requirements. North Attleboro can receive a daily total of 1082 Mcf from Algonquin under Rate Schedules F-1, and WS-1. Additionally, North Attleboro can vaporize 960 Mcf of propane per day, and can receive up to 60 MMBtu per hour from Bay State. Although, North Attleboro's Forecast contains inconsistent projections of peak day requirements, the foregoing supplies are sufficient to meet the highest peak day, 1976 Mcf, forecasted by North Attleboro. North Attleboro would utilize the same array of supplies to meet a cold snap of weather at prolonged near-peak conditions. Assuming full storage quantities of propane, North Attleboro could vaporize 960 Mcf per day of propane for nearly five days, without replenishing storage. And as stated above, North Attleboro can receive up to 60 MMBtu per hour from Bay State, and also may receive storage gas on a best efforts basis.

Again, North Attleboro's Forecast could be improved by expanding the narrative portion of the Forecast on gas supply. Additionally, the Siting Council believes that future filings would be enhanced by a

12. In the past, North Attleboro also has elected to receive small quantities of propane from Bay State under the election provision of the contract.

comparison of requirements and resources shown on Table G-22, and a narrative plan for meeting peak day and cold snap requirements. The Siting Council also observes that the Forecast contains no reference to North Attleboro's prospective repurchase of CONTEAL volumes from Algonquin. Although North Attleboro's present supply appears sufficient to meet projected requirements, the CONTEAL volumes should be included in the Forecast. Siting Council Staff is available at any time to provide assistance.

V. Order

The Siting Council approves North Attleboro's combined Second Long-Term Forecast and First Supplement subject to the following conditions.

1. North Attleboro will meet with the Siting Council Staff within 90 days to discuss deficiencies in the forecast methodology discussed herein. North Attleboro will comply with any directives of the Hearing Officer assigned to North Attleboro's next submission in Docket No. 84-22 which result from that meeting.

2. North Attleboro will file its next Supplement on July 1, 1984.

3. The Supplement due on July 1, 1984, shall contain Table G-22, descriptions of North Attleboro's plans for meeting peak day and cold snap requirements, and a description of the terms of purchase of CONTEAL volumes from Algonquin and the impact of this purchase in North Attleboro's supply plan beginning in the 1984-85 split year.

James G. White, Jr.
James G. White, Jr.
Hearing Officer

January 17, 1984

This Decision was approved by unanimous vote of the Energy Facilities Siting Council at its meeting on January 17, 1984, by those members and representatives present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paula Gold, Secretary of Consumer Affairs); Walter Headley (for James S. Hoyte, Secretary of Environmental Affairs); Joellen M. D'Esti (for Evelyn F. Murphy, Secretary of Economic Affairs); Thomas Crowley, Public Engineering Member.

January 31, 1984
Date

Sharon M. Pollard
Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Fall River Gas Company for Approval of the Combined First and Second Supplements to its Second Long-Range Forecast of Gas Requirements and Resources	)	Docket No. 83-20

FINAL DECISION

James G. White, Jr.
Hearing Officer

On the Decision:
George Aronson, Director of Technical Analysis
Margaret Keane, Gas Analyst

The Energy Facilities Siting Council ("Siting Council") hereby APPROVES subject to CONDITIONS the Combined First and Second Supplements ("Supplement") to the Second Long-Range Forecast of natural gas requirements and resources for the years 1983 through 1988 of the Fall River Gas Company ("Fall River" or "the Company").[1]

I. Background

Fall River distributes and sells natural gas to approximately 41,000 customers in the City of Fall River and the Towns of Somerset, Swansea, and Westport. Total firm sendout in the 1982-83 split year was 5025 MMcf, which made Fall River the fifth largest gas distribution utility in Massachusetts. Approximately two-thirds of the Company's firm sendout goes to residential heating customers, 22% to industrial customers, 8% to commercial customers, and 2% to residential non-heating customers. Between 1978 and 1982, Fall River increased its firm sendout by 7.8% and increased its number of firm customers by 4.4%. In this Supplement, Fall River projects that its number of firm customers will increase by 1.4% over the forecast period, and that its total firm sendout will decline by 3.2%.

II. History of Proceedings

Fall River filed the current Supplement on August 16, 1983.[2] Fall River provided notice of this proceeding to the public by publication and posting in accordance with the directions of the Hearing Officer. The Siting Council received no intervention petitions. Fall River submitted complete and timely responses to two sets of Information Requests of the Siting Council Staff.

III. Compliance with Conditions

The Siting Council's decision on Fall River's Second Long-Range Forecast contained three conditions. Fall River Gas Company, 8 DOMSC 238, 255-56 (1982). The first condition required Fall River to include in its next filing analyses of the anticipated effects on sendout projections of decontrol of natural gas prices, anticipated marketing strategies for insuring reliable and economical gas supplies, and anticipated problems with collection of customer accounts. The second condition required Fall River to meet with the Siting Council Staff to discuss development of a methodology for projecting customer use factors, and peak day and design year requirements. Pursuant to the second condition, the Siting Council Staff met with Fall River on July

1. Condition three to the decision of the Energy Facilities Siting Council on Fall River Gas Company's ("Fall River") Second Long-Range Forecast required Fall River to file a Combined First and Second Supplement. Fall River Gas Co., 8 DOMSC 238, 256 (1982).
2. By letter dated February 25, 1983, the Hearing Officer granted Fall River an extension until July 1, 1983 for submission of the combined First and Second Supplement. The Siting Council Staff and Fall River, however, did not meet until July 13, 1983, and the deadline was extended.

13, 1983 to discuss development of Fall River's sendout methodology. The results of the meeting and Fall River's response to the first condition are discussed in the Sendout section. The third condition in the Siting Council's last decision concerned the filing date for the Supplement under current review discussed in footnote 2, supra.

IV. Forecast of Sendout Requirements

A. Description of Forecast Methodology

Fall River bases the projections in its Supplement on historical sales, sendout and weather data, as well as management judgements and knowledge of its service territroy. Fall River forecasts firm seasonal sendout separately for the residential heating, residential non-heating, commercial and industrial classes for each heating and non-heating season over the forecast period, then sums across classes to calculate total firm sendout. The Company uses the following formula:

$$\begin{array}{c}\text{Seasonal}\\ \text{Sendout}\\ \text{By Class}\\ \text{(MMcf)}\end{array} = \begin{array}{c}\text{Base Use}\\ \text{per customer}\\ \text{per year}\end{array} \times \frac{MPS}{12} \times \begin{array}{c}\text{Number of}\\ \text{customers}\\ \text{in class}\end{array} + \begin{array}{c}\text{Heating Use}\\ \text{per customer}\\ \text{per DD}\end{array} \times \begin{array}{c}\text{DD per}\\ \text{season}\end{array} \times \begin{array}{c}\text{Number of}\\ \text{customers}\\ \text{in class}\end{array}$$

where MPS = Months per season
(5 for the heating season,
7 for the non-heating season);
DD = Heating degree-days per season.

Fall River derives its projections of base use per customer per year ("base factors") and heating use per customer per degree day ("heating factors") for each customer class from "company monthly gas operating statistics and sales statistics" and from Company expectations regarding conservation.[3] Fall River uses the same base and heating factors to project both normal and design year sendout.

For the residential heating class, Fall River expects the base factor to decline by 2.6% and 1.9% in the 1983-84 and 1984-85 split years. Fall River also projects a one percent heating factor decline in each of the same two split years. The rates of decline are expected to slow down in the later years of the forecast period as residential customers complete "the easy and least expensive conservation measures."[4] For the other customer classes, Fall River forecasts that the base and heating factors will stay approximately constant over the forecast period, with declines in consumption of 1-2% per year due to conservation. Fall River states that these conservation rates are comparable to national estimates supported by studies performed by the American Gas Association.[5]

Fall River estimates the number of customers separately for each customer class. For the residential heating class, Fall River projects the addition of 200 customers per year (about 100-110 from new services,

3. Supplement at 2.
4. Response to Information Request SO-8 dated November 28, 1983.
5. See Supplement at 6, 8; Response to Information Request SO-5 dated November 28, 1983.

and about 80 conversions from existing non heat residential customers). The number of residential non-heating customers declines over the forecast period because of conversions to gas heat. The Company projects the addition of 25 commercial customers and one industrial customer per year based on five years of historical data and consultation with the Industrial and Commercial Development Agent for the city of Fall River.[6]

Fall River uses seasonal degree-day totals for normal and design years based on actual degree-day totals for 1971-1981. The Company's normal year contains 6000 degree-days (1345 in the non-heating season and 4655 in the heating season) based on the arithmetic average of the degree-day totals in each of those ten years. The Company's design year contains 6500 degree-days (1400 in the non-heating season and 5100 in the heating season), which is just slightly more than actually occurred in 1980-81 (6494 degree-days).

Table 1 shows Fall River's forecast of firm sendout by customer class for a normal year, and total firm sendout for a design year, for the first and last years of the forecast period.

TABLE 1
Forecast of Firm Seasonal Sendout
(MMcf Per Season)

	1983-84		1987-88	
	Non-heating Season	Heating Season	Non-heating Season	Heating Season
RESIDENTIAL				
Heating	1043.1	2226.6	1027.7	2217.2
Non-heating	52.6	49.0	49.7	46.2
COMMERCIAL	128.3	279.4	123.7	273.7
INDUSTRIAL	534.6	575.1	528.2	569.9
COMPANY USE AND UNACCOUNTED	(25.0)	250.0	(25.0)	205.0
NORMAL YEAR TOTAL FIRM SENDOUT	1733.6	3380.1	1704.3	3312.0
DESIGN YEAR TOTAL FIRM SENDOUT	1776.3	3593.0	1746.3	3524.0

Fall River forecasts peak day sendout on the basis of historical sendout data for its entire system (as opposed to billing or sales data, which can be disaggregated by customer class). The Company determines its daily base load from actual sendout data (not including interruptible sales) from the non-heating month of August. The daily base load

6. Response to Information Request No. SO-5 dated November 28, 1983.

figure is projected forward through consideration of the impacts of new customer additions and of conservation. Heating factors are determined from the historical relationship between sendout and degree-days (monitored daily during the heating season), again projected forward to account for anticipated customer additions and conservation. The Company uses a peak day total of 74 degree-days based on an actual recorded value of 69 degree-days for 1980-81 and a 5 degree-day margin to account for day of the week, wind chill, and other factors. The 74 degree-day standard replaces the Company's previous standard of 70 degree-days on a peak day, pursuant to the discussion with the Siting Council Staff in response to the second condition to our last Decision. The 74 degree days are multiplied by the heating factor and added to the base factor to determine the projected peak day requirements.

Table 2 shows Fall River's projections of peak day sendout over the forecast period, as well as the base and heating factors used to produce the projections.

TABLE 2

Forecast of Peak Day Sendout
(MMcf)

Year	Peak Day Sendout	Base Factor	Heating Factor (MMcf/DD)
1983-84	46.000	9.000	0.500
1984-85	46.688	8.800	0.512
1985-86	46.832	8.500	0.518
1986-87	46.954	8.400	0.521
1987-88	47.150	8.300	0.525

B. Analysis of Forecast Methodology

The structure of Fall River's forecasting approach is basically sound. The Siting Council has previously found that the use of base and heating factors to forecast sendout is appropriate for gas utilities of modest size and resources. The Council has also recognized the importance of judgement, experience, and familiarity with the service territory in producing a reliable forecast. To the extent that Fall River's forecast is based on the use of base and heating factors as modified by judgement, the forecast methodology can be considered appropriate for a company of Fall River's size.

In the current Supplement, however, Fall River has not described clearly the calculation of its base and heating factors, nor described how it uses judgement to interpret historical data. These omissions preclude the Siting Council from viewing the projections in the Supplement with total confidence.[7] The statutory mandate for forecast review requires the Siting Council to insure that "all information

7. The Siting Council views a forecast to be reliable if the methodology engenders confidence in the results as an accurate prediction of future events. N. Attleboro Gas Co., Docket No. 81-22 (January 17, 1984).

relating to current activities...is substantially accurate and complete," and that the forecast is "based on substantially accurate historical information and reasonable statistical projection methods...." Mass. Gen. Laws Ann. Chapter 164, Section 69J. The text of Fall River's Supplement, and the answers to information requests contain too many omissions and internal inconsistencies for the Siting Council to rule unconditionally that these standards have been met.

The Company does not specify clearly which data have been used to produce the Supplement. For example, Tables G-1 and G-2 of the Supplement show the addition of 200 new residential heating customers per year, and the loss (presumably through conversion to gas heat) of 50 residential non-heating customers per year, which implies that 150 (=200-50) new residential heating services are being added each year. In contrast, the Company's response to Information Request SO-1 states that the Company can expect to add 100-110 new services per year, and to convert 80 existing customers per year. These statements conflict, but the Company does not present evidence that resolves the contradictions. Similarly, conflicting statements appear in the Supplement concerning the calculation of base load and heating load factors, but the Company neither provides the historical values of the variables in question nor describes explicitly how these variables were analyzed to produce those finally used in the Supplement.

Likewise, the Company does not specify how it uses judgement to interpret historical data. For example, regarding its forecast of peak day sendout, Fall River first states that "we took into consideration...any evidence of conservation which at this point is estimated to be about 2% per year for the last four years" (Supplement at 6), and then states that "we feel conservation on peak days to be non-existent" (Supplement at 8). Fall River also states that usage per degree-day declines as the number of degree days increases. (Supplement at 3). None of the impacts of these judgements have been quantified in the discussion of its peak day forecast, nor has the Company supplied historical back-up data to support its judgements.

Further, the Company does not supply the statistical basis for its design year degree-day standard. The Company states that "[t]aking into consideration that the 1980-1981 season was the coldest in weather records, we feel 6500 degree-days is still a reasonable design year" (Supplement at 5). However, the 1976-77 heating season contained 5110 degree-days, ten more than the 5100 degree-day standard for the heating season. Likewise, the 1978-79 non-heating season contained 1543 degree-days, substantially more than the 1400 degree-day design year standard for the non-heating season. Given that the Company has actually experienced weather conditions in the last ten years that exceed its design standards, the Siting Council would expect the Company to analyze the adequacy of its standard in more rigorous quantitative terms than have been presented here.

These problems are not insoluble. As mentioned earlier, the Company's forecasting approach is basically sound. Moreover, the Company has been responsive to some of the Council's concerns, as evidenced by its prompt and detailed answers to information requests concerning its resources and supplies. The need remains, however, for a systematic and complete method for explaining and documenting the forecast methodology such that the Siting Council can reproduce the results and resolve any apparent inconsistencies. The narrative description of the forecast should be expanded, and the documentation should include, but not be limited to:

- a complete set of the historical data which form the basis for important forecast parameters;
- summary statistics for the historical data, such as arithmetic averages, standard deviations, or regression results;
- statements that specify assumptions for extending the historical data through the forecast period (e.g., does a historical trend continue? Does a parameter that has varied randomly about a historical mean remain constant? Do use factors decline because of conservation? Will trends change because of gas decontrol?)
- statements that specify outside sources or studies that were used to confirm these assumptions (e.g., AGA studies, contact with local economic development officials).

The Siting Council hereby ORDERS the Fall River Gas Company to provide the Council with a compliance plan within ninety days that presents a systematic and complete method to document the Company's forecast methodology in concert with the guidelines provided herein. The Company shall meet with Council Staff within thirty days to discuss preparation of a compliance plan to satisfy this Condition, affixed hereto as Condition 1.

In addition to the general concerns expressed above, the Siting Council retains its concerns for one specific aspect of the Company's Supplement - the basis for its design year degree-day standard. We are concerned both because of the lack of a statistical basis for the standards (because the Company has experienced actual seasons with degree-day levels that exceed its design standards, as explained above), and because the Company's design year standard exceeds its normal year standard by the smallest margin of any gas utility in the Commonwealth. Thus, the Council hereby ORDERS the Fall River Gas Company to provide in its next Supplement statistical justification for its design weather degree-day standards. The justification shall include, but shall not be limited to, historical degree-day data for past heating and non-heating seasons; summary statistics for these data by season and by year; and an evaluation of the probability based on historical data that the Company's design standards will be exceeded on a seasonal or yearly basis. The Council Staff is available to assist the Company with the analysis required by this Condition, affixed hereto as Condition 2.

V. Supply Contracts and Facilities

A. Pipeline Supplies

Fall River has four gas supply Agreements with Algonquin Gas Transmission Company (Algonquin). Fall River and Algonquin are parties to a 1969 contract which provides for firm deliveries of natural gas under Algonquin F-1 Rate Schedule up to a maximum daily quantity of 14.6 MMcf and maximum annual quantity of 3958 MMcf.[8]

Fall River's August 22, 1968, Agreement with Algonquin provides for firm deliveries of winter service gas under Algonquin's WS-1 Rate Schedule. The winter contract quantity is 429 MMcf and the maximum daily quantity is 7.1 MMcf.[9]

Fall River purchases synthetic natural gas (SNG) under an Agreement dated July 14, 1977. Fall River has backed off on its purchases under the SNG contract, and projects purchasing the minimum of 303 MMcf per year until the Agreement expires on September 30, 1987. The maximum daily quantity under the reduced contract is 4.5 MMcf.

Finally, Algonquin provides storage service and transportation to Fall River under Rate Schedule STB as provided by the Agreement dated September 8, 1981.[10] The total storage capacity is 180 MMcf, and the firm daily delivery quantity is 1.87 MMcf.[11]

B. Liquefied Natural Gas

Fall River purchases gas from Bay State Gas Company (Bay State) under an Agreement dated September 24, 1982.[12] The Agreement provides for purchase of the following quantities (MMBtu):

TABLE 3

	Split Years 1983-84 to 1986-87			Split Year 1987-88		
	Firm	Optional	Total	Firm	Optional	Total
April-October	0	0	0	0	0	0
November	25	0	25	100	15	115
December	25	0	25	125	30	155
January	71	29	100	221	99	320
February	71	29	100	196	74	270
March	71	29	100	146	44	190
Total	263	87	350	788	262	1050

8. The October 30, 1969, Service Agreement for F-1 deliveries has an original termination date of November 1, 1989, and provides for possible yearly extensions thereafter. This Agreement provides for delivery points in Fall River and in Westport.
9. The winter service period under the contract runs from November 16 through April 15. The gas is delivered at a meter station in Fall River. The maximum deliverable daily quantity under Rate Schedule WS-1 actually varies according to the percentage of the winter contract quantity that has been delivered. Until 80 percent of the winter contract quantity has been delivered, the maximum daily quantity is 7.1 MMcf.
10. The Agreement has an initial expiration date of April 15, 2000. Again, the gas is delivered in an interconnection in Fall River, Massachusetts.
11. The daily storage demand is 2.0 MMcf. The difference between the daily storage quantity and the firm deliverable portion is .13 MMcf which represent fuel charges.
12. The Agreement contains an initial expiration date of March 31, 1988, but will continue on a contract-year basis thereafter until cancelled on twelve months notice of either party.

Fall River can elect to purchase a portion or all of the optional quantities on written ten-days notice prior to the month of deliveries. There is no existing interconnection between Fall River and Bay State. Thus, all deliveries are accomplished by trucking which is the responsibility of Fall River. Fall River, however, has the option to take delivery in the form of propane. The Agreement with Bay State does not limit the number of daily truckloads. Rather, the Agreement limits only the monthly volumes available to Fall River as indicated above.

Fall River purchases 435 MMcf of imported Algerian LNG from Distrigas of Massachusetts Corporation (DOMAC) under a contract that extends until the year 2000. The terms of the contract require Fall River to take half of its tender within ten days of unloading of the LNG ship and the remaining half one-day prior to arrival of the next ship. Fall River uses its own two LNG trucks to transport DOMAC LNG. A truckload is comprised of approximately .86 MMcf, thus requiring approximately 38 truckloads of LNG for each ship of LNG from Algeria.[13] Under its current Service Agreement with DOMAC, Fall River may receive two truckloads per day.

Fall River has two LNG vaporizers with a combined design daily vaporization capacity of 20 MMcf, and one LNG storage tank with a capacity of 45,000 barrels, or 157 MMcf.

C. Propane

As indicated in the last Decision, Fall River is party to a firm contract with Petrolane Northeast Gas Service (Petrolane) for the purchase of the equivalent of 275 MMcf per year through the 1984-85 heating season. Under the contract, twenty-five percent of the propane must be purchased in the non-heating season. Fall River can request delivery of truckloads (8,500 gallons; 7.8 MMcf) on 48 hours advance notice to Petrolane.[14]

The contract with Petrolane contains an initial expiration date of March 31, 1985. The contract, however, also contains an option exercisable by April 1, 1984 to extend the contract for an additional five years, and provides that after March 31, 1985, the contract shall continue on a contract year basis unless cancelled on twelve months notice.

Fall River's Supplement indicates a reduced reliance on propane through 1985 and non-reliance on propane on a seasonal basis upon the expiration of the Petrolane contract. The Siting Council is concerned

13. Response to Information Request S-11 dated February 4, 1984.
14. The current propane contract contains a schedule for monthly deliveries. There is no provision for deliveries in the months of June, July and August. The schedule calls for deliveries totaling 45.4 MMcf for each January and February, 44 MMcf in March, and 33 to 36 MMcf in each of October, November and December. The Schedule for April, May, and September calls for 13.7, 8.25 and 13.2 MMcf, respectively.

about long-term renewal of propane contracts when other alternatives such as Canadian supplies, alternative pipeline supplies, or shorter term propane contracts might provide greater flexibility. Fall River has indicated the propane contract will be renegotiated probably with lesser volumes and more options than the current Petrolane contract.[15] Fall River is encouraged to continue to examine closely its plans for future propane supplies in light of alternatives and projected cold snap requirements and should be prepared to justify its decision to the Siting Council.

As indicated in the Siting Council's last Decision, Fall River has four 80,000 gallon and five 30,000 gallon propane tanks for a total storage capacity of 37 MMcf. Fall River has two propane-air vaporizers (one high pressure, the other low pressure) with a combined daily vaporization capacity of 12 MMcf.

D. Alternative Domestic Pipeline Supplies

Fall River's Table G-22 containing the comparison of requirements and resources did not reflect the future purchase of any new pipeline supplies. In the discovery process, however, Fall River stated that it expected to purchase 1 MMcf per day on a firm basis under the CONTEAL proposal pending before the Federal Energy Regulatory Commission. Fall River projected the price of the supplies to be in the range of $5.50 per MMBtu. And, Fall River indicated that commencement of these deliveries at a time which nearly coincides with the expiration of the Petrolane propane contract "should eliminate the propane contract" and possibly allow a cutback in the Bay State LNG contract. More recently, Fall River has indicated that it has no current plans to purchase CONTEAL volumes.[16] The Siting Council requests Fall River to include in its next Supplement any new pipeline supplies, and reflect the impact throughout the Supplement including the peak day and cold snap projections.

V. Comparison of Requirements and Resources

A. Normal Year

In a normal weather year, Fall River must have adequate supplies to meet several types of requirements. Most importantly, Fall River must meet the requirements of its firm customers. Secondly, Fall River must fill the available underground storage prior to the start of the heating season. Third, Fall River must replenish LNG storage during both heating and non-heating seasons as supplies are sent out. To the extent possible, Fall River also supplies gas to its interruptible customers.

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15. Response to Information Request S-14 dated February 14, 1984.
16. Response to Information Request S-3(b) dated November 28, 1983; Response to Information Request S-13 dated February 14, 1984.

TABLE 4

Normal Heating Season

(MMcf)

Requirements	83-84	84-85	85-86	86-87	87-88
Normal Requirements	3380.1	3347	3328	3311	3312
Interruptible Sales	124	126	70	87	140
	3504	3473	3398	3398	3452
Resources					
F-1	2040	2040	2040	2040	2040
ST-1	180	150	150	150	150
WS-1	357	357	357	357	357
SNG-1	303	303	303	303	-
LPA (take)	76	75	-	-	-
LNG (take)	498	498	498	498	855
(storage)	50	50	50	50	50
	3504	3473	3398	3398	3452

Normal Non-Heating Season

(MMcf)

Requirements	83-84	84-85	85-86	86-87	87-88
Normal Firm S.O.	1734.	1725	1717	1710	1704
Interrup Sales	461	470	403	410	416
LNG Storage Refill	50	50	50	50	50
ST Storage Refill	136	150	150	150	150
	2381	2395	2320	2320	2320
Resources					
F-1	1900	1900	1900	1900	1900
I-1 and I-2 gas*	136	150	150	150	150
WS-1	70	70	70	70	70
LPA	75	75	-	-	-
LNG (take)	200	200	200	200	200
	2381	2395	2320	2320	2320

* I-1 and I-2 gas are used to refill storage during summer months.

Table 4 displays Fall River's projections of its sendout requirements and the supply sources which Fall River plans to utilize to meet the requirements throughout the forecast period.[17]

As indicated in Table 4, Fall River plans to meet its normal heating season firm requirements and the small level of heating season interruptible sales with its full contract quantities of its F-1, and WS-1 pipeline supplies. Fall River plans to use its entire storage capacity of ST-1 gas (180 MMcf) during the 1983-84 heating season, but less than the total available supplies during the following heating seasons (150 MMcf). For heating seasons through the 1986-87 split-year, Fall River plans to use the reduced allocation of SNG (303 MMcf) and the firm contract quantities of LNG from Bay State and DOMAC. In the 1987-88 heating season, the SNG will be replaced by increased firm quantities of LNG purchased from Bay State. Notably, however, Fall River projects using less than its firm contract quantities of LNG during the 1987-88 heating season. Fall River would try to sell back the surplus supplies.[18] Fall River projects that a portion of the net increase in supplies will be marketed to interruptible customers. Beginning in the 1985-86 split-year, Fall River expects to be able to let its propane contract expire. Until that time, however, Fall River does not plan to utilize all of its firm contract propane supplies. In each of the 1983-84, and 1984-85 heating seasons, Fall River plans not to utilize approximately 125 MMcf of firm propane.

Fall River's Supplement assumes that LNG supplies from DOMAC are delivered as scheduled. If a cargo of Algerian LNG is not delivered, however, Fall River might need to replace these supplies. See discussion, infra.

In the normal non-heating seasons throughout the forecast period, Fall River plans to utilize the maximum available quantities of F-1, and WS-1 pipeline supplies from Algonquin. Fall River also plans to utilize the firm DOMAC LNG through the forecast period, and the firm propane quantities through the 1985 non-heating season. Fall River's non-heating season supply plan depends on significant levels of sales to interruptible customers. Fall River plans to purchase interruptible gas as required from Algonquin under Algonquin's I-1 and I-2 Rate Schedules to refill storage. Fall River has indicated that Algonquin's offerings of interruptible supplies during the 1983-84 split-year have been greater than anticipated. Fall River accepts the offerings as needed depending on the need to fill storage and the anticipated sales to interruptible customers. In the absence of interruptible supplies, Fall River would utilize its F-1 supplies to refill storage and reduce its sales to interruptible customers.

B. Design Year

During a design year, Fall River must have sufficient gas supplies to meet the above-normal requirements of its temperature sensitive customers. Table 5 displays Fall River's additional requirements and available supplies during a design heating season.

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17. Fall River also must account for losses in the injection, withdrawal, and transportation of stored gas.
18. Response to Information Request S-4 dated November 28, 1983.

TABLE 5
Design Heating Season
(MMcf)

Requirements	83-84	84-85	85-86	86-87	87-88
Design Firm Sendout	3593	3558.9	3539.4	3522.1	3524
Normal Firm Sendout	3380	3346.5	3328	3311	3312
Additional Requirements	213	212.4	211.4	211.1	212
Resources					
ST-1	0	30	30	30	30
LPA	124	125	0	0	0
LNG (Bay State option)	87	87	87	87	262
LNG (storage)	100	100	100	100	100
Total	311	342	217	217	392
Interruptible Sales	124	126	70	87	140
	435	468	287	304	532

As indicated by Table 5, Fall River plans to meet its design heating season requirements primarily with LNG. Fall River plans to begin each heating season with 150 MMcf of LNG in storage and to send out 50 MMcf in a normal heating season. Thus, 100 MMcf would be available in a design year. In addition, in a design heating season, Fall River can exercise its option for the purchase of the optional LNG quantities under its contract with Bay State. During the 1983-84 and 1984-85 heating seasons, Petrolane propane is available for sendout under design conditions.

As indicated on Table 5, Fall River possesses sufficient supplies to meet its projected design year requirements. The Siting Council believes, however, that one observation is appropriate. Fall River plans to use its full contract quantities of DOMAC LNG to meet design heating seasons requirements. In this proceeding, the Siting Council has not investigated the reliability of DOMAC supplies. Nevertheless, in the event of nonarrival of an LNG tanker, Fall River might be required to replace these supplies. The diversion of interruptible supplies to replace the LNG is subject to timing and availability. The Siting Council ORDERS Fall River to present in its next Supplement a statement concerning the reliability of DOMAC LNG supplies, and a contingency plan for replacing, as necessary, these DOMAC supplies. The contingency plan should identify a standard for determining when replacement supplies are required and possible sources of replacement supplies.

C. Peak Day

Fall River must have adequate sendout capacity to meet the requirements of its firm customers on a peak day. Table 6 displays Fall River's peak day requirements and sendout capability.

TABLE 6
Peak Day
(MMcf)

	1983-84	1984-85	1985-86	1986-87	1987-88
Projected Requirements	43.6	46.0	46.7	46.8	47.1
Available Resources					
F-1	14.6	14.6	14.6	14.6	14.6
ST-1	1.8	1.8	1.8	1.8	1.8
WS-1	7.1	7.1	7.1	7.1	7.1
SNG-1	4.5	4.5	4.5	4.5	0.0
Vaporized LNG	20.0	20.0	20.0	20.0	20.0
Propane	12.0	12.0	12.0	12.0	12.0
	60.0	60.0	60.0	60.0	55.5

The Siting Council finds that Fall River has sufficient sendout capacity to meet peak day requirements.

D. Cold Snap

Fall River must have adequate sendout capacity to meet the requirements of its firm customers in the event of a cold snap. The Siting Council has defined a cold snap as a series of cold days at or near peak conditions. Fall River depends on propane and LNG to meet its firm requirements. Table 6 indicates that during the 1984-85, 1985-86, and 1986-87 heating seasons, Fall River will require 18 to 19 MMcf of propane and LNG per day to meet a cold snap at peak conditions. In the 1987-88 heating season, increased amounts of LNG and propane are required to replace SNG. Fall River has indicated that it plans to vaporize a maximum of 12 MMcf of LNG on a peak day.[19] Thus, Fall River will require approximately 6 to 7 MMcf per day of propane during the next three heating seasons, and 11 MMcf per day during the 1987-88 heating season, to meet a series of days at peak conditions.

If Fall River's LNG storage is at capacity, Fall River could vaporize 12 MMcf per day for almost two weeks without replenishing its storage.[20] Fall River could send out 12 MMcf of LNG per day for two weeks assuming an LNG inventory at half capacity and delivery of approximately seven truckloads of LNG per day. The Siting Council is satisfied with Fall River's ability to implement its plans for LNG vaporization during a cold snap.

A review of the plans for propane sendout is more difficult given Fall River's uncertain propane plans beyond the next heating season. Assuming full storage quantities of propane, Fall River could send out 6 MMcf of propane per day for almost a week without replenishing storage. Assuming propane storage quantities at half capacity, and two truckloads

19. Response to Information Request S-10 dated November 28, 1983. This level of planned vaporization would require approximately 14 truckloads of LNG per day without diminishing storage.

20. Fall River's LNG storage inventories were kept near capacity during the 1982-83 and 1983-84 heating seasons.

of propane per day, Fall River still could send out 6 MMcf of propane for five days. Assuming that Fall River maintains its LNG and propane inventories at reasonable levels during the heating season, the Siting Council finds that Fall River has sufficient sendout capacity to meet sendout during a cold snap.

The foregoing analysis presumes that a cold snap is composed of a series of peak days. In reality, such a series of peak days is unlikely to occur, and a different standard might be more appropriate. The Siting Council requests Fall River in its next Supplement to present a cold snap standard that it considers appropriate (for example, a standard based on a hypothetical cold snap similar to the one experienced in December 1980 and January 1981[21]). The analysis should clearly indicate the roles of propane, LNG, and trucking to meet daily sendout requirements during the cold snap.

V. Order

The Siting Council APPROVES the combined First and Second Supplement to the Second Long-Range Forecast of Fall River Gas Company subject to the comments in this Decision and to the CONDITIONS set forth below. Fall River's next Supplement is due on July 2, 1984.

1. Within ninety days Fall River Gas Company will provide to the Siting Council a compliance plan for presenting a complete and systematic method of documenting its forecast methodology. The Company shall meet with the Siting Council Staff within thirty days to discuss preparation of the compliance plan.

2. As part of its next Supplement, Fall River Gas Company shall provide statistical justification for its design year degree day standards.

3. In its next Supplement, Fall River Gas Company shall include an LNG contingency plan and a detailed cold snap analysis.

James G. White, Jr.

James G. White, Jr.

21. In its decision involving Boston Gas Company in Docket No. 83-25, the Siting Council analyzed the gas supplies available to Boston Gas to meet a two-week cold snap similar to that experienced from December 31, 1980 to January 13, 1981. That particular cold snap contained an average of 50 degree days per day.

Unanimously APPROVED by the Energy Facilities Siting Council on March 5, 1984 by those members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs); Walter Headley (for James S. Hoyte, Secretary of Environmental Affairs); Joellen D'Esti (for Evelyn F. Murphy, Secretary of Economic Affairs); Robert W. Gillette (Public Environmental Member); Thomas J. Crowley (Public Engineering Member).

9 March 1984
Date

Sharon M. Pollard
Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Fitchburg Gas and Electric Light Company for Approval of the Combined First and Second Supplements to the Second Long-Range Forecast of Natural Gas Requirements and Resources	)	Docket No. 83-11(A)

FINAL DECISION

James G. White, Jr.
Hearing Officer

On the Decision:
George Aronson, Director of Technical Analysis
Margaret Keane, Gas Analyst

The Energy Facilities Siting Council ("Siting Council") APPROVES subject to CONDITIONS the combined First and Second Supplements ("Supplement") to the Second Long-Range Forecast of natural gas requirements and resources of Fitchburg Gas and Electric Light Company ("Fitchburg" or the "Company").[1] The Supplement includes Fitchburg's projections through the 1987-88 split year.

I. Procedural History

Fitchburg filed its current Supplement on July 13, 1983. In accordance with the directions of the Hearing Officer, Fitchburg provided notice of this adjudication to the public by publication and posting. No petitions to intervene were filed. Fitchburg filed timely and complete responses to two sets of Information Requests of the Siting Council Staff.

II. Background

Fitchburg serves approximately 15,000 customers in Fitchburg and the towns of Ashby, Townsend, Westminster, and Gardner. Fitchburg sells roughly twice as much gas in the heating season as in the non-heating season. Total firm Company sendout in the 1982-83 split year was 2222 MMcf, making Fitchburg the eighth largest gas company in the Commonwealth, accounting for less than 2% of Massachusetts gas sales. Fitchburg's 1982-83 split-year firm sendout to its customer classes was as follows: residential with gas heating 53%, residential without gas heating 6%, commercial 18%, industrial 14%, Company use/unaccounted 8%. As indicated in Table 1, Fitchburg expects these percentages to remain relatively constant throughout the forecast period. Between 1978 and 1983, the Company's firm sales grew 12% on a weather-normalized basis as a result of gas conversions and new construction. Fitchburg projects a total growth rate of approximately 5% in total firm sendout during the five year forecast period.

III. Previous Conditions

The Siting Council's Decision on Fitchburg's Second Long-Range Forecast, 8 DOMSC 276, 296-97 (1982), contained two conditions :

1. That the Company meet with Council staff and/or members within sixty days of the issuance of a Final Decision in order to develop a forecast methodology which meets the statutory criteria of "...a projection of...gas requirements...based on substantially accurate historical information and reasonable statistical projection methods."

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1. The last decision of the Energy Facilities Siting Council ("Siting Council") involving Fitchburg Gas and Electric Light Company ("Fitchburg") concerned the Second Long-Range Forecast filed in 1981. Fitchburg Gas & Elec. Light Co., 8 DOMSC 276 (1982). The current review encompasses the combined First and Second Supplements. These two Supplements are composed of only one filing, and thus are referred to as a single supplement.

Table 1
Sendout by Customer Class
(MMcf)

	1983-84 Heating Season		1983-84 Non-heating Season		1987-88 Heating Season		1987-88 Non-heating Season	
RESIDENTIAL								
Heating	854	(54.3%)	416	(55.9%)	893	(53.9%)	435	(56.2%)
Non-Heating	83.5	(5.3%)	61.6	(8.3%)	79.6	(4.8%)	62.6	(8.1%)
COMMERCIAL	342	(21.7%)	128	(17.2%)	368	(22.2%)	131	(16.9%)
INDUSTRIAL	168	(10.7%)	120	(16.2%)	156	(9.4%)	110.4	(14.3%)
COMPANY USE/ UNACCOUNTED	126.5	(8.0%)	18.0	(2.4%)	159.4	(9.7%)	35	(4.5%)
TOTAL FIRM SENDOUT	1574	(100%)	743.6	(100%)	1656	(100%)	774	(100%)

This forecast should specifically include:

a. An explanation of its derivation of projected number of customers, usage per customer by class, and the use of these projections in forecasting sendout.

b. An adjustment of the Company's definition of normal and design years to reflect recent weather experience.

c. An adjustment to peak day design criteria, or an explanation why such criteria are sufficient.

2. That the Company submit to the Council no later than at its next meeting, a plan for meeting the contingency of the loss of 7.2 MMcf/day of sendout during a peak day or cold snap.

Pursuant to Condition 1, the Siting Council Staff met with the Company on December 14, 1982 to discuss problems in the Company's Second Long-Range Forecast, and to discuss remedies for the current filing. The Staff recommended that the Company discuss in its next Supplement the incremental changes it expects to make in its forecast in the next few years. The Company indicated that its Marketing and Sales Department has been merged with its Gas Production and Supply Department in a recent reorganization. The Company indicated its expectation that the two departments will work in conjunction to increase knowledge of the residential heat and commercial markets, which jointly comprise 76% of total sendout. Improvements made in compliance with Condition 1 are discussed infra, as appropriate. With respect to Condition 2, the Company complied fully by letter of January 11, 1983.

IV. Sendout Forecast

A. Normal Year

In the current Supplement, Fitchburg use a normal year of 6530 degree days, based upon an arithmetic average of thirty years of Bedford degree day data.[2] In its last filing, Fitchburg utilized a twenty-five year average. See 8 DOMSC at 282. Fitchburg states its intention in future filings to use a more recent history of combined Worcester and Bedford degree day data. Fitchburg's Supplement contains an Appendix indicating that, in recent years, the degree days registered in Fitchburg exceed those experienced at the Bedford Airport. The Siting Council believes Fitchburg's proposal to use combined data from Worcester and Bedford is appropriate, and expects to see this change implemented in the next Supplement.

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2. Fitchburg used Bedford data in this Supplement because it is the most complete data available at present. Table DD in the Supplement indicates that the normal year of 6530 degree days is based on the arithmetic average for 30 years of degree days. In the narrative portion of the Supplement, Fitchburg states that forty-nine years of data are included. The Siting Council requests Fitchburg to resolve this inconsistency in the next Supplement.

Fitchburg's normal year sendout requirements were calculated based on historical data reflected on an MMBtu basis. Historical sales data were converted from an Mcf basis to an MMBtu basis utilizing a conversion factor derived by dividing total MMBtu of gas supplies by total Mcf. Next, split year base and heating use per customer figures were calculated. In response to Information Request SO-7, reproduced as Table 2, Fitchburg provided a clear example of its calculation of split year heating use per residential heat customer. In response to Information Response SO-3, however, Fitchburg stated historical customer use per degree day factors "were derived and trended by comparison to actual degree days. Numbers were then selected for the forecast period based on the Company's judgement of what might be expected." The Siting Council has reservations with Fitchburg's use of statements such as "numbers were then selected" and the Company's judgement of what might be expected." These statements suggest that the data have been modified in ways that have not been documented, which undermines the Siting Council's confidence in the results of the forecast.

In response to Information Request SO-13, which asked for clarification of this statement, Fitchburg said that it had not identified any clear customer use trends from an analysis of Table G-1 data, and cited a number of factors as impacting customer use. These included price, weather, use of supplemental heat, and traditional conservation measures. The Company, however, neither explicitly quantified these factors nor ranked them in order of importance. In its response to Information Request SO-13, Fitchburg also stated that "[b]ecause Fitchburg's system in terms of load growth has been somewhat stable for the past two years, forecast customer use factors were trended predominantly based on actual 1982-1983 historical customer use factors." An example of the actual trending process would have enhanced the documentation here.

The type of language used in Fitchburg's documentation is not sufficient to document a quantitative forecast. Although the Siting Council believes it understands the Company's methodology, (i.e., Table 2), the Company bears the burden to document the methodology used to generate the forecast figures. The Siting Council is fully aware that judgement and territory-specific experience are important factors in arriving at reliable figures, but that does not remove the burden for documenting judgements and describing experiences. Thus, the Council hereby ORDERS the Fitchburg Gas and Electric Company to provide the Council within ninety days with a compliance plan that presents a systematic and complete method for documenting the Company's forecast methodology, including the judgements and experience that are the basis for interpretation of historical data. The Company shall meet with Council Staff within thirty days to discuss preparation of the compliance plan to satisfy this Condition, affixed hereto as Condition 1.

After converting historical data, Fitchburg analyzed the 1982-83 winter sendout utilizing 151 days of sendout and Bedford weather data. In line with the Company's policy of prohibiting growth that would increase peak day sendout, base load and space heating increments from

Table 2

1978-79 Split-year Heating Use per Residential Heat Customer
Per Degree Day (Example using Bedford Weather Data)

Average Annual Number of Customers = 7616
Number of Customers in August = 7452

Conversion Factor = 1.030 MMBtu/Mcf.

Nonheating Sendout =	326,723	Mcf	x	1.030	=	336,523 MMBtu
Heating Sendout =	647,479	Mcf	x	1.030	=	666,903 MMBtu
						1,003,426

Split-Year Base Use

$$\frac{(20{,}771)\ (1.030)}{7452} \text{ X } 12 = 34.5 \text{ MMBtu/Customer}$$

(34.5 MMBtu)(7616) = 262,752 MMBtu Annual Base Use

$$\frac{(1{,}003{,}426 - 262{,}752)}{(7616)\ (6423)} = .0152 \text{ MCF/Customer/DD}$$

Source: Response to Staff Information Requests SO-7.

1982-83 were used as a basis for deriving 1983-84 design and normal sendout projections.[3]

Next, Fitchburg "looked at a potential growth factor which would be achievable and fit within the current Company peak day criteria."[4] The Company's Marketing Department determined that it would be feasible to market an additional 30 MMcf annually in the residential with gas heat sector, equating to a 1.13% annual growth factor.[5] Fitchburg indicated there was approximately a 4.95% decrease in total weather normalized sendout from 1981-82 to 1982-83, attributable to factors including price of gas, use of supplemental sources, the recessionary economy and conservation. Fitchburg, however, stated that true conservation is the only factor that can be characterized as permanent load attrition. Citing the difficulty of ascertaining the extent of true conservation to any reliable degree, Fitchburg stated that by confining new load (30 MMcf, 1.13%) to a small segment of the total decrease experienced (4.95%), it is acting within the parameters of its policy not to add additional loads which will contribute to a peak load in excess of 19,500 Mcf.[6] The Siting Council is aware that the Company has not lost an insignificant amount of load to alternative fuels.[7]

After calculating and incorporating growth figures, the Company disaggregated total firm sendout by customer class. In line with its expectation that sendout will remain relatively constant with respect to class proportions, Fitchburg used historic percentages to disaggregate sendout by customer class. Next, Fitchburg assumed that the bulk of the 30,000 Mcf annual additional load would be marketed in the residential with heat class. An estimated annual use factor of 123 Mcf per customer was calculated based upon normalized historical data. Table 3 provides an example of the normalization calculation. The 30,000 Mcf growth figure was divided by 123 Mcf per customer to arrive at an anticipated number of new residential heat customers. Fitchburg states that customer additions were "adjusted to coincide with the expected sendout, split-year base use and heating use per customer per degree day factors.[8] For all other classifications the Company used historic ratios in calculating total projected sendout. On the whole, the Siting Council finds this an acceptable method of allocating new load for a company of Fitchburg's size. However, the Siting Council expects the

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3. Response to Information Request SO-3 dated November 10, 1983; Response to Information Request SO-10 dated November 10, 1983.
4. Response to Information Request SO-3 dated November 10, 1983.
5. Fitchburg bases its ability to market this gas on the premise that natural gas and No. 2 heating oil will be competitive, and that the Company will capture enough new homes and conversions to market the gas. Fitchburg also is studying markets with the potential for improving its annual load factor by including water heating, commercial loads, and industrial process loads. Response to Staff Information Request SO-14, January 11, 1984.
6. Response to Information Request SO-15 dated January 11, 1984.
7. See Response to Information Request SO-5, dated November 10, 1983.
8. Response to Information Request SO-3 dated November 10, 1983.

Table 3

Sample Normalization Calculation

<u>1982-83</u>

Split - Year Base Use/Customer Base Use/Customer/Day	$\frac{\text{34.1 MMBtu}}{\text{365 days}}$	= .0934 MMBtu/Day
Split - Year Heating Use/Customer/DD	.0137 MMBtu	

<u>Normalized Non-Heating Season Sendout</u>

Base Use (.0934 MMBtu/Day) (214 Days) (10,030)	= 200,476 MMBtu
Space Heating Increment (.0137) (1502DD) (10,030)	= 206,391 MMBtu
	406,867 MMBtu

<u>Normalized Heating Season Sendout</u>

Base Use (.0934 MMBtu/Day) (151 Days) (10,300)	= 141,457 MMBtu
Space Heating Increment (.0137) (5028DD) (10,300)	= 690,902 MMBtu
	832,359 MMBtu

Source: Response to Staff Information Request SO-16.

Company to address explicitly potential differences between new and existing customer use patterns in future filings, and to document its judgements on shifts in sendout patterns by existing customers in each class.

B. Design Year

Fitchburg used a design year of 7183 degree days, based on a 10% incremental addition to an arithmetic average of a thirty year history of daily Bedford degree day data. This is an improvement from the previous filing in which Fitchburg used only seventeen years of historical data. Fitchburg assumes all degree days occur during the heating season, creating a design heating season of 5681 degree days. Fitchburg's statistical analysis of the last 18 years of data indicates that the probability of a heating season having 5681 or more degree-days is one in 52.2 years. The Siting Council finds that Fitchburg's design year satisfies Condition 1b of the previous decision.

In forecasting design year sendout, Fitchburg used the same methodology as for a normal year. Fitchburg assumes that all additional sendout will take place during the heating season. Consequently, Fitchburg increases the forecasted normal year heating season sendout by 10% to arrive at total split year design sendout.

C. Peak Day

A "peak day" is the coldest day that is likely to occur during the forecast period. Fitchburg used 70 DD as its design criterion for peak days. This figure, an increase from the 66 DD figure used in past filings, was determined by examination of Bedford degree day data from 1934 to 1964. The coldest day which has actually been experienced to date in Fitchburg's service territory was 70 DD in 1980-81, which is the equivalent of a 66 DD in Bedford. The Siting Council finds this change satisfies Condition 1c in the last Decision.

The Company's projected peak day sendout, based on a 70 degree day for 1983-84, is 18.99 MMcf, a decline from the 1982-83 forecast figure of 20.7 MMcf. The Siting Council encourages the Company to continue monitoring the impact that changing market conditions, in the forms of load losses and gains in individual customer classes, will have on its peak day sendout requirements.

D. Conclusions

The Company's forecast of appears to be an adequate basis for supply planning. The Company has remedied a number of the Council's past concerns, notably calculations of design year and peak day standards. The Conditions affixed to the last Decision have been complied with to the Council's satisfaction. However, the Siting

Council remains concerned with the reviewability of the Company's submittals.[9] The Company bears the burden of documenting its forecast methodology to the satisfaction of the Council. Therefore, as stated previously, Condition 1 orders the Company to prepare a compliance plan that outlines the additional documentation requirements for Fitchburg's next filing.

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9. The Siting Council employs a three-pronged test in evaluating gas company forecasts. A methodology is appropriate if it is suitable in technical terms for the particular company. A methodology is reliable if it engenders confidence as a predictor of future events. The Siting Council can determine a forecast is reviewable if the forecast contains enough information to allow a full understanding of the projection of sendout requirements and the supply plan. Fitchburg Gas & Electric Light Co., 8 DOMSC 276, 281 (1982). In regard to the current Supplement, the Siting Council Staff compiled the bulk of the information in this Decision through the discovery process. The Siting Council has stated in the past that in recognition of changes in the Council over the years, and changes in the identity of intervenors, a filing should be self-contained and not require lengthy reference to prior dockets. See Northeast Util. Sys., Docket No. 81-17, at 87. Fitchburg supplied complete responses to the Staff's Information Requests in a timely manner. The Siting Council, however, believes Fitchburg's future filings would be improved by a more detailed narrative description of its sendout projections and its supply plan.

V. Resources and Facilities

A. Pipeline Supplies

Fitchburg has a contract with Tennessee Gas Pipeline Company ("Tennessee") which provides for the maximum delivery (MDQ) of 7.708 MMcf per day under Tennessee's CD-6 Rate Schedule.[10] The annual volumetric limitation (AVL) applicable to this contract is 7.693 MMcf per day for 365 days or 2808 MMcf per year. The contract has an initial termination date of November 1, 2000. The delivery point under this contract is in Worcester at the interconnection of Tennessee's pipeline and Fitchburg's distribution system.[11]

Fitchburg and Tennessee are in communication regarding a proposed revised MDQ, and a proposed revised AVL. Fitchburg has proposed changes in monthly AVL components which would shift 200 MMcf of CD-6 supplies from the non-heating to the heating season. Fitchburg also has proposed an increase of 2.5 MMcf in the MDQ.[12]

B. Storage Return Gas

Fitchburg injects pipeline gas into storage in the summer and withdraws the stored gas in the winter. Fitchburg's contract with Penn-York Energy Corporation ("Penn-York") provides for 139.9 MMcf of storage.[13] Penn-York has agreed to provide an annual storage volume of 300 MMcf (308,100 MMBtu at current Btu value) and the Federal Energy Regulatory Commission has approved that annual storage volume. Fitchburg, however, has been unable to obtain transportation for these storage volumes. Fitchburg and Tennessee have entered into a transportation contract under which Tennessee provides only best efforts transportation for 1.27 MMcf per day up to the total winter volume of

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10. The contract between Fitchburg and Tennessee Gas Pipeline Company ("Tennessee") was amended on June 4, 1981, and superseded the prior contract between the same parties which contained an expiration date of November 1, 1988. The volumetric figures in this section represent volumes at 1000 MMBtu/Mcf.
11. Fitchburg's filing states that Tennessee has indicated a slight possibility of curtailment in the 1985-86 time frame. In response to an Information Request, Fitchburg stated Tennessee is unable at this time to quantify the possibility of curtailment. The Siting Council requests that Fitchburg monitor this issue closely and include a statement concerning the reliability of full Tennessee supplies in the next Supplement.
12. Response to Information Request S-19 dated January 11, 1984.
13. The "Underground Storage Service Agreement" between Fitchburg and Penn-York Energy Corporation (Penn-York) was executed on August 3, 1982, and superseded the prior contract between the same parties dated May 21, 1981. The new Agreeement runs until 1995, but the Federal Energy Regulatory Commission has granted a temporary certificate only until April 1, 1985. Nat'l Fuel Gas Supply Corp., Docket No. 76-492-021 (June 29, 1982).

139.9 MMcf.[14] Due to Tennessee's inability to provide either firm transportation, or increased best efforts transportation, Fitchburg and Penn-York executed the storage agreement without reference to the additional available storage capacity.

Fitchburg and Consolidated Gas Supply Corporation ("Consolidated") are parties to a Storage Service Agreement under which Consolidated supplies a maximum storage quantity of 51.35 MMcf and a maximum daily withdrawal of .468 MMcf.[15] Transportation is provided by Tennessee on a firm basis up to .468 MMcf per day.[16]

C. LNG

In August 1982, Fitchburg amended its 1976 LNG contract with Bay State Gas Company ("Bay State") to provide for additional quantities of LNG through the 1987-88 heating season, as shown in the following table (MMcf):

	1982 Amendment			1978 Contract		
	Firm	Optional	Total	Firm	Optional	Total
April-Oct.	10	0	10	5	0	5
November	26	0	26	6	0	6
December	52	8.75	60.75	30	0	30
January	80	32.50	112.50	42	10	52
February	45	23.75	68.75	30	20	50
March	37	10.00	47.00	12	10	22
	250	75	325	125	40	165

There is no direct pipeline interconnection between the Fitchburg and Bay State distribution systems. Thus, the contract provides for Bay State to deliver the LNG by truck to Fitchburg. Pursuant to the terms of the contract, Fitchburg can elect to receive propane instead of LNG. Fitchburg verbally requests deliveries of LNG or propane on one day advance notice. Under the amended contract, Fitchburg can request a

14. The best efforts storage transportation contract was executed on August 1, 1982, and contains an initial expiration date of March 31, 1995. Fitchburg has informed Tennessee that Fitchburg would like to receive firm transportation for full Penn-York storage volumes beginning with the 1986-87 winter.
15. The Service Agreement between Fitchburg and Consolidated is dated February 18, 1980 and terminates in the year 2000 with the possibility of yearly extensions.
16. The transportation is provided on a firm basis pursuant to a letter agreement between Fitchburg and Tennessee dated October 28, 1981.

total of eight trucks of supplemental gas in a 24-hour period.[17] During March 1983 and the current heating season, Tennessee has been able to provide best efforts transportation by displacement on its pipeline from Bay State to Fitchburg of approximately one-half of the LNG under the Bay State contract. By avoiding trucking costs, Fitchburg saves approximately 31 cents per Mcf for the volumes delivered by pipeline displacement.

Fitchburg leases on-site LNG storage and vaporization facilities in Westminster. LNG storage capacity is limited to 4.17 MMcf, and the peak day sendout capability is 7.2 MMcf.[18]

D. Propane

Fitchburg is a party to two contracts for purchase of propane which expire at the end of the 1984-85 heating season. The contract with C.M. Dining, Inc. calls for Fitchburg to purchase the following quantities of propane (Mcf):[19]

	Firm	Optional	Total
April-October	0	0	0
November	3990	0	3990
December	19952	0	19952
January	27933	13301	41234
February	19952	26603	46555
March	7981	13301	21282
Total	79808	53205	133013

Transportation is provided by C.M. Dining up to a maximum of four trucks, or a total of approximately 3.34 MMcf in a 24-hour period.

Fitchburg has an agreement[20] with Petrolane Northeast Gas Service, Inc. for the annual purchase of 30 MMcf and 20 MMcf of firm and optional quantities respectively. Fitchburg can request up to 3 truckloads of propane per day on 24 hours notice. The delivery schedule under the agreement is as follows (Mcf):

17. A truck of LNG contains .9 MMcf. Response to Information Request S-14. A propane truck contains an average of 9100 gallons or approximately .835 MMcf per truck. Response to Information Request S-11.
18. The maximum one-day sendouts in the 1982-83 and 1980-81 heating seasons were 6.3 MMcf (7236 MMBtu) and 4.9 MMcf respectively.
19. Fitchburg purchases the firm volumes on a take or pay basis. Fitchburg informs C.M. Dining, Inc. of the amount of optionals to be purchased 10 days before each month. These volumes become firm volumes. A 3-cent per gallon penalty is charged to Fitchburg for optional gas not purchased.
20. The Agreement is dated August 26, 1980. The terms of purchase including take-or-pay provisions, election of optional quantities and a penalty for optional gas not elected are virtually identical to the terms in the C.M. Dining contract.

	Firm	Optional	Total
April-October	0	0	0
November	1513	0	1513
December	7568	0	7568
January	10595	5045	15640
February	7568	10090	17658
March	3026	5045	8071
Total	30270	20180	50450

Both the propane contracts require Fitchburg by April 1, 1984, to elect to extend the contract for five years or to continue the purchases on a contract year basis. Thus, Fitchburg must notify the propane suppliers by April 1, 1984, if Fitchburg desires to terminate these contracts at the end of the 1984-85 heating season.

Fitchburg has indicated that increased firm transportation of stored pipeline gas, and deliveries of gas from Canada, would enable it to reduce its use of higher-cost supplemental fuels. Indeed, Fitchburg's current Supplement indicates a reduced reliance on propane in 1985 with the commencement of deliveries from the Boundary Gas project. The Siting Council is concerned about long-term renewal of these propane contracts when other alternatives such as Boundary Gas, or shorter term propane contracts might provide more flexibility. Fitchburg is encouraged to examine closely its plans for future propane supplies in light of alternatives, and should be prepared to justify its decision to the Siting Council.

Fitchburg owns a propane air peak shaving facility in Lunenburg with a maximum daily design capacity of 7.2 MMcf and storage capacity of 30.4 MMcf.[21]

E. Canadian Gas

Fitchburg has entered into a Precedent Agreement with Boundary Gas, Inc. for the purchase of 500 Mcf per day or 182.5 MMcf per year with delivery now anticipated for the 1986-87 heating season. As presently envisioned by Fitchburg, the Boundary Gas agreement would be for ten years with a 75 percent annual take-or-pay provision. To maintain this minimum take, Fitchburg would take 500 Mcf per day during the heating season and 285 Mcf per day during the non-heating season. An eleventh year would be available to take "make-up" gas not taken during the normal contract period.

Fitchburg also is currently involved in negotiations for a potential supply of 1.5 MMcf per day from Sable Island beginning in the 1989-90 time frame.

21. The propane sendouts for the 1980-81, 1981-82, and 1982-83 heating seasons were 245 MMcf, 201 MMcf and 171 MMcf respectively.

F. Conservation Programs

The Siting Council evaluates conservation programs as a supply source on the same basis as other supply sources.[22] The Siting Council considers these programs as part of its mandate of ensuring necessary gas supplies at the lowest possible cost with a minimum impact on the environment. Mass. Gen. Laws Ann. ch. 164, sec. 69H. Fitchburg has mentioned that its audit program, to the extent utilized by existing customers, will conserve energy.[23] At a time when Fitchburg is considering its future propane requirements as well as potential Canadian supplies, the Siting Council believes that conservation programs should receive concurrent attention. The Siting Council requests Fitchburg to address such programs in detail in its next Supplement, and the potential impact and cost-effectiveness on its supplies.

VI. Comparison of Resources and Requirements

The Siting Council's last Decision involving Fitchburg addressed Fitchburg's ability to meet peak day, design year and cold snap requirements based on actual historical data. In reviewing Fitchburg's current supply plan the Siting Council also has compared resources and requirements in a normal year, in addition to the reviews performed in the last decision.

A. Normal Year

In a normal year, Fitchburg must have adequate supplies to meet several types of requirements. First and most importantly, Fitchburg must meet the requirements of its firm customers. Secondly, Fitchburg must insure that its underground storage facilities are filled prior to the start of the heating season. To the extent possible, Fitchburg also supplies gas to its interruptible customers.[24] Table 4 displays Fitchburg's projections of these requirements and the supply sources to meet these requirements in the heating and non-heating seasons for the forecast period.

As indicated in the Table, Fitchburg proposes to meet its normal heating season firm requirements and the small level of heating season sales to interruptible customers with its firm and best efforts contract quantities of underground storage return gas and propane, and almost the entire firm annual contract quantities of LNG. Fitchburg plans to take less than the total available quantity of CD-6 pipeline gas from

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22. A distinction is to be made between "conservation" in the form of the observation of reduction in customer consumption (See Response to Information Request SO-2(c)), and "conservation programs" which constitute deliberate action by a gas company undertaken to meet requirements which would otherwise be met from conventional supply sources.
23. Response to Information Request SO-2(c) dated November 10, 1983.
24. Fitchburg also must account for losses in the injection, withdrawal, and transportation of stored gas.

Table 4
Normal Heating Season
(MMcf)

Requirements	83-84	84-85	85-86	86-87	87-88
Normal Reqs.	1574	1593	1615	1635	1656
Interruptibles	35	35	35	35	35
	1609	1628	1650	1670	1691
Resources					
CD-6	1068	1087	1088.5	1108.5	1129.5
Storage	191	191	191	191	191
LPA	110	110	55	55	55
LNG	240	240	240	240	240
Boundary	-	-	75.5	75.5	75.5
Total	1609	1628	1650	1670	1691

Normal Non-Heating Season
(MMcf)

Requirements	83-84	84-85	85-86	86-87	87-88
Firm Sendout	744	750	758	766	774
Underground Storage Refill	191	191	191	191	191
Interruptible Sales	450	500	515	500	475
	1385	1441	1464	1457	1440
Resources					
Tennessee CD-6	1363	1431	1454	1385.6	1368.6
Storage Return	-	-	-	-	-
Propane-Air	-	-	-	-	-
LNG	10	10	10	10	10
FEDCo[25]	12	-	-	-	-
Boundary	-	-	-	61.4	61.4
	1385	1441	1464	1457	1440

25. FEDCo's exploration efforts have been terminated.

Tennessee, but also plans to use 75.5 MMcf from Boundary Gas beginning in the 1985-86 heating season and continuing through the forecast period.[26]

The portion of Table 4 representing Fitchburg's available resources in a normal non-heating season indicates a reliance on the availability of the total amount of gas stored storage under the Penn-York and Consolidated contracts. As indicated previously, there is no firm transportation associated with the Penn-York storage capacity of approximately 140 MMcf. Additionally, the availability of the total storage capacity of 191 MMcf depends on the daily sendout pattern over the course of the heating season. Fitchburg must receive both its firm transportation of storage gas from Consolidated and the maximum daily best efforts transportation of Penn-York storage volumes for 110 days to receive the total stored volume of 191 MMcf. Fitchburg's daily sendout data for the months of November and December 1983 shows that on 28 of the 61 days during that period, Fitchburg took none of its firm Consolidated supplies. Thus, Fitchburg would need to take its full Consolidated supplies on 77 of the remaining 91 days of the 1983-84 heating season in order to receive its total available Consolidated storage volumes. The same observation applies to the Penn-York storage volumes with the added complication that transportation of these volumes is available only on a best efforts basis. Indeed, Fitchburg's daily sendout data indicates that during extremely cold weather, Fitchburg cannot rely on the best efforts transportation up to the maximum contract quantity.[27] Thus, the Siting Council is not convinced that gas will be delivered from underground storage in the quantities projected by Fitchburg in a normal year.

In the non-heating season, Fitchburg plans to meet its firm requirements, refill underground storage, and make the significantly larger level of sales to interruptible customers by using its CD-6 pipeline supplies from Tennessee, a small amount of LNG, and supplies of

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26. The quantity of CD-6 gas not taken is projected to decline over the forecast period from 93 MMcf in the 1983-84 heating season to 31.5 MMcf in the 1987-88 heating season. Table G-22 in Fitchburg's Supplement indicates that 72.5 MMcf of CD-6 gas would not be used during the 1985-86 heating season assuming Boundary gas volumes are available in that heating season. If the 75.5 Mcf of Boundary gas is not available until a year later, Fitchburg could take its full CD-6 volumes as an offset to anticipated Boundary volumes on a seasonal basis. Daily delivery constraints, however, could prevent a one-for-one substitution.
27. See Response to Document Request D-10 dated January 11, 1984.

Boundary gas beginning in 1986. Again, Fitchburg plans to take less than its available pipeline supplies from Tennessee.[28]

On the basis of the above tables, the Siting Council concludes that Fitchburg has sufficient supplies on a seasonal basis to meet its requirements in a normal year subject to the availability of transportation.

B. Design Year

During a design year, Fitchburg must have sufficient gas supplies to meet the sendout requirements of its temperature sensitive customers, above normal year requirements. Table 5 displays Fitchburg's requirements and available supplies in a design year.

Table 5 indicates that Fitchburg has sufficient supplies to meet requirements in a design year on a seasonal basis. In the event of a design heating season, Fitchburg has available significant quantities of CD-6 Tennessee gas which Fitchburg does not plan to use during a normal heating season. Fitchburg also can elect to utilize its optional quantities of LNG and propane, and its stored quantities of LNG or propane.[29] Fitchburg also can call on supplies that in a normal year are diverted to interruptible customers. Fitchburg plans to utilize its full underground storage volumes in the course of meeting its normal requirements. Thus, these are unavailable in a design year.[30]

As in the case of a normal heating season, the adequacy of supplies depends on daily sendout developments over the course of the entire heating season. As indicated earlier, the total quantity of storage return gas may not be available due to best efforts transportation, and to the fact that storage gas not received in the early part of the heating season may be unavailable due to daily transportation limits in the rest of the heating season. This issue is sufficiently serious for the Siting Council to view this portion of the supply plan with some concern. The Siting Council ORDERS Fitchburg to address the reliability of storage return gas in its next Supplement with reference to the daily dispatch constraints noted in this Decision. The Siting Council Staff is available to discuss compliance with this CONDITION, affixed hereto as Condition 2.

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28. The additional available volumes of Tennessee CD-6 gas during the non-heating season range from 200 MMcf to 291 MMcf during the forecast period. Fitchburg plans to use 191 MMcf each year to refill underground storage. During the 1986 non-heating season, Fitchburg would still have 77.4 MMcf of CD-6 gas after filling storage in the event that the anticipated Boundary volumes are not available until the next year.
29. Fitchburg plans to have 24.3 MMcf of propane and 3.9 MMcf of LNG in storage at all times. Fitchburg plans to meet its normal requirements without resort to these stored volumes. In the event of depletion, Fitchburg would have to replenish the storage volumes.
30. Fitchburg's supply plan for a design heating season does not include Boundary gas volumes above 500 Mcf per day.

Table 5

Design Heating Season
(MMcf)

Requirements	83-84	84-85	85-86	86-87	87-88
Design Firm Sendout	1726	1748	1771	1793	1817
Normal Firm Sendout	1574	1593	1615	1635	1656
Excess Required in Design Year	152	155	156	158	161
Resources					
CD-6	93	74	72.5	52.5	31.5
Underground Storage	-	-	-	-	-
Propane (take)	72	72	36	36	36
(storage)	24.3	24.3	24.3	24.3	24.3
LNG (take)	75	75	75	75	75
(storage)	3.9	3.9	3.9	3.9	3.9
Interruptibles	35	35	35	35	35
Additional Supplies Available	303.2	284.2	246.7	226.7	205.7

Design Non-Heating Season
(MMcf)

Requirements	83-84	84-85	85-86	86-87	87-88
Design Firm Sendout	744	750	758	766	774
Normal Firm Sendout	-744	-750	-758	-766	-774
Excess Required in Design Year	0	0	0	0	0
Resources					
Tennessee CD-6	100	32	9	77	94
Storage Return	-	-	-	-	-
LNG (take)	-	-	-	-	-
LNG (storage)	3.9	3.9	3.9	3.9	3.9
Propane (take)	-	-	-	-	-
(storage)	24.3	24.3	24.3	24.3	24.3
Boundary	-	-	-	46.1	46.1
Interruptibles	450	500	515	500	475
Additional Supplies Available	578.2	560.2	552.2	651.7	644.3

In a design non-heating season, Fitchburg does not expect its requirements to exceed those in a normal non-heating season. Fitchburg anticipates the identical firm sendout, sales to interruptible customers and storage refill requriements as in a normal year. Fitchburg has Tennessee CD-6 pipeline supplies, stored supplemental supplies, and Boundary Gas supplies (beginning in 1986) available beyond its normal resources to meet any unanticipated sendout requirements in a design non-heating season. If required, Fitchburg can reduce its interruptible sales until its underground storage is at capacity.

C. Peak Day and Cold Snap

Fitchburg must have adequate sendout capacity to meet the requirements of its firm customers on a peak day and in the event of a cold snap. Table 6 below displays Fitchburg's peak day sendout capacity and indicates that Fitchburg's capacity is adequate under normal facility operating conditions.

Table 6
Peak Day
(MMcf)

	83-84	84-85	85-86	86-87	87-88
Tennessee CD-6	7.6	7.6	7.6	7.6	7.6
Firm Storage Return	.5	.5	.5	.5	.5
Propane	7.2	7.2	7.2	7.2	7.2
LNG	7.2	7.2	7.2	7.2	7.2
Boundary	-	-	.5	.5	.5
Total	22.50	22.50	23.00	23.00	23.00
Peak Sendout	18.99	19.23	19.48	19.73	19.99
Excess	3.51	3.27	3.52	3.27	3.01

As expressed in our last decision, Fitchburg relies heavily on its supplemental supplies and the accompanying sendout facilities to meet peak day requirements. Under terms of the applicable contracts, Fitchburg can receive eight trucks of LNG representing 7.2 MMcf, and seven trucks of propane representing 5.84 MMcf per day. Thus, Fitchburg has the ability to meet its projected peak day requirements throughout the forecast period of approximately 19 MMcf without using stored quantities of these supplementals. Fitchburg, however, is dependent on trucking and proper functioning of its equipment. In regard to the latter, Fitchburg has two LNG vaporizers with sendout capacities of 7.2 MMcf per day, but due to operating constraints only one is operable at a given time. The back-up vaporizer, however, provides protection in the event of failure of the other unit. Fitchburg also can vaporize LNG directly from an LNG truck if the storage tank becomes unusable, and has contingency plans and spare parts available for the event of an LNG control system or mechanical failure, or an unloading problem on a peak day. Although Fitchburg does not have backup propane vaporization, Fitchburg also has a contingency plan and spare parts in the event of problems with the propane system. Due to the critical nature of supplemental supplies on a peak day, the Siting Council encourages continued vigilance in regard to these facilities.

The Siting Council has defined a cold snap as a number of days in succession during the heating season at or near design conditions. In order to meet cold snap requirements, a gas company must maintain high rates of sendout over an extended period by supplementing its pipeline supplies with LNG and propane. Thus, a gas company must store or have access to sufficient quantities of supplemental supplies. Assuming no replenishment of propane and LNG, and full storage quantities, Fitchburg could meet only three consecutive days at peak projected sendout of 19 MMcf for the 1983-84 heating season. To meet a prolonged period of peak day send out at approximately 19 MMcf, Fitchburg would be required to send out daily approximately 11 MMcf of propane and LNG. Under terms of the applicable contracts, Fitchburg can request delivery of eight trucks of LNG per day and seven trucks of propane per day, representing 7.2 MMcf of LNG and 5.84 MMcf of propane,[31] or a total of 13.04 MMcf. Thus, Fitchburg possesses sufficient access to supplemental supplies to meet cold snap requirements. Due to Fitchburg's dependence on trucking, however, the Siting Council requests Fitchburg to provide an update in its next Supplement of its contingency plan for meeting both peak day and cold snap requirements.[32]

D. Conclusion

The Siting Council approves Fitchburg's supply plan. The Siting Council is satisfied that Fitchburg is diligently analyzing supply options in an ongoing effort to afford an economical yet secure supply mixture.[33] In particular, the Siting Council notes Fitchburg's negotiations with Tennessee to increase firm transportation of underground storage, and to shift 200 MMcf of Tennessee CD-6 gas to the winter period. Although currently available on a best-efforts basis, the availability of Bay State LNG for delivery by displacement is also a favorable development. As indicated above, however, Fitchburg will be required to justify its reliance on full Penn-York and Consolidated storage quantities. Also, Fitchburg is requested, as discussed herein, to discuss conservation programs in its next Supplement, and to update its contingency plans for meeting peak day and cold snap requirements.

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31. Figures based on Fitchburg's responses to Information Requests S-11, and S-14.
32. In its most recent decision involving Boston Gas Company in Docket No. 83-25, the Siting Council analyzed the gas supplies which were available to Boston Gas to meet a two-week cold snap similar to that experienced from December 31, 1980 to January 13, 1981. That particular cold snap contained 703 degree days, or an average of 50 degree days per day. The Siting Council believes a similar analysis would be appropriate for Fitchburg's future filings. During the period December 19-27, 1983, Fitchburg experienced a cold snap composed of 451 degree days or an average of 50 degree days per day. Fitchburg vaporized an average of 2.19 MMcf per day of LNG, and an average of 2.64 MMcf of propane. Fitchburg, however, received 1 MMcf per day by displacement from Bay State, as well as small quantities of best efforts storage return gas from Penn-York and some interruptible pipeline gas from Tennessee.
33. Fitchburg has indicated that its plans regarding an extension of the Bay State contract beyond 1988 are contingent on other factors such as Boundary Gas, and Sable Island.

VII. Order

The Siting Council APPROVES the combined First and Second Supplements to the Second Long-Range Forecast of Fitchburg Gas and Electric Light Company. As CONDITIONS to this approval, Fitchburg shall be required to meet the two conditions listed below. The Company's next Supplement is due on July 2, 1984.

1. Within ninety days, provide a compliance plan for submitting improved documentation for future forecasts.

2. Include in its next Supplement, a discussion of the reliability of full underground storage quantities during the heating season.

James G. White, Jr.

James G. White, Jr.
Hearing Officer

Unanimously APPROVED by the Energy Facilities Siting Council on March 5, 1984 by those members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs); Walter Headley (for James S. Hoyte, Secretary of Environmental Affairs); Joellen D'Esti (for Evelyn F. Murphy, Secretary of Economic Affairs); Robert W. Gillette (Public Environmental Member); Thomas J. Crowley (Public Engineering Member).

9 March 1984
Date

Sharon M. Pollard
Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Boston Edison Company for Approval of its First and Second Supplements to its Second Long-Range Forecast (1983- 1992) of Electric Power Needs and Requirements (including the requirements of the Concord Municipal Light Plant, the Norwood Municipal Light Department, and the Electric Division of the Wellesley Board of Public Works)	)	EFSC Nos. 83-12, 83-40, 83-41 and 83-45.

FINAL DECISION

Lawrence W. Plitch, Esq.
Hearings Officer
March 5, 1984

On the Decision:

Susan Fallows Tierney
George Aronson

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The Energy Facilities Siting Council hereby APPROVES conditionally the First and Second Supplements to the Second Long-Range Forecast of Electric Power Needs and Requirements ("Forecast") as submitted by Boston Edison Company ("Boston Edison", or "the Company").

The first section of this review of the Forecast describes the history of the current and previous proceedings. The next section contains a review of the methodology and data that Boston Edison uses to forecast demand for electricity in its service territory. The third section analyzes the adequacy, diversity and cost of Boston Edison's supply plan. The final section contains the order approving Boston Edison's Forecast, along with Conditions attached to the approval.

I. BACKGROUND AND PROCEDURAL HISTORY

Boston Edison Company is an investor-owned utility engaged in the manufacture, purchase, transmission, distribution, and sale of retail and wholesale electrical energy, and in the production, distribution, and sale of steam energy. In 1982, Boston Edison provided retail service to 615,668 customers in 40 cities and towns in the greater Boston metropolitan area.[1] Additionally, Boston Edison sells wholesale electricity to 30 customers (largely municipal light boards). Annual retail sales totalled 9,466,134 MWH in 1982, representing approximately 28 percent of the total electricity sold at the retail level in Massachusetts that year.[2] Boston Edison services a largely urbanized area, with a high percentage of retail sales to the commercial sector (52 percent) and a summer-peaking load.[3]

The Concord Municipal Light Plant, the Norwood Municipal Light Department, and the Wellesley Board of Public Works, Electric Division, are three municipally-owned electric utilities that receive all of their power requirements from the Boston Edison Company. Sales to these three muncipals account for approximately 5% of the Company's total territorial sales, and comprise approximately 5% of its summer peak demand. Insofar as the Company is contractually obligated to supply the total requirements of these municipals, their peak demands are included in the Company's forecast of total system demand (See Forecast, Vol. 1, at F-1 and H-8). Consequently, the Council's review of Boston Edison's demand forecast and supply plan simultaneously satisfies our mandate to insure that these three municipal utilities have sufficient resources to meet their requirements.

A. The Past Proceeding

The Energy Facilities Siting Council ("EFSC", or "the Council") last issued a Decision on a Boston Edison Forecast on March 2, 1982. In that Decision, EFSC Docket No. 81-12, 7 DOMSC 93 (1982), the EFSC

1. Boston Edison, FERC Form No. 1: Annual Report of Electric Utilities, Licenses and Others, December 31, 1982, at 301.
2. Boston Edison, FERC Form No. 1, at 301; and Electric Council of New England (ECNE), Electric Industry in New England - Statistical Tables, 1982, at 8.
3. Boston Edison, Long-Range Forecast of Electric Power Needs and Requirements: 1983-2000, Vol.1, at H-9.

approved the Company's Second Long-Range Forecast (1981-1990). The demand forecast was unconditionally approved, and the Council noted major advancements in the methods that the Company used to forecast demand. The EFSC approved the supply plan subject to three conditions:

1. That the Company make available to the Council Staff on a confidential and proprietary basis a copy of the winning firm's proposal to study coal conversion at Mystic Units 4-6 and New Boston as soon as the Company makes its choice. The Company should provide its next "status report" in April, 1982 and monthly thereafter".

2. That the Company continue its current data collection efforts as part of an effort to determine how electricity is and will be used by existing and new customers in the commercial sector. It should evaluate information services, rate incentives, technical assistance, and financial incentives which it might offer to its commercial customers as part of a comprehensive conservation and load management program. The Company should describe its process of evaluation, report its results, and propose a demand management program utilizing those measures which conform to appropriate cost-effectiveness standards as established by the Company, as part of its next filing with the Council.

3. It is further ordered that the Company submit its First Supplement to the Second Forecast by September 1, 1982.

By letter agreement dated December 2, 1982, the Company was granted an extension in its filing date to February 1, 1983. Due to the timing of the filing, it was considered to be the combined First and Second Supplements to the Second Long-Range Forecast.

B. <u>The Current Proceeding</u>

Boston Edison submitted the First Supplement to its Second Long-Range Forecast (EFSC 82-12) in two parts. The first volume, the demand forecast for the years 1983 through 2000, was filed on February 1, 1983. The Company submitted the supply plan, Volume 2, on March 1, 1983. Upon filing the second volume, the Petition was considered complete. Boston Edison gave proper notice of the adjudicatory proceeding by publication in several local newspapers and by postings at every city and town hall within the Company's service territory. No new facilities were proposed in the Forecast, though the Company identified several potential transmission problems that may result in proposals to construct facilities in the near future.

The Hearing Officer received one petition to intervene from Susan Fallows, staff intervenor for the Energy Facilities Siting Council. No other petitions to intervene were filed in this Docket.

A Pre-Hearing Conference was held on April 5, 1983, and was attended by legal and technical representatives of Boston Edison, the EFSC Hearing Officer and staff analyst, and EFSC Staff Intervenor Susan Fallows. The Company expressing no opposition, the Hearing Officer allowed the petition to intervene by Ms. Fallows. The parties agreed to proceed without formal hearings.

Several technical sessions were held between the EFSC staff analyst, the EFSC staff intervenor and the Boston Edison forecasting and planning staffs. Demand issues were reviewed at sessions on April 21 and April 26, 1983. Supply issues were discussed on April 27, 1983. On May 9, 1983, both the EFSC Staff Intervenor and the Hearings Officer each issued sets of information requests to which the Company provided responses on June 5, 1983. Another technical session on the demand related issues took place on July 19, 1983.

In June, 1983, Intervenor Fallows resigned her position at the EFSC in order to take a job as staff economist at the Massachusetts Executive Office of Energy Resources. The parties agreed that Ms. Fallows could continue to advise the EFSC staff in this case so as to avoid losing the time and resources that had been expended by all parties up until that point. See Letter from L.W. Plitch, EFSC Hearings Officer, to M.B. Stanton, Boston Edison Counsel (June 24, 1983).

Pursuant to Condition 1 of our 1982 Decision, Boston Edison provided monthly status reports on coal conversion to the Council in April, May, and June, 1982. On July 1, 1982, Boston Edison released its IMPACT 2000 report, a comprehensive study of the Company's long-run conservation and supply strategies. (See Sections II.F., III.A., III.B., and III.C., infra). At that time, the Council agreed to allow the Company to satisfy the remaining requirements of Condition 1 (monthly coal conversion status reports) by filing with the Council all coal-conversion-related documents submitted by the Company to other agencies (e.g., the Department of Public Utilities and the Executive Office of Environmental Affairs). See Letters of July 27, 1982, and December 2, 1982.

Boston Edison provided the Council with copies of its IMPACT 2000 reports dated July 1, 1982, and October 1, 1982. In addition, it has provided: Environmental Notification Forms and Draft Environmental Impact Reports ("DEIR") for the coal conversion projects at Mystic and New Boston; comments on the DEIR's by the Department of Environmental Quality Engineering; and assorted materials related to coal conversion from the record in its rate case at the Department of Public Utilities (DPU 1350). More recently, the Company provided the Council with copies of letters (dated January 24, 1984) from Thomas J. Galligan, Chairman of Boston Edison, and John R. Stevens, Vice President, which described the Company's proposal to add scrubbers at New Boston. Consequently, the Council is satisfied that the Company has complied with Condition 1 to our 1982 Decision.

Pursuant to Condition 2 of our 1982 Decision, Boston Edison has responded with two major initiatives. First, the Company has adopted an entirely new end-use model to forecast commercial demand, with associated data collection activities (See Section II.D., infra). Second, the Company has initiated a comprehensive conservation and load management program (See Section III.C., infra) as part of its IMPACT 2000 report. Having reviewed and analyzed these initiatives, the Council is satisfied that the Company has substantially complied with Condition 2 to our 1982 Decision. However, the Council retains certain reservations in this area and has expressed these in the appropriate, previously-cited sections of this Decision.

II. ANALYSIS OF THE DEMAND FORECAST

The regulations of the Energy Facilities Siting Council (EFSC Regulations, Chapter 6, Sec. 62.9) require that electric utility demand forecasts be based on accurate and complete historical data and that they utilize reasonable statistical methods. The Council has traditionally evaluated the reasonableness of a company's methodology by applying three standards of review: the appropriateness of the methodology (i.e., whether it is technically suitable to the size and nature of the utility's system); its reviewability (whether it is documented so that the results could be evaluated and duplicated by another person, given the same level of technical resources and expertise); and its reliability (whether it is capable of inspiring a degree of confidence that its data, assumptions, and judgments will produce a forecast of what is most likely to occur in the future).

In its review of Boston Edison's previous long-range forecast in EFSC 81-12, the EFSC commended the Company for the significant progress it had made in improving the quality of its forecasting methodology since 1976.[4] Based on an extensive record of evidence, the EFSC found that Boston Edison had a "sophisticated and credible model" that compared "quite favorably with those of other Massachusetts utilities of similar size and with similar resources."[5] While the Council approved the forecast without conditions, the Decision and Order encouraged the Company to continue the progress it had made in its forecasting and data-collection efforts.

The current review of Boston Edison's newest long-range forecast intentionally focuses on the changes the Company has made in its forecasting methodologies and its data base since it prepared the forecast approved in EFSC 81-12. The current record shows that the Company has made a number of major and minor changes in the techniques and data it uses to forecast demand in several end-use sectors. These changes include: the development of a new territory-specific population model; refinements to the migration equation in the population model; the use of new appliance-specific price elasticity responses in the residential model; the application of a new end-use model and database to forecast electric demand in the commercial sector; and the use of more territory-specific data for forecasting industrial demand. Following a brief description of the results of the demand forecast, these methodological and data changes will be reviewed and discussed below in the context of the specific components of the Boston Edison's demand forecast methodology.

A. Results of the 1983-1992 Long-Range Forecast

Boston Edison's long-range Forecast covers the time period between 1983 and 2000. In its review of the Forecast, however, the EFSC will limit its evaluation to the time period from 1983 to 1992, since the Council's regulations require electric companies to file forecasts covering a ten-year time frame (EFSC Regulations, Rule 63.4).

4. 7 DOMSC 93 (1982), at 105.
5. 7 DOMSC 93 (1982), at 144.

Boston Edison's Forecast, which was actually run in the fall of 1982, indicates that the Company expects its territory energy sales to grow at a compound annual rate of 1.5 percent from 1982 to 1992. Peak demand, which occurs in the summer in the Boston Edison service area, is predicted to rise at a rate of 1.4 percent a year, compounded annually.

These annual growth rates represent a continuation of Boston Edison's recent history of lowering its estimates of long-run annual growth rates from one forecast to the next (as shown in Table 1). Figures 1 and 2 indicate the trends in projected growth rates for the current forecast and for each previous forecast, along with actual historical energy requirements and peak demand in the Boston Edison service territory. The trends show that the Company has made methodological and data improvements in recent years, leading to smaller variations between actual and projected energy sales and peak loads.[6] The energy forecasts prepared since 1980 have produced relatively stable results, with less than 4 percent difference in their estimates of annual territory energy requirements between 1983 and 1990.

Table 1

Comparison of Ten-Year Compound Annual Growth Rates from Boston Edison Forecasts

Filing	Compound Annual Growth Rates: Peak Demand (%)	Compound Annual Growth Rates: Energy Requirements (%)
1st Forecast (1976)	5.45	3.69
1st Supplement (1977)	4.44	3.41
2nd Supplement (1978)	3.46	3.43
3rd Supplement (1979)	2.88	2.84
4th Supplement (1980)	1.94	1.95
2nd Forecast (1981)	1.71	1.89
1st Supplement (1983)	1.54	1.45

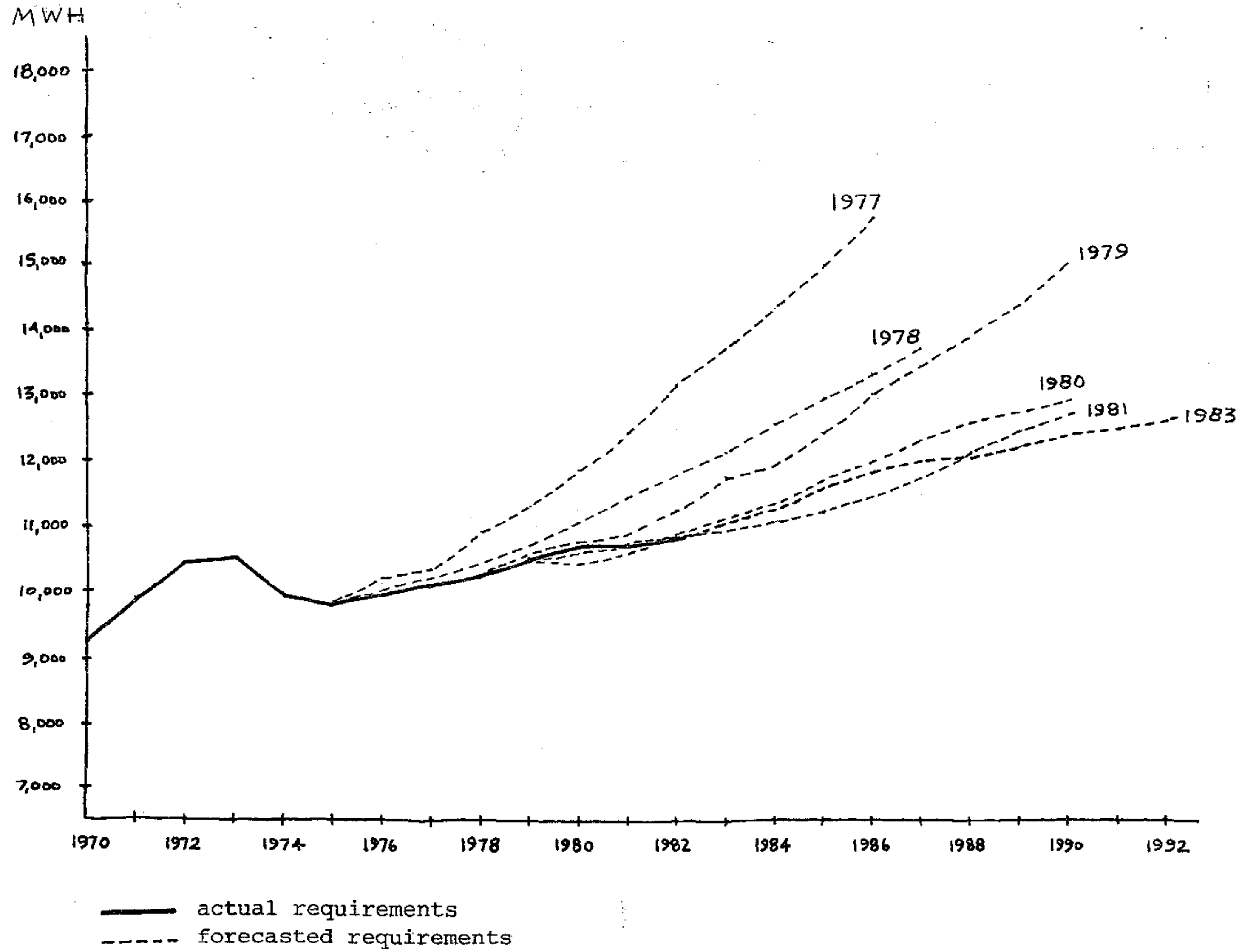
Source: Boston Edison Long-Range Forecasts, EFSC Tables E-8, E-11.

Boston Edison predicts different 1982-92 growth rates for each of its major customer classes. As shown in Table 2 below, sales in the commercial class -- currently the largest sector in terms of sales -- is expected to rise most rapidly at 2.0 percent a year. Residential consumption is forecast to grow at 1.3 percent a year. Industrial sales

6. For a review of the different forecasting methodologies Boston Edison used to produce each annual long-range forecast, see EFSC 81-12, 7 DOMSC 93 at 106-114. This discussion compares the methodological and data improvements Boston Edison made from one forecasting effort to the next.

Figure 1
Boston Edison Company

Trends in Projected Energy Requirements Since
the First Boston Edison Forecast



Sources: Boston Edison Long-Range Forecasts to the EFSC, 1977 to 1983.

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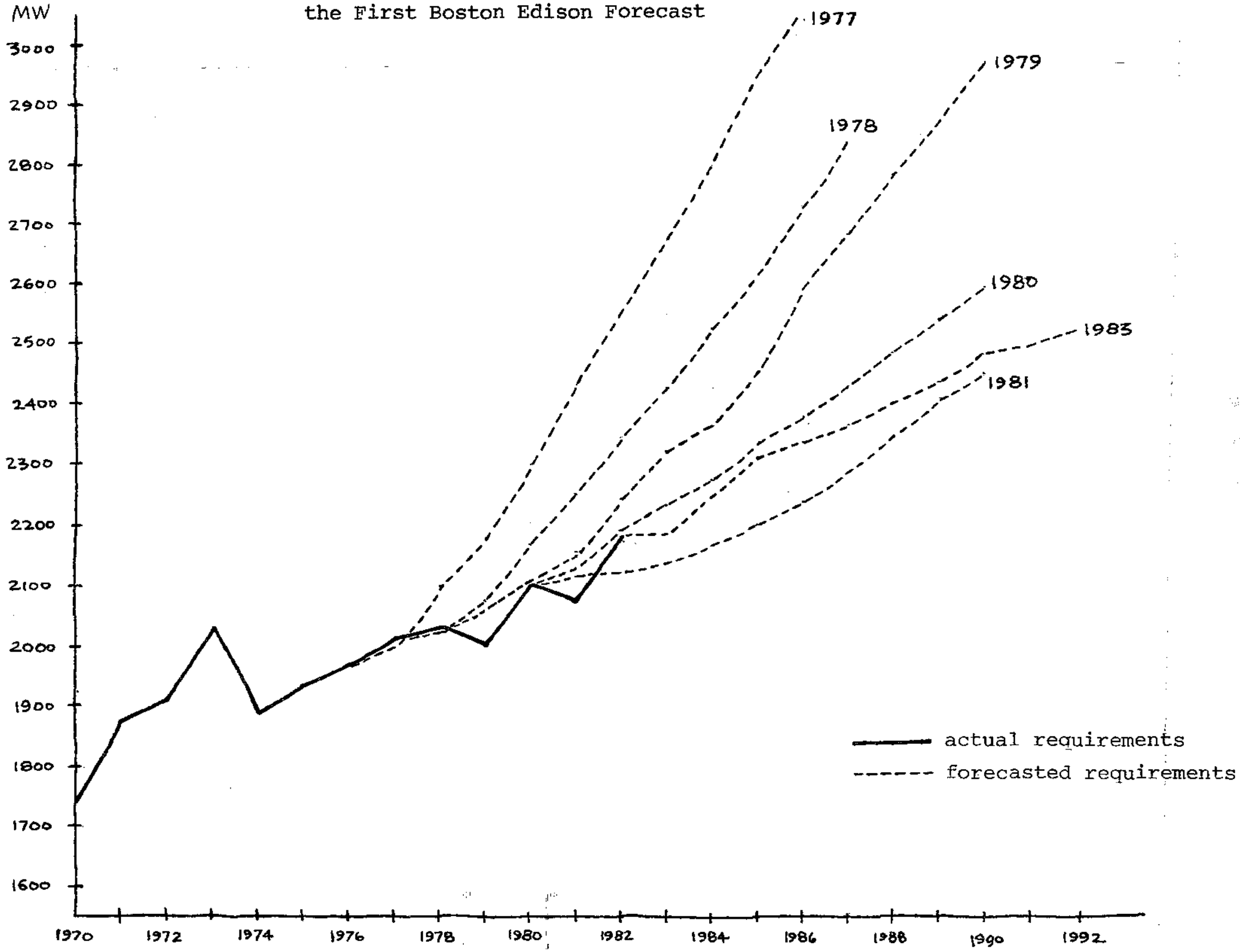
Figure 2
Boston Edison Company

Trends in Projected Summer Peakloads Since the First Boston Edison Forecast



Source: Boston Edison Long-Range Forecasts to the EFSC, 1977 to 1983.

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are estimated to remain relatively flat through the decade, decreasing at 0.04 percent annually. Because of the varied growth rates, commercial sales will represent a large and increasing percentage of total sales over the years, at the same time that residential and industrial sales decline in terms of their share of total sales. Sales to Total Requirements customers are forecast to grow at 1.88% per year. Figure 3 indicates these historical and forecasted shifts in relative sales among customer classes.

Table 2

Boston Edison
1982-1992 Growth Rates for Retail Sectors

Sector	Compound Annual Growth Rate	% of Total Retail Sales 1982 Actual	1992 Forecast
Residential	+ 1.35%	28.0%	26.1%
Commercial	+ 2.03%	52.2%	56.7%
Industrial	- 0.04%	17.5%	14.9%
Streetlighting	0.00%	1.5%	1.1%
Railroad	+ 6.41%	0.8%	1.2%
Total retail sales	+ 1.52%	-	-
Sales to Total Requirements Customers	+ 1.88%	-	-
Territory output requirement	+ 1.54%	-	-

Source: Staff calculations from Boston Edison Long Range Forecast, Table E-8, at H-9.

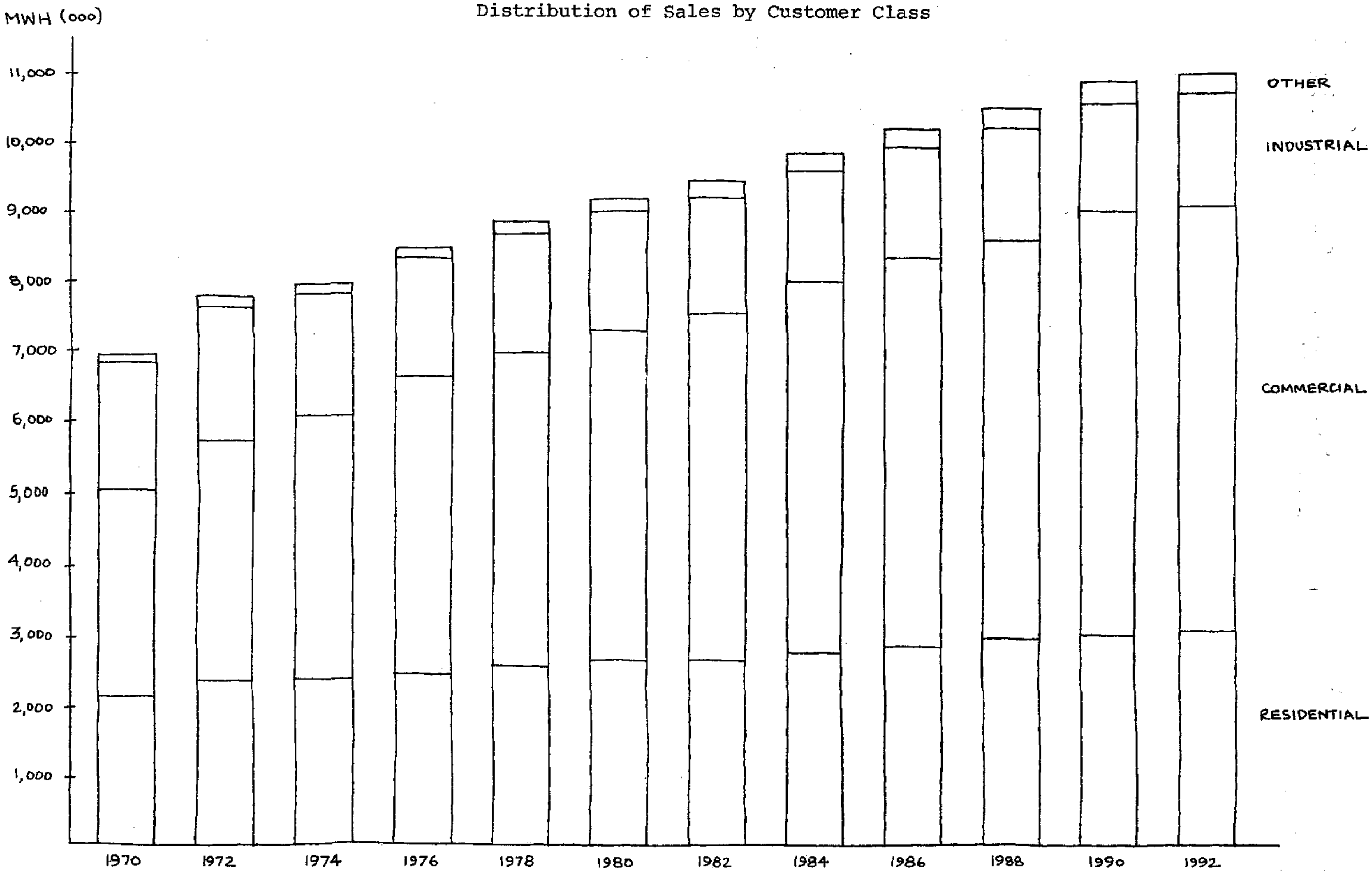
The factors that contribute to these varying growth rates will be discussed individually in the context of reviews of the separate components of the demand forecast. The six components of the Company's methodology that are discussed below are: demographic forecast; residential forecast; commercial forecast; industrial forecast; and price and peak load forecasts.

B. Demographic Forecast

One core feature of any forecast of future electricity use is an estimate of changes in population size that are expected to take place in the period of interest. There are three parts to Boston Edison's methodology for forecasting population changes: (1) a cohort-survival model to estimate natural population changes (i.e., births and deaths from year to year); (2) a migration equation to gauge net flows of individuals in to or out of the Company's service territory each year; and (3) a household-formation model to allocate the population of individuals to households -- the demographic unit required for later development of household electricity usage. These three components are briefly reviewed below.

Figure 3

Boston Edison Company
Total Retail Sales and Percentage
Distribution of Sales by Customer Class



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ource: Boston Edison Long-Range Forecast (1983), Table E-8, adjusted for Information Request SI-37.

This year's population forecast model is entirely new. In the previous filing, Boston Edison used NEPOOL's cohort-survival methodology and computer software to forecast its service territory's population size and number of households, adjusted for net migration (using an equation developed by Boston Edison). In its 1983 decision (7 DOMSC 93 at 114-118), the Council questioned the appropriateness of using NEPOOL demographic data and trends to model population changes in the Company's service territory.

This year, Boston Edison replaced the NEPOOL model with its own cohort-survival model, based on local birth and death statistics, territory-specific fertility trends and survival rates between 1970 and 1980, and national forecasts of birth rates and death rates for different sexes and age groups through the year 2000.

The equation that underlies the Company's model for forecasting population size in any given year is:

$$P_n = P_{n-1} + B + D \pm M$$

where:
P_n = population in year n
P_{n-1} = population in previous year
B = births during previous year
D = deaths during previous year
M = net migration during previous year

The Company built its cohort-survival model on five-year age cohorts using: (1) actual territory-specific data on the number of live births to mothers residing in the Boston Edison service territory; (2) actual historical territory-specific fertility trends for each age cohort; (3) forecasted fertility trends for each age group using U.S. Census Bureau forecasts, adjusted for historical differences between local and national trends for each age cohort; (4) calculated historical death rates, using number of actual deaths in the service territory allocated to age cohorts according to age-specific death rates; and (5) future death rates from Census Bureau forecasts of survival rates for each age cohort for the years 1972, 1976, and 2050. The Company tested the appropriateness of using adjusted national forecasts of birth and survival rates by applying them to the territory's 1970 population data base, using the model to forecast annual births and deaths through 1980, and then comparing the results to actual data on births and deaths in the area. The model performed well.

The cohort-survival technique forecasts natural changes in population size and does not take into account changes due to migration in or out of the region. Boston Edison forecasts net migration through a separate methodology, and then adjusts the natural population forecast to include the impacts of migration.

In the previous filing, the Company forecast migration using a regression equation which used two variables to explain migration: employment growth in the Boston Edison area and U.S. employment growth.

In EFSC 81-12, the Council criticized the Company for using an equation that provided only "a rough proxy for variables that explain the behavior that results in net migration." (7 DOMSC 93 at 116.) The Council encouraged the Company to test other equations that might better capture factors besides economic opportunity that affect migration behavior.

After exploring the use of a variety of variables in single and multiple regression equations, the Company changed its migration equation in the current filing. The new model specification is:

$$M = a + B_o(\text{U.S. LF}) + B_1(\text{Boston CPI}) + B_2(\text{dummy variable})$$

where:

M = Migration
U.S. LF = Change in U.S. Labor Force
Boston CPI = Change in Boston Consumer Price Index
Dummy variable = 1974-1975 data aberrations

Conceptually, this model estimates net migration on the basis of changes in national labor force size and changes in the cost of living in the Boston region. (The dummy variable was used to take out the effects of data aberrations for the years 1974 and 1975.) The Company chose this particular specification over various alternative equations because it performed well statistically and captured the interplay of migration-related factors such as outside opportunities for mobility and the attractiveness of migrating to or from the Boston area.

The Council recognizes the difficulty of estimating inter-regional population movements and commends the Company for its efforts to scrutinize and revise its migration forecast methodology. The Company contracted for a study to identify non-economic variables affecting migration decisions in the Boston metropolitan area, but decided not to include these factors (e.g., religion, residential dissatisfaction, etc.) due to the non-availability of data on them. The Company provided evidence that it chose its final migration equation after testing the explanatory power of various combinations of other economic variables: national, regional and local employment; national, regional and local unemployment; relationships between local CPI and national CPI; and relationships between national and local employment. The Company qualitatively evaluated the results of its migration forecast results through information discussions with local officials, housing experts, and planners in the region.

Therefore, despite our concern over the lack of a strong theoretical basis for the migration equation, we are satisfied that the Company has selected its migration-forecasting methodology through an appropriate and acceptable process that balances theory, data availability, statistical strength, and judgment. Nonetheless, we urge the Company to continue to improve its migration forecast with new sources of data (such as customer hook-up information) and with improvements in its conceptual foundation. Such work is well directed, given that net out-migration has had a greater impact on population levels than natural population changes over the past ten years.

The migration forecast, along with the forecasts of births and deaths, comprise the territory population forecast. The next step in the Company's demographic methodology is to allocate individuals to households. After reviewing the stable historical relationship between household formation trends in the Boston Edison territory and trends in the U.S. as a whole, the Company used an adjusted forecast of U.S. household size for the years 1981 through 1995 to derive estimates of the size of households in the Boston area for those years.[7] From this and the results of the population forecast, the Company projected the number of households in the Company's area each year.

The results of the demographic methodology, shown in Table 3 below, are a 1-percent decrease in total population between 1981 and 1992 (which is equivalent to a -0.09 percent compound annual decline), a slight decrease in household size, and a net annual increase of 0.8 percent in the number of households in the service territory.[8]

Table 3

Boston Edison Demographic Forecast

	population size	household size
1981	1,470,730	589,693
1992	1,456,238	635,412
compound annual change (1981-1992)	-0.09%	+0.78%

The Council commends the Company for its efforts to build its own territory-specific population model, to collect and choose suitable input data, and to test the reasonableness of forecast results through judgment and comparison with Boston-area growth forecasts prepared by others in the region. Moreover, the model is extremely well documented -- something which the previous Company demographic forecast lacked. The new methodology should serve as a strong foundation for residential and commercial demand forecasts in the future. The Council encourages the Company to continue to check the validity of its data with new information sources as they become available.

C. Residential Forecast

Boston Edison estimates that, in 1992, residential energy demand will be 3,028,000 MWH, an increase of 14.4 percent over 1982 consumption. This represents a 1.35-percent compound annual growth

7. In both 1970 and 1980, the average size of a U.S. household was 98.7 percent of the size of an average Boston Edison household. So the Company used this ratio to adjust U.S. Census Bureau projections of U.S. household size through the year 1995. Forecast, at B-11.
8. Ibid., at B-11, B-12.

rate. The new growth estimate is close to what was predicted in the past four residential forecasts.[9]

Most growth in demand is expected to occur among households that use electricity for space heating. The compound annual growth rate for this customer class is 4.05 percent, compared to a 0.64-percent growth rate for basic use residential customers and a 0.8-percent annual increase in the number of households in the Boston Edison service territory.[10] The Company expects space-heating sales to increase due to the addition of new heating customers, rather than higher average use per customer. Because of so much growth among these customers, sales by heating customers is forecast to account for 24 percent of total residential sales in 1992, compared to 18 percent in 1982.

The technique the Company uses to forecast residential consumption is an end-use methodology, quite similar to the one it used in its previous filing. An end-use model attempts to forecast KWH consumption by estimating the number and usage of all electricity-consuming "end-uses," or appliances, existing in a particular sector. In its particular adaptation of the technique, Boston Edison applies estimates of appliance-specific saturation trends to the forecast of households to obtain estimates of how many of each of 20 different appliances will be owned by residential customers in each of the forecast years.[11] Additionally, the Company forecasts annual electricity usage levels for each appliance, based on a baseline usage level adjusted for short-run and long-run price elasticities. The Company calculates annual appliance usage for each forecast year by multiplying each appliance's estimated usage for that year by the estimated number of appliances owned by residential customers that year, then summing usage across all 20 appliances.

In its previous Boston Edison decision, the Council generally applauded Boston Edison's "sophisticated and credible demand forecasting methodology" (7 DOMSC 93 at 144), of which the "residential class sub-model is the most complex forecast methodology" (7 DOMSC 93 at 128). The Council did not direct any specific criticisms toward the end-use approach adopted by the Company. The Council did, however, cite numerous criticisms having to do with the appropriateness and reliability of the data Boston Edison used in its past filing. Overall, the Council questioned the Company's overreliance on state and national data sources for key input variables, such as the estimate of households, the appliance saturation trends, and appliance usage levels (7 DOMSC 93 at 128-131).

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9. See the previous four Boston Edison forecasts, Table E-2A.
10. See: <u>Forecast</u>, Exh. B-24 (p.B-39), and EFSC Tables E-1 and E-2.
11. Actually, only 16 appliances are forecast using appliance saturations; the remaining 4 appliances are forecast using different techniques.

In its current filing, Boston Edison has made numerous data changes that address past Council concerns. In particular, the Company has developed its own territory-specific forecast of households (previously described), new appliance ownership data (based on a 1980 customer survey), and new appliance-specific income/saturation equations. The Council commends the Company for taking steps to ameliorate shortcomings in past forecasting approaches.

The 1980 Boston Edison Appliance Survey of over 8600 residential customers concerned itself with the characteristics of customers and their homes, the types of appliances they own, their plans to add or replace appliances, and their current conservation efforts.[12] The responses of approximately 4300 customers provided income and appliance ownership data that the Company used to construct separate regression equations for 16 different appliances to describe the relationship of appliance ownership to household income.[13] The saturations obtained from this method seem reasonable in that appliances that could be considered as "necessities" were characterized by rapidly increasing saturations even at low income levels, while "luxury" appliances produced low saturations for all but the higher income levels.

Boston Edison used these income/appliance saturation functions along with 1979 U.S. Census Bureau data on income in the Boston Edison territory and a forecast of real personal income growth rates (prepared in 1982 by Wharton Econometric Forecasting Associates), to estimate future appliance saturations in the Boston Edison territory. As a check on this method, the Company compared 1980-derived saturations and the saturation results from the 1980 Appliance Survey, and reviewed outside qualitative reports of future trends in appliance sales in the U.S. Both comparisons indicated that the Company's income/saturation functions performed reasonably well.[14]

The Council is pleased that Boston Edison has taken advantage of local sources of information for use in this residential forecast. Together with the detailed documentation of the methodology and data sources it uses in its residential sub-model, these efforts go a long way to strengthen the Company's Forecast.

12. See Information Request SI-3: Boston Edison "1980 Appliance Survey of Residential Customers."
13. See Table 4 for a list of these 16 appliances. The Company used different techniques to forecast future ownership or usage for the other 3 appliances in the end-use technique. Data on the most important of these remaining appliances, electric space heating, was obtained from 5 years of actual customer hook-up records (from which the Company took an average penetration rate for new homes and for apartments) and from 1971-1981 Company records on actual use by space-heating customers (with usage levels adjusted for price increases).
14. See: Forecast, at C-34.

There is one variable, however, for which the data remain largely unchanged from the last filing to the present one. The Company is still using old, national estimates of appliance energy usage for many major electric appliances. Table 5 below indicates the source of usage estimates for each of the appliances individually forecast in the Boston Edison methodology.[15] The usage estimates of 10 of the appliances, which accounted for over half of residential demand in 1982, were derived from Edison Electric Institute (EEI) data described by the Company as follows:

> The EEI appliance energy use estimates referenced in the forecast represent data EEI collected from various utilities across the United States.... These figures represent national averages. They are accepted estimates that have been used in the utility industry for 40 years....The appliance estimates cited as being 1971 EEI data represent information collected from studies done prior to and including 1970.[16]

Boston Edison adjusts these old, national usage estimates with short-run and long-run price elasticities to attempt to take into account the cumulative effects of annual changes in the price of electricity and post-1971 improvements in appliance efficiency. Similarly, it forecasts future annual appliance usage through these same short-run and long-run elasticities.

Boston Edison developed these elasticity factors in a previous filing (1979 Forecast), and provides in the current forecast a clear description of how these elasticities affect appliance usage over time.[17] The following equation summarizes how price elasticities affect the KWH usage forecast:

$$D = U * P_i * [-0.239 + [-0.761 * (N/R)]]$$

Where:

D = cumulative short- and long-run price effects
U = 1971 EEI usage data
P = electricity price change (year i-1 to year i)
i = year
N = number of years the elasticity has had to take effect, from 0 to 10 (for price increase) or 0 to 20 (for price decrease)
R = 10 for price increase; 20 for price decrease

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15. Electric range (regular and self-cleaning), refrigerator (frost-free, manual, second), freezer (frost-free, manual), dishwasher, clothes washer, and clothes dryer. Total usage for these 10 appliance equals 55.9 percent of total 1982 residential consumption. See Table 4.
16. Staff Information Request, R-1.
17. See: Forecast, at C-2 to C-8.

Table 4

Boston Edison Residential Appliance Usage Estimates

	Source of Information	Vintage of Information	Estimated KWH Usage 1971	1982	Percent of Total Residential Demand[b]
Electric Range[a]	EEI	1971	1190	1066	6.8
Electric Range[a] (Self Clean)	EEI	1971	1190	1094	3.1
Refrigerator-frost free[a]	EEI	1971	1829	1660	19.5
Refrigerator-standard[a]	EEI	1971	1137	1032	9.0
Refrigerator-second[a]	EEI	1971	1137	1032	2.6
Freezer-frost free[a]	EEI	1971	1761	1598	1.5
Freezer-standard[a]	EEI	1971	1195	1085	3.5
Dishwasher[a]	EEI	1971	363	329	2.9
Room Air-Conditioner[a]	BECo; Aham; EEI	1981;1971;1979	760	296	2.7
Central Air-Conditioner[a]	BECo; Aham; EEI	1978;1971;1979	1792	699	0.5
Clothes Washer[a]	EEI	1971	103	93	1.4
Clothes Dryer[a]	EEI	1971	993	901	5.6
Water Heater[a]	c	c	c	3969	10.3
Microwave Oven[a]	EEI	"recent"	c	100	0.2
T.V.-Color[a]	EEI	1979	c	320	5.1
T.V.-Black/White[a]	EEI	1979	c	100	1.4
Electric Space Heating	EEI	1971-81	c	4475 Apts. 11015 - SF	10.8
Quartz Heater	c	c	c	480	3.8
Lighting & Misc.	BECo (residual use)	c	c	783	9.3

a Appliance for which Boston Edison developed income/saturation functions from data in 1980 Appliance Survey.

b Calculated by figuring 1982 total usage per appliance (% of appliances x KWH per appliance), and then dividing that appliance's total usage by total 1982 residential consumption (2,647,200 MWH). Sources: Forecast, pp. C-35, C-36, C-40, C-41, C-44, EFSC Table E-2A.

c Not presented on this record.

According to Boston Edison's model, short-run impacts (-0.239) take effect one year following a price increase or decrease. Long-run effects start to be felt two full years after a price change. The entire impact of a price increase takes 10 years to complete, while it takes 20 years to feel the full impact of a price decrease. Over the course of a decade, as from 1971 to 1981, the short-run and long-run effects of each year's price changes are cumulative.

The results of using the equation with actual 1971-to-1981 price changes and 1971 EEI usage levels mean that there have been relatively small decreases in estimated appliance usage levels from 1971 to 1981 (see Table 4). This happens because of the combination of a few large price increases and many small price decreases that occurred in the past decade. From the 1982-1992 period, the Company forecasts an overall trend towards reduced appliance usage, which is the net result of anticipated price decreases in the early years and small price increases in the later years of the forecast period.

The Company believes that the results are reasonable, given the lack of federal appliance efficiency standards, the market demand for more efficient appliances, and the significant strides made in recent years by the appliance industry to improve the efficiency of new appliances sold. On the other hand, the Company is aware of data showing that, by 1981, new appliances such as refrigerators, clothes washers, and dishwashers, had become from 45 to 59 percent more efficient than similar appliances produced in 1972.[18] Because of this trend, and because of the Company's expectation of increased saturation rates and increased number of households in the service territory, we question whether the impacts of improved appliance design might be infiltrating the market faster than is captured by the Company's 1971 base usage estimate adjusted for short-run and long-run price elasticities. The Council reiterates its criticisms of EFSC No. 81-12 relating to the Company's reliance on EEI data (7 DOMSC 93 at 129-131) and hereby ORDERS the Company to investigate the continued appropriateness of using the 1971 (and older) EEI data as the basis for forecasting post-1983 usage estimates. This seems particularly critical since the 10 appliances forecast using these data represent a large proportion of residential consumption, and errors in these appliance usage estimates could directly affect the total estimate of residential demand.[19] This issue is addressed in Condition 1 to this Decision and Order.

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18. Forecast, p. C-7.
19. For example, a 10-percent error (plus or minus) in forecasting KWH usage by frost-free refrigerators could mean a difference of nearly 2 percent (+ or -) in the forecast of total residential energy consumption. Since frost-free refrigerators account for nearly 20 percent of total residential consumption, errors here could make a difference. If their 1982 usage was actually 1500 KWH rather than 1660 KWH (as Boston Edison estimates), and all other data and variables remained the same, it could mean a difference of 49,844 MWH in the overall residential forecast, or 1.9 percent less residential demand.

Clearly, Boston Edison is moving in the direction of using more current and more local data as inputs to the residential sub-model. Table 4 shows that the Company has begun to make use of Company billing records at least to estimate electric space heating and air-conditioning usage[20] and to use 1979 industry data for televisions and microwaves. The Council commends the Company for taking these steps.

The Council sees several additional strengths and one additional shortcoming in Boston Edison's residential forecast that are worth mentioning here.

The residential submodel represents an extremely well-documented demand forecast, which indicates a willingness and ability of the Company to respond to past Council concerns and criticisms. The Council recognizes the evolutionary process of forecast preparation, review and refinement, and notes the Company's progress in developing an appropriate, highly reviewable and reliable demand forecast.

The Company indicates its intention to continue to collect and analyze territory-specific data on appliances and equipment used in the residential sector. Specifically, the Company intends to analyze internal customer billing and hook-up data, and to conduct a 1983 residential survey to address, among other things, the role of supplemental heating appliances in the residential sector.[21] The Council commends the Company for these continuing efforts to supplement, refine and update key data inputs to its residential submodel. These efforts should take place in tandem with steps to evaluate the appropriateness of using old EEI data on appliance consumption and to investigate the availability and feasibility of using alternative sources of appliance use estimates in compliance with Condition 1 to this Decision and Order.

Finally, the Council sees one major inconsistency in the residential demand forecast; it is, as the Company describes, a "'natural increase' prediction. In other words, the forecasted sales are exclusive of modifications from any conservation and load management programs in IMPACT 2000."[22]

"IMPACT 2000 - An Energy Plan to the Year 2000" is a program initially proposed by Boston Edison in 1982 with the purpose of reducing the Company's oil dependency through coal conversions and Company-sponsored customer conservation and load-management activities. The Company began to implement the conservation and load-management portion of IMPACT 2000 in 1983. Many of these programs are targetted to residential customers and could lead to first-year electricity savings in the residential sector of approximately 3,000 MWH.[23]

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20. It is unclear what sources were used to forecast water heating or quartz heater usage levels.
21. See Staff Information Request SI-5.
22. Forecast, Introduction and Summary Section, first page (unnumbered).
23. This is the Company's estimate of savings. See IMPACT 2000 (October 31, 1982), Exh. B., at ADM1-I17.

While these estimated savings are relatively small -- representing only 0.1 percent of estimated 1983 residential demand -- they could mean a reduction in the 1983-84 growth rate from 2.95 percent ("natural forecast") to 2.83 percent (forecast adjusted for IMPACT 2000 conservation programs).[24] The Company's omission from its forecast of the conservation impacts of a program to which it has publicly committed itself[25] and which it has already begun to implement, represents, at a minimum, an inconsistent Company policy towards demand management. The decision to exclude savings that could result from Company-sponsored conservation programs -- and to include only market-driven conservation through price-elasticity adjustments built from pre-1970 data -- seems to somewhat undermine the credibility of the Company's commitment to sponsor conservation programs for its customers.

The Council has in the past stated its support for utilities' consideration and use of demand-management strategies as full components of a comprehensive demand-forecasting and supply-planning process.[26] In fact, the Council specifically raised its general concern about such issues in the past Boston Edison decision (7 DOMSC 93 at 160-162). Given this recorded position and given that the Company has already invested resources in implementing a conservation program in the residential sector, the Council can not condone the Company's reticence to integrate conservation from IMPACT 2000 programs into its long-range forecast of demand. Certainly, any actual KWh savings that flow from Company-sponsored programs will be felt for years to come and will affect the Company's need to supply energy and capacity in future years.

These comments should not be interpreted as putting the Council's stamp of approval on initial estimates of KWh savings from an untested program. The Council wants to see Boston Edison collect and analyze information on customer responses to individual Company-sponsored programs and on the KWh savings associated with each one. Such efforts would serve to enhance the reliability and usefulness of the Company's KWh savings estimates and its overall forecast of demand.

The Council's intent in raising this issue is to underscore its belief in the potential importance of cost-effective conservation and load management programs to the Company's ability to provide least-cost, reliable electric supply in the years to come. The Council therefore CONDITIONS the Company that its future demand forecasts reflect the impact of Company--sponsored conservation and load management programs. (See the Conclusion, Section II.G, and Section III. C, <u>infra</u>, for this Condition.)

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24. Calculated from <u>Forecast</u>, EFSC Table E-2A.
25. See Massachusetts DPU Docket No. 1350.
26. <u>In Re NEES</u>, 7 DOMSC 270 (1982), at 309-310; <u>In Re EUA</u>, 5 DOMSC 10 (1980), at 33; <u>In Re Northeast Utilities</u>, 8 DOMSC 62 (1982), at 127-132; and <u>In Re Com/ELectric</u>, 9 DOMSC 222 (1983), at 283.

D. Commercial Forecast

The Company predicts that its commercial sales will grow from 4,932,000 MWH in 1982 to 6,031,000 MWH in 1992. This represents a compound annual growth rate of 2.03 percent (1982-92) and makes the commercial sector the fastest growing of Boston Edison's major sectors. The commercial sector is also the largest, comprising 49.6 percent of total territory sales in 1982. By 1992, these sales are forecast to account for 52.1 percent of total territory sales.

Boston Edison forecasts that the fastest growing subsectors of the commercial class will be retail/wholesale customers (with growth of 3.2 percent a year) and public office buildings (3.3 percent annual growth), both of whose space heating consumption is predicted to rise approximately 10 percent a year. Lighting end uses now account for the largest share of total commercial sales (44 percent), but they are expected to represent only 31 percent in 1992 due to faster growth of other end uses (such as space heating, cooling, and water heating). Overall, space heating is expected to be the fastest growing end use at 6.9 percent annually, and it will account for a fourth of all energy consumption in the commercial sector in 1992.

The large size and expected growth of this sector make it particularly important that Boston Edison carefully understand the nature of its commercial customers' demand for electricity. The Company apparently recognizes the significance of the commercial forecast and has adopted in this filing an entirely new, state-of-the-art methodology.

In the previous forecast (EFSC 81-12), Boston Edison used a single-equation econometric model to predict commercial demand. The model was based on the assumption that commercial demand for electric energy is related to the level of economic activity in the service territory, reflected by the number of households, the average real price of electricity, and the previous year's commercial electricity sales. While the Council commended Boston Edison in 7 DOMSC 93 (at 131) for the reviewability of the commercial sector forecast, the Council found the methodology problematic for several reasons. The model specification that included lagged commercial sales was more appropriate for short-run forecasts rather than for a long-run forecast. The model utilized highly aggregated data that combined different types of commercial buildings and different end uses of energy. Therefore, the model did not capture potential changes in the structure of the commercial sector's use of energy. The Council concluded that the "development of any forecasting methodology should begin with information about the structure, variable interrelationships, and the dynamics of the system being modeled." (7 DOMSC 93 at 133.)

The Company's new commercial forecasting methodology responsibly addresses the full array of concerns raised in the past Council decision. The new methodology is a version of a model developed by Jerry Jackson in the mid-seventies for Oak Ridge National Lab.[27] It is

27. The original model was designed to forecast national commercial energy demand. The model has been adapted to make it suitable for a single utility service territory.

a disaggregated end-use model, designed -- like the previous Boston Edison model -- on the assumption that the demand for electric energy by commercial customers is a function of economic activity in the commercial sector. But, the new model contains a detailed mechanism for capturing potential changes in the structure of the commercial sector's use of energy.

The Commercial Energy Demand Model ("CEDM"), as it is called, can be viewed as having two major components: a set of equations that estimate the stock of energy-using capital equipment in any given time period, and a set of equations that estimate the utilization of energy by that stock of equipment during the time period.

The stock of energy-using capital equipment is forecasted based on forecasts of existing and new commercial floor space, on saturation rates of energy-using capital equipment in existing commercial buildings, and on penetration rates of energy-using capital equipement into new commercial floor space. In turn, the forecast of existing floor space is based on a base year inventory of floor space and an estimate of future market removal rates for building of different ages. The forecast of new floor space is based on a balance between supply (existing floor space) and demand (based on forecasts of employment and floor space per employee). Equipment saturation rates are based on historical data.

The utilization rates of capital equipment are forecast based on equipment cost and efficiency relationships, which balance maximum equipment energy usage rates, actual usage rates of equipment by consumers, forecasts of fuel prices, and estimates of the price elasticities that drive consumer choices. The model uses short-run elasticities to drive customer short-term decisions on the intensity of usage of the capital equipment, and uses long-run elasticities to model consumer equipment-purchase decisions in new floor space.

Forecasts of total capital stock and utilization factors are prepared for six types of commercial buildings, five types of energy-using equipment (or end-uses), and four types of fuel. A one-year forecast of commercial energy demand for a given building type (e.g., office), end-use (e.g., cooling), and fuel (e.g., electricity), is produced using the equation defined in Figure 4. Total commercial electricity demand is then just the sum of the estimates of the electricity demand for each end-use in each building type.[28]

Figure 5 summarizes the various components and sub-components of the CEDM model.

The new approach is conceptually similar to the one Boston Edison uses in its combined demographic/residential models. Within a given year, in both the residential and the commercial models, the number of end uses (e.g., household appliances or commercial capital equipment) changes incrementally, and demand depends on the rate at which this equipment or stock uses energy. In the long run, both models consider

28. Boston Edison forecasts electricity sales to the MBTA separately.

Figure 4
Boston Edison Commercial Energy Demand Model

Equation for a one-year forecast for a given end-use, fuel type, and commercial subsector

Utilization Factor	Stock of Energy-Using Capital

$$Q_{T,k,b,i} = \sum_{t=0}^{t=T-1} \left[\underbrace{U(P_T)_{t,k,i}}_{\text{Utilization Factor}} * \underbrace{E_{t,k,i} * F_{t,k,i} * (A_{t,b} * d(T-t))}_{\text{Stock of Energy-Using Capital}} \right]$$

where:

Q = commercial energy demand (MWh/year)

T = forecast year

k = type of end-use equipment (space heating, space cooling, water heating, lighting, other)

b = type of building/commercial subsector (office, retail/ wholesale trade, education, health, public, other)

i = type of fuel (electricity, natural gas, oil, or other)

t = year in which floor space was added to the commercial market (where t=0 is the floor space of oldest vintage, and where T-t is the floor space added during the year before the forecast year).

U = rate at which equipment is used

P = price of energy ($/MWh)

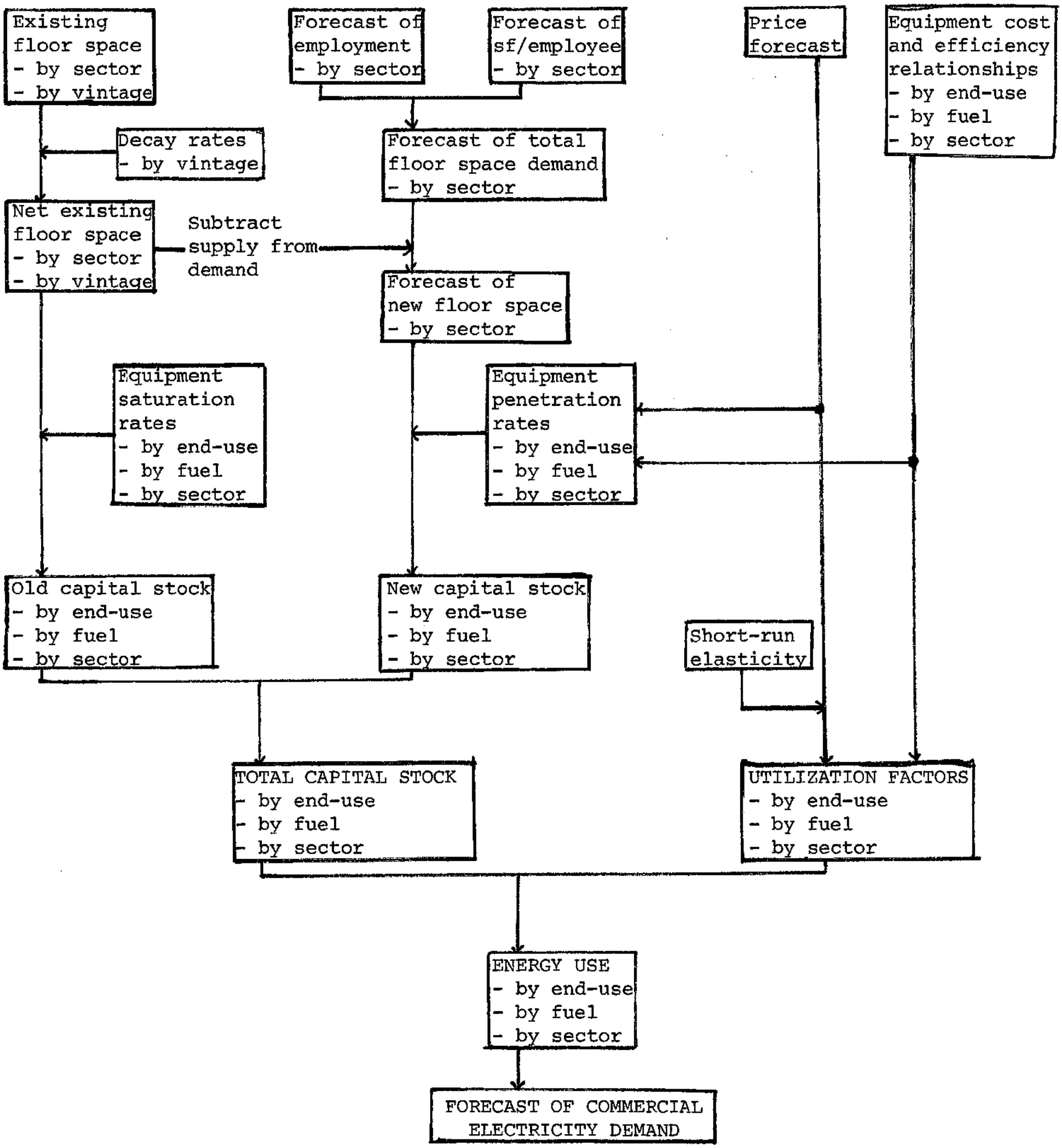
E = maximum potential energy requirement of equipment

F = penetration rate of equipment (or percentage of floor space of vintage t served by particular equipment)

A = gross additions of commercial floor space

d = decay rate, or, percentage of floor space of vintage t that is still standing in year T

Figure 5
Boston Edison - Commercial Energy Demand Model Structure



changes in the stock of end uses (i.e., changes in the number of households or in the saturation rates for the residential forecast, or changes in the net amount of floor space and penetration rates for capital equipment among commercial users) and changes in the energy-using characteristics of end-use equipment (e.g., changes in their energy efficiency).

The CEDM has enormous data requirements. It requires disaggregated data for a base year (Boston Edison uses 1981) on: stock of existing floor space (broken down by vintage and by six different types of buildings); and end-use equipment saturations, penetrations and usage levels for five different types of equipment and four types of fuel. Additionally, it requires historical information on commercial sales, and historical and forecasted data on employment and fuel prices.

Boston Edison has undertaken a serious effort to locate and adopt the most reliable local sources of data it could find to date. The set of data used in the first CEDM forecast is drawn from a variety of sources, including Company records, territory-specific information from state and local organizations, and state-level data from various sources. Table 5 indicates the data sources the Company used for each variable in the Commercial Energy Demand Model. As the information in this table suggests, Boston Edison has well-documented its use of data and information sources, just as it has provided an adequately detailed description of the model's complex structure.

Data on many key variables, including commercial employment, office building floor space, end-use equipment saturations and electricity prices, are territory specific and come from Boston Edison's own records and from outside sources within the region. However, several other important variables, such as retail floor space, age distribution of all commercial office space, energy usage intensities, and price elasticities, all utilize state-level or non-territory-specific data. The data used for some of these variables show them to be important enough in terms of their relative size to significantly affect the outcome of the total forecast. In some cases, the Company judged the reasonableness of non-local data and estimates derived from them by checking them against alternative (but in most cases incomplete or unpublished) local sources, such as Company data or the judgment of local individuals or organizations knowledgeable about trends in the different subsectors of the commercial sector. Given these efforts and the Company's success in obtaining territory-specific data for other key variables, the Council commends the Company for equiping its new commercial forecasting model with what appears to be a reasonable start-up data base. It is important to note that the data requirements of a newly developed or adopted disaggregated end-use model pose significant start-up challenges, and that Boston Edison has met these challenges more than adequately in its initial, major application of the CEDM to this EFSC filing.

The CEDM methodology is relatively new and has been tested in only a few utility service territories. It is, of course, entirely new to Boston Edison. The continued challenge for the Company will be to monitor the performance of the model (especially in its forecasts for the six different commercial subsectors), to evaluate the continued appropriateness of its use of non-local data or certain

Table 5

Sources of Data
Boston Edison Commercial Energy Demand Model

VARIABLE	CATEGORY	SOURCE(S) OF DATA
Commercial KWH Sales - Base Year	SIC-coded	Boston Edison (BECO) Sales Data (1981).
Commercial Employment-Historical	SIC-coded	Massachusetts Division of Employment Security (DES) data for BECo areas (1967-1979); for public sector, Data Resources, Inc. data (1979, backcast to 1967).
Commercial Employment BECo/State Ratio	SIC-coded	DES data (1979), used to derive BECo floor space data from state floor space data for education, retail/wholesale, other sectors.
Commercial Employment Forecast	SIC-coded	Wharton Econometic Forecasting Associates' forecast of Gross National Product used with Federal Reserve Bank of Boston's data on Gross State Product to forecast Gross State Product (by SIC), which was used with DES data to forecast BECo commercial employment (by SIC).
Commercial Floor Space - Base Year Existing Stock	Office Bldg. (SIC 60-67)	Building Owners and Managers Association of Greater Boston (BOMA) data on Boston metropolitan area (1981).
	Public (SIC 90-93)	New York State Energy Office Study of state-level floor space (1980).
	Retail/wholesale (SIC 50-54)	Charles River Associates (CRA) study of state-level floor space (1980).
	Health (SIC 80)	CRA state data (1980), adjusted judgmentally for BECo area (1980).
	Education (SIC 82)	Xenergy study of state floor space (1979).
	Other (Misc. SIC's)	Xenergy study of state floor space (1979).
Commercial Floor Space - Age Distribution of Existing Stock	type of building (sector)	CRA estimates of age distribution of state's commercial floor space (1980).

Table 5 continued

VARIABLE	CATEGORY	SOURCE(S) OF DATA
Floor Space per Commercial Employee	type of building (sector)	BECo floor space estimate - DES employment data for BECo area
End-Use Equipment - Saturations	Space Heating Water Heating	BECo Survey of Commercial/Industry Customers (1981), adjusted with other Company data.
	Electromechanical Lighting	BECo assumption of 100% saturation.
End-Use Equipment - Penetrations	Space Heating	BECo sales data
	Air Conditioning Water Heating Electromechanical Lighting	Internal model equipment and fuel-choice algorithms.
End-Use Equipment - Energy Usage Intensities	Water Heating Electromechanical Lighting	Xenergy data (1979) and CRA data (1980).
	Space Heating Air Conditioning	Estimates of residual commercial usage, in base year (based on calculations of total floor space & saturation of other end-uses and usage of other end-uses).
Commercial Electricity Price	Historical	BECo revenue and sales data (1970-1981) converted to 1975$ with GNP deflator.
	Forecast	BECo initial estimate of commercial revenue requirements and sales yield commercial electricity price estimates, then deflated to 1975$ using GNP deflator estimate prepared by Wharton National Econometric Model (1982).
Commercial Price Elasticities	Short-run Long-run	BECo literature review and analysis of historical price changes and sales (1979).

Source: Forecast, at D-3, D-12; Information Requests SI-7, SI-10, SI-11, SI-13.

parameters[29] for key variables, and to locate (or develop) local data and new parameters where needed. These efforts are needed in all sectors of the Boston Edison forecast, to be sure, but they are particularly critical in the commercial sector, given its currently large size and its expected growth over the next decade. It will be especially important to see how well the model picks up the impact of changes in the structure of the commercial sector, should they occur in the years ahead. The fact that this end-use model can shed information on these changes is, of course, one more reason why the Council commends Boston Edison for its adoption of its new commercial methodology.

The Council sees other potential strengths of the CEDM, including its ability to simulate interfuel substitutions, its ability to incorporate changes in the engineering efficiencies of equipment, and its capability to perform analyses to estimate the sensitivity of the forecast to changes in key assumption (e.g., faster-than-expected growth in commercial employment, slower-than-expected growth in office-building floor space, or alternative oil price forecasts). Boston Edison apparently has not yet used the model in this latter capacity, but the Council strongly urges the Company to do so. It would enable the Company to obtain yet another form of a check on the reasonableness of using certain data. It could offer the Company a means to analyze the impacts of changes in the commercial energy-using system, including changes in energy utilization or efficiency fostered by Company-sponsored conservation initiatives. And, at the very least, it could help the Company better quantify the commercial sector's contribution to the uncertainties that surround the Company's total forecast of territory energy requirements.

The Council views the Company's implementation of the CEDM as a major step forward in its demand forecasting effort -- a step that is appropriate to the resources of the Company and to the importance of the commercial sector in the Boston Edison service territory. The Council commends the Company for this commitment and encourages the Company to continue to invest resources in carefully tracking the performance of this model and in supporting further data-acquisition and analytic efforts that take advantage of the full potential of the model's capability.

E. Industrial Forecast

Boston Edison expects little change in total energy consumed by industrial customers between 1982 and 1992. In 1982, industrial consumers used 1,651,000 MWH, or 17.5 percent of total retail electric sales. In 1992, the Company forecasts industrial usage to decline by 0.04 percent a year to a level of 1,645,000 MWH, representing only 15 percent of total retail sales. Boston Edison expects that some SIC groups will experience growth in electric demand while others will decline. The fastest-growing industrial subgroups are expected to be: non-electric machinery (SIC 35), at 5.3 percent a year; electric

29. For example, Boston Edison assumed constant estimates of square-footage-per employee for each commercial subsector for the entire 1982-to-1992 forecast period.

machinery (SIC 35), at 2.2 percent a year; pulp and paper products (SIC 26) and printing and publishing (SIC 27), both at 2.0 percent annually; and instruments (SIC 38) at 1.5 percent a year. These five groups accounted for 64 percent of total industrial sales in 1982, and will represent 70 percent in 1992.

These estimates were derived from a methodology that differs in several ways from the one the Company used in the previous filing. In that forecast, Boston Edison combined the results of several econometric models to estimate demand for energy by individual SIC subgroups. The Council commended the Company for preparing a well-documented and reliable model, but raised several concerns regarding the Company's approach. These problems included: lack of evidence for sufficient theoretical grounding in the design of the econometric models; potential inappropriateness of several of the data inputs (e.g., NEPOOL energy intensity forecasts); problematic and potentially invalid model adjustments; and weak statistical performance of many of the model specifications. The Council concluded that:

> Models based on theoretical assumptions about how particular industries will fare in the service territory in relationship to variables such as military expenditures and energy prices would make the Council more confident in the industrial forecast than equations with better statistical results, but weaker theoretical bases. The Company needs to strengthen the theoretical (i.e., intuitive) basis for its industrial model.[30]

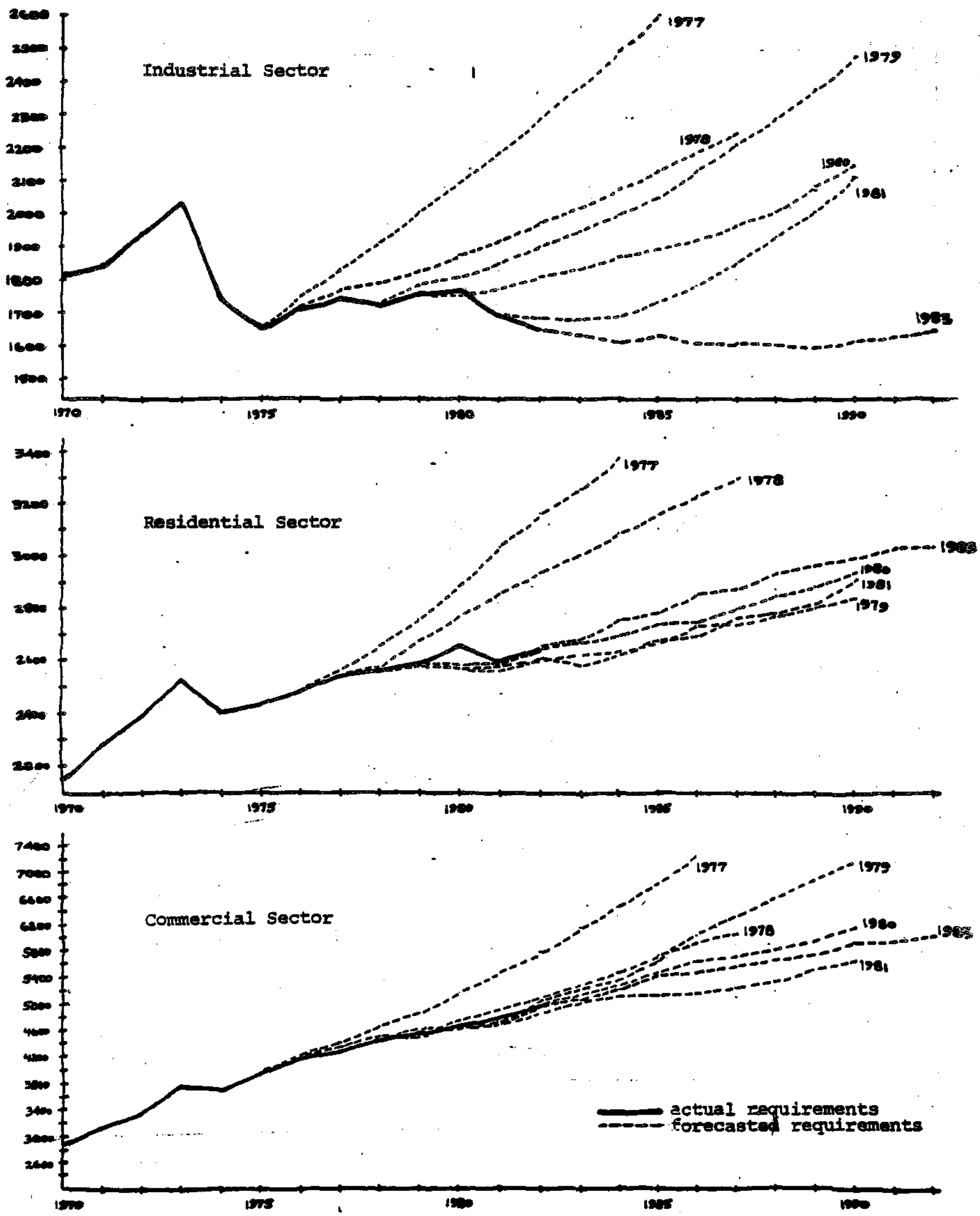
The Council acknowledges that industrial sector consumption is perhaps the most volatile and difficult to predict. The sector's composition is undergoing change and is responsive to macro-economic factors which are in themselves difficult to forecast. Boston Edison's own industrial forecasts of the past few years have shown considerably more variation and relative error than the Company's estimates for either residential or commercial sales. (See Figure 6, which compares the track records for each sector's forecast in recent years against actual sales.)

The Council thus recognizes the difficulty of providing a reliable industrial sales forecast and notes in this regard the Company's attempts to take steps to improve the quality of its industrial forecast results by changing its industrial methodology. In the current filing, Boston Edison still uses different regression equations for individual industrial groups, but it has attempted to choose model specifications and data that are more appropriate to the particular energy-consuming behavior of various industrial subgroups.

The industrial forecast assumes that the electric demand of each of 19 different industrial subgroups (disaggregated by two-digit SIC codes) is a function of some combination of Gross National Product, employment, electricity price, and lagged industrial sales. Each subgroup's consumption is forecast with a different simple or multiple regression equation, as shown in Figure 7.

30. 7 DOMSC 93 at 136.

Figure 6
Comparison of Current and Past Boston Edison
Forecasts for the Industrial, Commercial and Residential Sectors



Source: Forecasts (1976 through 1983), EFSC Tables E2A, E3, E5.

Figure 7
Boston Edison Industrial Energy Forecast Equations

Method	Equation	SIC's forecast with equation	% of 1982 Sales	Company Rationale for Utilizing Equation for SIC's
1	$MWH = a+b_1\underset{\text{Sales}}{(\text{lagged})}+B_2(\text{price})$	20 - food 24 - lumber and wood 37 - transport equipment 39 - misc.	9.5 0.2 5.8 0.4	These are small, old, energy-intensive industrial where past investment in capital equipment and price of electricity affect use.
2	$MWH = a+b_1(\text{employment})+B_2(\text{price})$	23 - apparel 28 - chemical 30 - rubber 31 - leather 33 - primary metals 34 - fabricated metals	1.0 4.2 4.8 0.7 1.4 4.8	These are small, energy-intensive industries where energy use is related to overall growth in the industry and price or electricity.
3	$MWH = a+b_1(\text{lagged sales})$	22 - textiles 32 - stone, clay, glass	1.4 1.3	These are small, energy-intensive industries with fixed capital affecting consumption.
4	$MWH = a+b_1(\text{GNP})+B_2(\text{employment})$	35 - non-electric machinery	14.2	This is a large, fast-growing, electricity-intensive industry (including computers) with a strong national market, not greatly affected by price.
5	$MWH = a+b_1(\text{price})+B_2(\text{GNP})$	36 - electric machinery	20.8	This is a large, high-growth, dynamic, exporting industry that is sensitive to price.
6	$MWH = a+b_1\underset{\text{sales}}{(\text{lagged})}+B_2(\text{GNP})$	38 - instruments	16.9	This is a large, energy-intensive, capital-intensive industry affected by the national market.
7	$MWH = \dfrac{\text{SIC growth rate}}{\text{growth rate of other SIC codes}}(\text{lagged sales})$	25 - furniture 26 - pulp and paper 27 - printing 29 - petroleum	0.1 7.6 4.5 0.5	Historical ratios were used, because data problems made it difficult to find a workable set of variables that produced acceptable statistics.

Source: <u>Forecast</u>, at E.4 - E.11, E.14 - E.17, E.24 - E.25.

The Company made its choice of variables by analyzing the particular structure of each industrial subgroup's use of energy and its relationship to certain important explanatory variables, including those eventually selected: production for a national market; changes in the number of persons employed in the SIC subgroup within the Boston Edison territory; sensitivity to changes in the price of electricity, and the industry's previous year's electricity consumption. Boston Edison settled on an equation for each SIC group after balancing the logic of including different independent variables and the strength of the statistics associated with each model specification. In many instances, the Company has managed to strike a sensible balance: For example, the use of price and lagged sales makes sense for modeling the future demand of old, energy- and capital- intensive industries (such as those included in the method 1 group in Figure 7) whose usage level will depend upon the fixed stock of capital and future energy prices. Fast-growing industries which have a large export market and need for electricity (such as SIC groups 35, 36, and 38 in Figure 7) are suitably modeled by using Gross National Product and employment. In other equations, however, the theoretical basis for the model specification seems weak. Such is the case for SIC groups 22 and 32, which are forecast with lagged sales only, and for the four groups (SIC 25, 26, 27 and 29) which are forecast by applying the historical ratio of each subgroup's growth rates to other industries' growth rates.

Overall, the results of these equations are reasonable and the Company's method for choosing them is acceptable. The Company experimented with many more variables than the ones listed above and with many different combinations of explanatory variables for each SIC group. The focus of the Company's efforts was to utilize variables with valid local time-series data, to try to include price variables wherever appropriate, and to develop models with strong theoretical foundations at least for the larger and more dynamic SIC groups. The Company has generally succeeded in these objectives, as shown in the equations used for SIC groups 35, 36, and 38, which accounted for 52 percent of industrial sales in 1982 and are expected to make up 58 percent in 1992. Further, the Company wanted to insure that its forecasts fit with independent judgmental forecasts of industrial changes and growth in the region in the decade ahead. The Council concludes that, overall, the direction and size of the industrial forecast and the growth estimates for the major SIC subgroups seem reasonable and the Company's general approach to deriving them seems acceptable given the relatively small size and declining importance of industrial sales in the Boston Edison territory.

However, the Council offers three specific criticisms of the industrial forecast. First, the Council questions the use of the "lagged sales" variable for a long-run forecast for so many of the SIC subgroups. Lagged sales seems more appropriate for short-run estimates than for long-run forecasts, because it fails to capture the effects on industries' energy use of potential long-run changes in the structure of the industries or in the energy-intensity of their plants. The Council encourages the Company to avoid use of lagged sales for long-run forecasts except where there are compelling conceptual reasons to do so.

Second, the Company has modified the results of the SIC-specific equations to reflect the effects of long-run price elasticities. The modification took the form of a post-hoc aggregate adjustment to the total industrial sales forecast (derived from the equations shown in Figure 7):

> We have estimated that the long-run elasticity of demand for electricity is -1.20 and the short-run elasticity is -.35. We assume that the long-run effect of a price change has taken place in ten or twenty years after the short-run effect. In this forecast, the effect is assumed to occur evenly over the ten years for increases in price and for declines in price, it is assumed to occur over twenty years. Thus for each year (except for 1974), the quantity which the model produces (without the modifications) is multiplied by
>
> | | | | | |
> |---|---|---|---|---|
> | -.85/10 ... | x | D | x | Y .[31] |
> | [or -.85/20] | | [change in price] | | [number of years elasticity has had to take effect] |

The Council concurs that it is desirable to attempt to capture the effects of price changes on industrial sales. However, the method the Company uses to introduce price effects into the forecast seems questionable for several reasons. First, it risks to overstate the effects of price for some industrial groups whose SIC-specific forecast equation already included price as an independent variable. Also, this aggregate approach across the entire industrial customer mix makes it difficult for the final forecast to reflect differences among industrial subgroups' sensitivity to price changes. Finally, this post-hoc price adjustment makes it difficult to reconcile the demand growth rates of the individual SIC subgroups with the much lower growth rate for the industrial sector as a whole. This inconsistency makes it difficult to follow the documentation for the industrial forecast and problematic to justify the growth rates of the individual subgroups. The Council strongly encourages the Company to develop another, more disaggregated method for introducing long-run price elasticity into its industrial forecast.

Finally, the industrial forecast is the one sector that could stand to benefit from better data collection. The Company has made tremendous progress in its residential and commercial sectors in choosing variables and sources of data that capture energy-consuming behavior of the Company's own customers. The Company should attempt to obtain data on other variables important to industrial production levels, such as Gross State Product and value added, and their relationship to energy use. Additionally, the Company should try to integrate data from individual customers, including but not limited to large firms' judgments as to their long-run plans for expansion and energy use, into the Boston Edison industrial forecasting methodology.

31. Forecast, p. E-12.

F. Price and Peakload Forecasts

The Company has not introduced any major changes in the methods it uses to estimate electricity price and peakload growth, although both the price forecast and the peakload forecast include more recent data about the Company's actual load factors, the Company's plans to convert several power plants to coal, and its predictions about the future price of alternative fuels. The Company has provided slightly better documentation of these estimating methodologies and data sources than in the previous filing, and thus has responded to one of the Council's criticisms in the past decision (7 DOMSC 93 at 120).

Because of these few changes, the Council reiterates the concerns it raised in the past decision:

> First the Company should expand the documentation of the price forecast methodology. Current documentation is inadequate to the task of explaining a fairly complex and interesting methodology, describing the process of development and specification of the model, and presenting the model's data base....
>
> A complex forecasting problem such as projecting electricity price requires some assumptions to make the problem manageable. However, the Council would have more confidence in the price model if the Company did not assume that the relative shares of base revenue among customer classes would be constant over the forecast period...The Company should attempts to differentiate among customer classes in terms of share of revenue because actual rates vary by class and because growth rates in energy requirements are forecasted to differ by class....
>
> Fourth, the uncertainty in forecasting electricity price needs to be addressed explicitly... Sensitivity analysis would be especially useful to test the various effects related to forecasted fuel price levels: costs, in-service dates, and scheduling of new or converted generating units, and assumptions about conservation, load management, and renewable energy resources...[31]
>
> The weakness of the peak load forecast methodology is the assumption that class-specific peak factors will be constant over the forecast period. Although the Company argues that the assumption is reasonable...actual peak factors have varied by as much as 27.6%...since 1975.
>
> It is not clear whether the values of peak factors assumed by BECo follow some discernable trend, vary around some mean, or follow no predictable pattern. The significant differences in peak factors over a few years indicate a need for the Company to examine its load research data, identify determinants of change in peak

31. 7 DOMSC 93 at 119, 120, 123, 124.

> factors and identify actual trends, or likely means, in the values of peak factors. Although the overall approach to peak load forecasting is quite reasonable, the assumption of constant peak factors potentially lessen the reliability of the long-range load forecast.[32]

In its next filing, the Council expects Boston Edison to provide more complete documentation on its price forecasts. The documentation should also include, but not be limited to, forecasts of oil prices, coal prices, and nuclear fuel prices, as well as copies of annual production costing runs showing dispatching and availability assumptions.

Additionally, the peakload forecast, so critical to the Company's long-range supply plan, would benefit from an investigation into the appropriateness of utilizing an hourly demand load model. The model might be used, for example, to simulate how load-management measures might affect growth in peak demand or the shape of load curves in the various sectors.

G. Conclusion

The Council concludes that Boston Edison's newest changes to its long-range demand forecasting methodology and data sources greatly enhance the appropriateness of the Company's forecasting technique and the reliability of the forecast results. The Company's efforts to upgrade the documentation of its filing and the methodological and data components of its forecast indicate the Company's commitment not just to maintaining its forecasting capabilities but also to improving the quality of its forecasts. Some of the changes appear to have come in response to past Council concerns (especially with respect to use of non-territory-specific data); others, such as the Company's adoption of the commercial end-use energy demand model, seem to have been the result of internal efforts to enhance the forecast. All of the major changes in this current demand forecast -- the new territory-specific demographic forecast and migration equation, the new residential appliance saturations developed from local saturation data and income forecasts, the entirely new commerical end-use model and data base, and the new industrial equations that employ territory data -- represent enhancements to the Company's forecasting capability. It is clear that the Company is moving in the direction of making increased use of local sources of information and innovative, appropriate methodologies, especially for key variables and sectors.

The Council reiterates several concerns that it raised in the body of this review. First, some of the equations the Company uses to estimate dependent variables (such as migration in and out of the

32. 7 DOMSC 93 at 192.

territory, or KWH usage by several industrial SIC subgroups) lack conceptual strength. As the Council has stated in the past, it prefers to see a balance of theory and statistics as the basis for its model specifications, rather than a favoring of equations with strong statistics but weak conceptual foundation. The Council is, however, aware of the difficulties of meeting that objective in modeling certain phenomena for which appropriate times-series data are lacking. In Boston Edison's case, the Council is generally satisfied that the process the Company used to choose its models was acceptable, in that it attempted to locate local data sources, it tested the performance of many different variables and equations, it evaluated the results of competing model specifications against internal judgment and independent sources of qualitative information, and it tried to choose the equation(s) that most reasonably balanced theoretical strength, statistical validity, and judgment. The Council recognizes the Company's efforts and concludes that its overall process of model and data selection, refinement and adjustment is appropriate and produces relatively reliable results. However, the Council directs the Company to monitor the performance of its equations and to continue to search for the best available method for forecasting migration and industrial electricity usage.

Additionally, the Council is concerned over the accuracy of the Company's residential appliance usage estimates, given that they depend upon price elasticity adjustments to national EEI data of 1970 vintage or older. The Council orders the Company to investigate the continued appropriateness of using these data for the Boston Edison service territory in the 1980's and early 1990's.

The Council further encourages the Company to conduct more analyses to gauge the sensitivity of forecast results to changes in key assumptions or data inputs. This seems an important but missing element of an otherwise high-quality forecasting effort. Sensitivity analysis would provide the Company with the ability to construct a confidence interval around its forecast results and to estimate what would happen to its forecast if key independent variables (such as oil prices, or appliance/equipment usage levels, or gross national product) do not behave as expected. The Council suggests that the Company invest resources in performing and supplying the results of sensitivity analyses of key variables as a way to enhance its planning process.

Finally, the Council is concerned with the Company's decision to present a "natural increase forecast" in its present filing, rather than a forecast that fully integrates the effects on energy requirements and demand of Company-sponsored conservation and load-management programs. This inconsistency undermines the Company's stated commitments to reliable forecasting and to implementing appropriate conservation and load-management programs as part of its long-range supply planning strategy. The Council therefore orders the Company in its next filing to produce a status report on the first year of results of implementation of its IMPACT 2000 programs and to integrate and justify the Company's expected long-run KWH and KW savings from the programs into its demand forecasts.

The Boston Edison demand forecast and methodology is hereby approved subject to Conditions.

III. ANALYSIS OF THE SUPPLY PLAN

A. Introduction

Boston Edison produces electricity at its own generation facilities, and purchases and sells power from individual generation facilities under capacity contracts with other electric utilities. In addition, the Company provides power to the Reading Municipal Light Plant, and is the sole supplier of electricity to the Concord, Norwood, and Wellesley Municipal Light Plants. The Company also exchanges power with other New England electric utilities as part of the New England Power Pool ("NEPOOL"). Tables 6 and 7 identify the Company's existing generation units, capacity purchase contracts, and capacity sales contracts.

Boston Edison relies heavily on oil-fired electric generating capacity to meet demand. Table S-1 shows that 1301.7 MW (48 percent) of its 2703.25 MW of summer-rated generation capacity use oil as the only source of fuel, while an additional 732 MW (27 percent) can use either oil or gas. Two of the oil-fired plants, New Boston 1 and 2, are base-loaded facilities and designated "must run" by NEPOOL. Two more oil-fired plants, Mystic 4 and 5, are designated "cycling" plants by Boston Edison, but are considered "must run" by NEPOOL. With so much oil-fired capacity on line so much of the time, 67 percent of the electricity generated by Boston Edison during 1978-1982 was produced by oil-fired units.

Aside from its oil-fired plants, the Company has only one base-load facility - the Pilgrim 1 nuclear power plant. When Pilgrim 1 is unavailable because of refueling, maintenance, or forced outage, Boston Edison becomes even more dependent on oil, either from its own plants or from NEPOOL purchases.

Boston Edison is well aware of its reliance on oil, and is in the process of taking steps to diversify its fuel mix. In 1982, in response to the Order in DPU 906 (after cancellation of the Company's Pilgrim 2 nuclear power plant), the Company revealed its program of Initiatives to Manage Production and Consumption Trends to the Year 2000 ("IMPACT 2000"). The program includes proposals to convert the New Boston Units 1 and 2 and Mystic Units 4, 5 and 6 plants from oil to coal, as well as a wide variety of proposals to encourage energy conservation and to utilize renewable energy resources. Furthermore, the Company has modified the boilers at its Mystic 7 plant and its Medway jets to burn either natural gas or oil, and has contracted with Boston Gas and Bay State Gas for gas supplies on an interruptible basis. Thus, in 1982, 25.69 percent of the electricity produced at Mystic 7 was produced from natural gas.

In addition to its heavy reliance on oil, Boston Edison's Forecast shows a capacity shortfall starting as early as 1990. Table 8 identifies the Company's summer peak demand projections, NEPOOL reserve requirements (assuming 18 percent for summer-peaking), Reading contract demand commitments, and available generating capacity through the summer

TABLE 6
Boston Edison Company
Existing Generation Units

Type	Name	Fuel	Megawatts Winter	Megawatts Summer	BECo share
Base Load	Pilgrim I	Nuclear	670	670	100%
	New Boston 1	Oil	380	380	100%
	New Boston 2	Oil	380	380	100%
	SUBTOTAL		1430	1430	
Cycling	Mystic 7	Oil/gas	592.0	592.0	100%
	Mystic 6	Oil	143.8	143.8	100
	Mystic 5	Oil	137.9	135.0	100
	Mystic 4	Oil	136.3	136.3	100
	Yarmouth 4	Oil	36.47	34.45	5.8881%
	SUBTOTAL		1046.47	1041.55	
Peaking	Medway J1	Oil/gas	64.0	45.0	100%
	Medway J2	Oil/gas	64.0	51.0	100
	Medway J3	Oil/gas	64.0	43.6	100
	L Street J3	Oil	23.0	18.0	100
	Fram. J1	Oil	15.0	12.5	100
	Fram. J2	Oil	15.0	12.5	100
	Fram. J3	Oil	15.0	12.5	100
	Edgar J1	Oil	15.0	12.1	100
	Edgar J2	Oil	15.0	12.0	100
	Mystic J1	Oil	15.0	12.5	
	SUBTOTAL		305.0	231.7	
	TOTAL		2781.47	2703.25	

Source: Forecast, II. I.7, Table E-12.

TABLE 7
Boston Edison Company
Purchases and Sales of Capacity

Seller/ Buyer	Plant	Description	Capacity (MW)	Contract Expiration Date	Total Before Expiration
PURCHASES					
Braintree	Potter 2	Oil	20	11/83	473.6
Braintree	Potter 2	Oil	24-60[a]	11/84	458.6
Braintree	Potter 2	Oil	5	11/83 to 11/84	434.6
Maine Elec.	Coleson Cove	New Brunswick import	18	11/85	429.6
New Brunswick Electric Power	Pt. Lepreau	New Brunswick import	100	11/90	411.6
New England Power Co.	Bear Swamp	Pumped storage	100	11/90	311.6
Yankee Atomic	Mass. Yankee	Nuclear	14.3	7/91	211.6
Conn. Atomic	Conn. Yankee	Nuclear	55.3	1/98	197.3
Canal Elec.	Canal 1	Oil	142	10/2001	142.0
SALES					
Braintree	System	-	24-60[a]	11/84	331.4
Bangor Hydro	Mystic 7	Oil/gas	95	11/84	307.4
Fitchburg	Pilgrim 1 NB1, NB2 or M7	Nuclear, Oil/gas	40	11/86	212.4
Montaup Elec.	Pilgrim 1	Nuclear	73.7	12/2000	172.4
COM Elec.	Pilgrim 1	Nuclear	73.7	12/2000	98.7
Municipals[b]	Pilgrim 1	Nuclear	25.0	12/2000	25.0

Source: Forecast, II. III. I-4, Table G-24; 8 DOMSC 192, 227; 9 DOMSC 222, 271; Answers to Information Requests SI-25 and SI-48.

a Varies monthly by agreement.
b. Includes capacity sales to Boylston, Holyoke, Hudson, Littleton, Marblehead, Middleboro, North Attleboro, Peabody, Reading (5 MW), Shrewsbury, Templeton, Wakefield, Westfield, and West Boylston Municipal Light Plants. Does not include 20-30 MW "contract demand" sales to Reading, or the "total requirements" of Concord, Wellesley or Norwood.

TABLE 8
Boston Edison Load and Capacity Forecast

LOAD AND RESERVE REQUIREMENTS	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
BECo summer peak[a]	2184	2245	2315	2332	2364	2399	2432	2481	2496	2518
NEPOOL reserve at 18%	393	404	417	420	426	432	438	447	449	453
SUBTOTAL	2577	2649	2732	2752	2790	2831	2870	2928	2945	2971
Reading Contract Demand	25	25	25	30	20	20	23	23	23	0
TOTAL	2602	2674	2757	2782	2810	2851	2893	2951	2968	2971
CAPACITY										
Existing generation	2703.25	2703.25	2703.25	2703.25	2703.25	2703.25	2703.25	2703.25	2703.25	2703.25
Capacity purchases	493.6	458.6	429.6	411.6	411.6	411.6	411.6	411.6	197.3	197.3
(Capacity sales)	(331.4)	(331.4)	(212.4)	(212.4)	(172.4)	(172.4)	(172.4)	(172.4)	(172.4)	(172.4)
TOTAL	2845.45	2830.45	2920.45	2902.45	2942.45	2942.45	2942.45	2942.45	2728.15	2728.15
EXCESS (DEFICIT) OF CAPACITY OVER LOAD AND RESERVE REQUIREMENTS	243.45	156.45	163.45	120.45	132.45	91.45	49.45	(8.55)	(239.85)	(242.85)
% EXCESS (DEFICIT)	9.4	5.9	5.9	4.3	4.7	3.2	1.7	(0.3)	(8.1)	(8.2)

Source: *Forecast*, I.H.9, I.H.-11, II.I-14 to 16, II. III-1 to 4, Tables E-8, E-11 E-17 and E-24; Answer to Information Request SI-48.

a Includes the forecasted peak loads of the "total requirements customers": Concord, Norwood and Wellsley Municipal Light Boards.

of 1992. Boston Edison appears to forecast a small capacity deficit in 1990, with major deficits in 1991 and 1992 after expiration of the Pt. Lepreau and Bear Swamp capacity contracts. These deficits are based on the Company's forecast of 1.59% compound annual peak growth from 1983-93, and notice of non-renewal of the Reading contract by 1986 as required by that contract.

Again, the record shows that Boston Edison is well aware of its long-term potential for capacity shortfalls. The IMPACT 2000 report proposes several initiatives for peak reduction through demand management, and for new capacity purchases from sources that range from new local generation to Canadian imports. Several of these initiatives are described in great depth in the IMPACT 2000 report; others are too early in their development for their availability to be viewed with confidence.

The Council recognizes that the IMPACT 2000 proposals for coal conversion, conservation, load management and capacity purchases have been the subject of lengthy and detailed proceedings before other state and local government agencies, notably the Department of Public Utilities ("DPU"),[33] the Massachusetts Environmental Protection Agency, and the Department of Environmental Quality Engineering. The proposals continue to be the subject of considerable uncertainty.

Because of our statutory mandate to "provide for a necessary energy supply for the commonwealth with a minimum impact on the environment at the lowest possible cost" (M.G.L. Chapter 164, Section 69H), the Council has an obligation to monitor these matters as well. We note that capacity shortfalls of any size within the forecast period are unacceptable to the Council, and we expect Boston Edison to resolve as many of the related uncertainties as are practicable in its next filing. To this end, we discuss the status and inherent trade-offs of the coal conversion projects in Section B; review the role of the IMPACT 2000 conservation and load management ("CLM") programs for increasing diversity and eliminating capacity shortfalls in Section C; examine the Company's record on renewables, cogeneration and small power production in Section D; and summarize our conclusions, recommendations and Conditions in Section E.

B. Coal Conversion

In its IMPACT 2000 report, Boston Edison proposed to convert its base-loaded New Boston Units 1 and 2 and cycling Mystic Units 4, 5 and 6 from oil to low sulfur (1.5 percent) coal. The capital cost of the coal conversions was originally projected to be $866 million[34] for boiler conversion, coal-handling systems, electrostatic precipitators, stack construction, ash disposal, and related expenses. The Company originally projected that the conversions would reduce its costs by $985 million (1983 dollars) by the year 2000.[35] Construction was

33. MDPU 1350. The Executive Office of Energy Resources and the Attorney General were among the Intervenors in that case.
34. Specifically, $514 Million for the New Boston units and $352 Million for the Mystic units, not including incremental operating expenses. See Answer to Information Request SI-86.
35. Based on a February, 1983, forecast of oil and coal prices. The $985 million is net savings allowing for the total costs of conversion. See Answer to Information Request SI-90.

originally anticipated to begin in 1985 and to be completed by 1988.

The coal conversion projects have changed since they were originally proposed. In February, 1984, Boston Edison announced its intent to add fuel gas desulfurizers ("scrubbers") to its New Boston units. The decision was in part a response to public concern with sulfur emission levels as described by the Company's Draft Environmental Impact Report ("DEIR") to the Massachusetts Executive Office of Environmental Affairs in the summer of 1983. The Company continues to work on project engineering and design studies, on securing the necessary environmental approvals, and on the development of its financing plans. Presentation of the Final Environmental Impact Report for the New Boston units is anticipated by April 1, 1984.

The Company has not yet made a final decision on the status of the proposed coal conversion of its Mystic units. The Company is concentrating its attention and efforts on the New Boston coal conversion because it is "the most feasible", and is "keeping open the option of continuing the proposed Mystic Station conversions" (Letter from John R. Stevens, Vice President of Boston Edison, to Sharon M. Pollard, Secretary, Office of Energy Resources, January 24, 1984).

While the Council applauds the Company's efforts, we recognize that coal conversion projects of this magnitude necessarily involve difficult trade-offs between diversity, cost, and environmental impact. The high cost of scrubbers to reduce sulfur emissions,[36] and the impact of these additional costs on the Company's ability to finance the project, are two examples of these trade-offs. Moreover, many of the trade-offs are difficult to quantify. The Company's recent announcement that it will install scrubbers at New Boston is a major step toward resolution of these trade-offs. However, the Company's plans are apparently still evolving, and the Council has yet to see Final Environmental Impact Reports ("FEIR's") for either of the coal conversion projects.

The Council conditioned our approval of Boston Edison's last supply plan on the requirement that the Company keep us informed of the status of its coal conversion projects. Though the projects have advanced considerably since that time, they have not yet been finalized. The Council remains concerned with the Company's heavy reliance on oil, as well as the environmental impacts and costs of coal conversion. Thus, the Council ORDERS the Company to continue to keep us informed of the status of its coal conversion projects. In particular, the Company shall provide the Council with a copy of the FEIR when it is issued, along with a summary of major changes that have occurred since issuance of the DEIR; shall notify the Council in writing when the Secretary of Environmental Affairs acts on the FEIR, and shall provide the Council with a summary of the comments on the FEIR, as well as the FEIR acceptance certificate if and when it is issued; and shall inform the Council in writing of the Company's final decision on whether to proceed with either project, including updated cost estimates, an updated permit application schedule (similar to that in the DEIR, Volume 3, Section 3), and estimates of on-line dates. If the Company decides to begin the permitting process before it makes a final decision on whether to

36. The scrubbers may add as much as $300 per installed KW to the cost of coal conversion at New Boston. See Answer to Information Request SI-87.

proceed, it shall inform the Council of the application and issuance dates for each of the required permits listed in in the DEIR as they occur. This Condition is affixed hereto as Condition 3.

At this point, we wish to emphasize that if Boston Edison decides not to proceed with its coal conversion plans, we will still require the Company to pursue other methods for reducing its reliance on oil. To its credit, the Company has identified a number of possible alternatives,[37] but has understandably delayed firm action until the course of its coal conversion efforts is better established. Nevertheless, if the coal conversions do not proceed as planned, we expect the Company to report in detail in its next Council filing on its alternatives for diversifying its fuel mix.

C. Conservation and Load Management ("CLM") Programs

Boston Edison's IMPACT 2000 report proposed fourteen energy conservation programs, ten load management programs and a communications program as part of a strategy to improve the efficiency of customer energy use, to reduce reliance on oil, and to defer the need for new capacity additions. All of the programs were reviewed extensively during the Company's previous rate case at the DPU (DPU 1350).

The Council commends the Company's apparent commitment to implementing CLM programs. We believe that CLM can play an important role in producing a least-cost supply plan, especially in view of the Company's heavy reliance on oil-fired capacity and forecasted capacity shortfalls in the 1990's. Further, during the implementation phase, CLM programs will provide an opportunity for the Company to acquire territory-specific experience and data for evaluating the impact and cost-effectiveness of each program.

On the other hand, if Boston Edison is relying on CLM programs to defer capacity additions and displace oil, then it needs to develop the ability to forecast and measure the impacts of these programs with confidence. A complete monitoring and data-acquisition effort would provide sufficient information to distinguish incremental impacts of the programs from normal responses to price, income, or other exogenous factors; to identify the cost of each program in comparable units; to determine whether energy or power reductions attributable to the program are maintained over time; and to analyze how the results of the pilot programs can be applied to anticipate the results of territory-wide programs. Moreover, the methodology for forecasting CLM program impacts should be based on substantially accurate information and reasonable statistical projection methods (M.G.L. Chapter 164, Section 69J), should be reviewable, appropriate and reliable, and should be integrated with the Company's demand forecast in order to take advantage of common data and information sources (see Sections II.C. and II.G., supra).

37. Some of the alternatives mentioned by the Company include: power imports from Hydro Quebec or the proposed Pt. Lepreau Unit 2; power purchases from the yet-to-be completed Seabrook 1, Seabrook 2 or Millstone 3 nuclear power plants; coal-fired power from conversions at Coleson Cove or Schiller Station, or from a new coal-fired unit at Sears Island or elsewhere; construction of peak-shaving jets; and power from cogeneration or renewable energy sources. See Answers to Information Requests SI-36, SI-71, SI-78, SI-79 and SI-80.

The Council is concerned that Boston Edison may not be doing enough to acquire the information necessary to evaluate its CLM program in a comprehensive fashion. The Company has stated its intent to monitor kilowatt reductions via "magnetic tape metering", and to use control groups "as necessary to assess reductions over normal (uncontrolled) customer operation" (Answer to Information Request S1-55). It has presented preliminary estimates of energy and peak power reductions for individual programs. Still, it has not yet shown in detail on the record how it intends to monitor program results; to compare programs with each other, with conventional supply sources, and with an absolute standard (such as the no-losers' test or other comparable test); to extrapolate results from pilot programs to territory wide programs; or to integrate program data with forecast data.

We therefore CONDITION approval of this Forecast on the resolution of these issues. The Company is hereby ORDERED to present a comprehensive plan for monitoring and evaluating its CLM programs in its next filing with the Council. The Council staff is available to meet with the Company to discuss compliance with this Condition upon request. This CONDITION is addressed in Condition 2.

D. Cogeneration and Renewables

As part of our review of the Company's supply planning, the Council needs to consider how electrical energy from cogeneration projects and renewable energy resources can provide the Company with opportunities to diversify its fuel mix, reduce its oil consumption, and defer capacity additions. Several other Massachusetts utilities have previously announced major initiatives to encourage electricity production from these sources.[38]

Boston Edison is a participant in a waste-to-energy cogeneration facility that is being sponsored by the City of Boston. The proposed facility will produce electricity for the Boston Edison system and steam for the Boston Steam district heating system. The proposed output of the facility is 12.6 - 39.5 MW of generating capacity, and 120,000 - 230,000 Mwh of electrical energy per year, depending on the amount of steam production. Cost estimates for the facility, scheduled for completion by 1987, range from \$50 million to \$150 million.[39]

Boston Edison currently receives cogenerated electricity from eight different facilities owned by its customers. In addition, the Company is interconnected with three customer-owned wind-turbine generators (totalling 17.5 kW), and is involved with four small-scale hydropower facilities that are being developed by its customers (totalling 2239 kW). The Company has also made nominal investments in solar photovoltaic and wind turbine generator projects that are proceeding within its service territory.

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38. See NEESPLAN, the New England Electric System, 7 DOMSC 270, 306 (1982); Program for the 80's and 90's, Northeast Utilities, 8 DOMSC 50, 120 (1982). See also 7 DOMSC 93, 155 (1982), Note 21.
39. See Draft Environmental Impact Report of the City of Boston's Waste-to-Energy Project, released on December 15, 1983.

Though the Council commends the Company for its cooperative role in the Boston waste-to-energy project and in the customer-initiated projects that are occurring within its service territory, we are concerned that the Company is not taking a more active and aggressive role in pursuing cogeneration and renewable energy projects.

The record seems to indicate that Boston Edison's efforts in the area of cogeneration are limited to a formal review of customer views of cogeneration[40] and assignment of a single individual to handle cogeneration and small power production inquiries. Simply stated, this level of effort is unacceptably low for a utility of Boston Edison's size. In view of the potential capacity and diversity benefits of cogeneration, we would expect the Company to do more than be a passive receptor of customer initiatives and perceptions. Rather, we expect the Company to take strong steps to identify cogeneration potential among its customers; to provide financial incentives, technical assistance, and indisputable evidence of an attitude of encouragement in order to change customer initiatives and perceptions; to put encouragement of cogeneration on a par with other aspects of the Company's services to its industrial and large commercial customers; and to dedicate corporate resources to these tasks commensurate with their diversity and capacity deferral benefits. We further suggest that the Company reconsider instituting contractual policies that include minimum floor-pricing opportunities for small power producers under appropriate circumstances. We hope and expect the Company to show us evidence of significant progress toward these ends by the time of its next filing.

E. Conclusion

The Council remains concerned about Boston Edison's heavy reliance on oil and possible capacity shortfalls in the 1990's. We are pleased that the Company has made a major commitment to fuel diversification through coal conversion, conservation, and load management in its IMPACT 2000 program, and we acknowledge that the Company is taking significant steps to address our concerns with diversity and long-term capacity shortfalls. The Company's coal conversion plans demand careful consideration of the trade-offs between diversity, cost and environmental impact, and we encourage the Company to achieve a speedy resolution of these issues in the best interest of its customers and the public at large. We remain concerned, though, that the Company is not doing enough to encourage cogeneration within its service territory.

40. This is part of the "R and D Pilot Program for Cogeneration," which is the follow-up to a survey entitled "Management Decisions for Cogeneration," prepared by the MIT Energy Lab in July, 1982. See Answer to Information Request SI-60. The MIT Energy Lab report, which identified factors that affect customer cogeneration decisions, has been criticized for lacking explanations for its assumptions, for the low response rate of the sampled customers, and for categorical exclusion of certain types of facilities. Answer to Information Request SI-36, Initital Brief of the Executive Office of Energy Resources, at 37. We find these criticisms compelling, and we are therefore inclined to put little confidence in the study's estimate of 106 MW of cogeneration potential within the Company's service territory.

The Company has been ORDERED to comply with supply Conditions regarding the status of its coal conversion projects and its plans for monitoring and evaluating its conservation and load management programs. These Conditions are affixed hereto as Conditions 2 and 3.

IV. DECISION AND ORDER

The Council hereby APPROVES conditionally the first Supplemnt to the Second Long-Range Forecast (1983-1992) of Electric Power Needs and Requirements of the Boston Edison Company (including the requirements of the Concord Municipal Light Plant, the Norwood Municipal Light Department, and the Electric Division of the Wellesley Board of Public Works). In its next supplement, due on February 1, 1985. The Council hereby ORDERS:

1. That the Company investigate the continued appropriateness of using the 1971 (and older) EEI data as the basis for forecasting post-1983 appliance usage estimates.

2. That the Company produce a status report on the first year of results of implementation of its IMPACT 2000 programs and integrate and justify the Company's expected long-run KWh and KW savings from the programs into its demand forecasts. The Company shall present a comprehensive plan for monitoring and evaluating these programs.

3. That the Company continue to keep the Council informed of the status of its coal conversion projects and provide the Council with information and materials as itemized on pp. 44-45 herein.

Lawrence W. Plitch, Esq.
Hearings Officer

On the Decision:

Susan Fallows Tierney
George Aronson

Unanimously APPROVED by the Energy Facilities Siting Council on March 5, 1984 by those members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs); Walter Headley (for James S. Hoyte, Secretary of Environmental Affairs); Joellen D'Esti (for Evelyn F. Murphy, Secretary of Economic Affairs); Robert W. Gillette (Public Environmental Member); Thomas J. Crowley (Public Member Engineering).

13 March 1984
Date

Sharon M. Pollard
Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of Taunton Municipal Lighting Plant's 1983 Long-Range Forecast of Electricity Needs and Resources	)	EFSC No. 83-51

FINAL DECISION

Lawrence W. Plitch, Esq.
Hearings Officer

William Febiger
Staff Analyst
On the Decision

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I. HISTORY OF THE PROCEEDINGS

The Taunton Municipal Lighting Plant (hereinafter "TMLP" or "Taunton") is an "electric company" as defined under the regulations of the Massachusetts Energy Facilities Siting Council (hereinafter "the Council" or "the EFSC"). EFSC Rule 3.3, 980 CMR 2.03. Pursuant to the provisions of M.G.L. c.164, sec. 69I, Taunton filed its 1983 Long Range Forecast with the Council on April 29, 1983. On May 10, 1983, Taunton was ordered to post Notice of Adjudicatory Proceeding. EFSC Rule 13.2, 980 CMR 1.03(2).

On June 6, 1983, Citizens for Limited Electric Rates, a Taunton area group of electric ratepayers, filed a Petition for Intervention with the Council. The Hearings Officer scheduled a pre-hearing conference for June 29, 1983. At that time, the Hearings Officer entertained a Motion on the part of Taunton to deny the petition to intervene. In addition, an outline of the principal issues in the case was discussed and a tentative procedural schedule was set. Following consideration of an amended petition to intervene and a further motion in opposition filed by Taunton, four named individuals (Messrs. Murphy, Rocha, Veradt and Garda) collectively known as "Citizens For Limited Electric Rates", were allowed into the proceeding as interested persons. <u>See</u>, <u>Procedural Order</u>, July 25, 1983.

Two sets of information requests were issued to Taunton and two technical sessions were held wherein the Company provided further explanation regarding the issues involved in its 1983 Long-Range Forecast. A briefing date of December 30, 1983, was set for the parties in the proceeding. The interested persons opted not to exercise their right to file a brief at that time.

II. INTRODUCTION

Under EFSC Rules 63 and 69, the Council is required to apply several criteria to its review of electric utility forecasts. The Taunton Municipal Lighting Plant, as with all the electric utilities under the Council's jurisdiction, must submit a <u>reviewable</u> forecast, which is an <u>appropriate</u> filing for its particular system and which is <u>reliable</u> in its ability to forecast electric demand.

Taunton must also present an accurate supply plan necessary to meet the forecasted demand of its customers. TMLP has stated that the EFSC "does not have jurisdiction to decide on an electric company's supply plan." <u>Brief TMLP</u> at 82. (December 30, 1983). In fact, the EFSC has authority to rule on the supply plans of jurisdictional electric companies under M.C.L. c. 164, Sec. 69I and J. It has further regulatory authority to do so under EFSC Rule 64. The Council has ruled on a utility's supply plan in each and every electric company forecast it has reviewed. This includes Taunton's last Forecast filing. <u>See</u>, 3 <u>DOMSC</u> 152, April 7, 1980. Therefore, the Council will review and consider for approval Taunton's 1983 Supply Plan, <u>See also</u>, <u>Procedural Order</u>, EFSC No. 82-1 (August 3, 1983).

III. COMPLIANCE WITH CONDITIONS IN EFSC 79-51

The conditional approval of TMLP's last Forecast in 1980 specified that six conditions be met. Of four demand conditions, three concerned possible continued use of trend line analysis for future forecasts. TMLP later submitted, as part of TMLP's Occasional Supplement under EFSC 79-51A, a "compliance plan" that included provisions for testing of econometric models in its future demand forecast filings. 8 DOMSC 15 (1982); Exhibit 19. A fourth demand condition concerned compliance with Rule 63.5, Methodology for Forecasting Demand. The two supply conditions in EFSC 79-51 concerned customer conservation and pursuit of alternatives to oil-fired generation.

A. Reviewability, Appropriateness and Reliability

Previous Conditions 1, 2 and 4 required that any trend line analysis be reviewable and appropriate, that judgemental modification be explained, that causal factors be identified, and that the suitability of the Forecast be addressed. Trend line analysis was used to forecast sales for only one class in EFSC 83-51 -- the domestic hot water class. TMLP used trend line analysis for this class only after unsuccessful attempts to develop statistically supportable economtric models. The trend line analysis was based on a statistical method, and was thus reviewable. TMLP cited the basically flat nature of base period trends as an obstacle to obtaining high explanatory coefficients. 1983 Forecast, p. III-19. TMLP explained its judgements, and generally used a reasonable approach under the circumstances.

TMLP's efforts not withstanding, the forecast did not identify causes for the flat-to-gradually declining sales in the domestic hot water class. TMLP failed to explicitly relate sales trends to electricity prices or conservation and load management in its service area. TMLP's ongoing and future efforts in conservation and load management, including appliance surveys, could usefully be related to future forecasts for the hot water class. See infra, Sec. IV-C, V-H.

TMLP has gone beyond the requirements of EFSC 79-51 in developing econometric models for four other customer classes and in considering end use modeling. TMLP's efforts are in accordance with commitments made in its 1982 compliance plan to test econometric models and consider end use modeling. In this Decision, TMLP's progress with econometric modeling has been reviewed in detail, and has been strongly commended. See infra, Sec. IV.

Although stated in terms of trend line analysis, previous Conditions 1, 2 and 4 reflected general requirements that would apply to any forecast model. Accordingly, the conformance of TMLP's econometric models to these conditions has been considered. The models are found to be reviewable, the reasons for their selection having been satisfactorily explained and the independent variables, which represent causal factors, having been identified. However, areas for improvement are identified relating to the suitability of the models in their reflection of causal factors. Principal concerns involve the reliance on a single predominant driving variable to explain increases in sales. In three residential and commercial class models based on service area population, use of linear regression resulted in forecast models that incorporate high negative intercepts, together with high offsetting positive coefficients for the driving variable population. These results suggest a need for using a non-linear model and possibly introducing additional independent variables. For the industrial class, TMLP did not disaggregate industrial sales data by 2-digit SIC code, as required by EFSC Rule 63.7. The lack of attention to sectoral trends detracts from the general reliability of the industrial forecast. See Infra, Sec. IV-E.

B. Compliance with EFSC Rule 63.5

Condition 3 addressed methodological concerns under EFSC Rule 63.5, particularly those relating to documentation and explanation of the determinants of future demand as used in demand forecasts. The Council's concerns with this issue have been satisfied in the current proceeding, and TMLP has thus met this condition.

C. Customer Conservation

Condition 5 required the quantification of customer conservation over the forecast period including the reflection of state and federal conservation programs. Although TMLP has reported activities under the Residential Conservation Program in its area -- Bay State Gas Company's "Project H.E.A.T." -- conservation was not quantified. As a response to this condition, TMLP has implemented a program, "Energy Services Planning", to address conservation among other concerns. See infra, Sec. V-H.

D. Alternatives to Oil-Fired Generation

Condition 6 required pursuit of all supply options including conservation, load management and industrial cogeneration. Pursuit of a municipal refuse burning option, and a report on shared co-generation at Myles Standish Industrial Park were specifically required. TMLP has generally met this condition, including a study of load management potential, studies involving coal and refuse burning and cogeneration, and analyses of power purchase and capacity options involving natural gas renewables, and nuclear sources of energy. See infra, sec. V-D through V-H. In addition, TMLP has established a goal for reduced oil dependence and an integrated management approach to achieve this goal. See infra, Sec. V-B, V-C.

IV. DEMAND FORECAST

A. Overview of Forecast Methodology

In EFSC 83-51, econometric models have been developed for four established customer classes, replacing the trend line analyses of former forecasts. Additional forecasts of number of customers and average use per customer have been developed to help verify the demand forecasts for individual classes. TMLP has been diligent in explaining the judgements it made to select model runs as part of its Forecast.

Each of the four econometric models incorporates linear regression with two independent variables. Service area population represents the principal driving variable in models for the residential base rate, residential heating, and commercial classes; gross national product (GNP) is the driving variable for industrial sales. Price of electricity, deflated or actual, is included with a negative coefficient in models for the residential, commercial and industrial classes; degree days with a positive coefficient is the second independent variable for residential heating.

In EFSC 83-51, TMLP has for the first time included a separate forecast for the residential electric hot water customer class. Time trending was used to project the number of customers and average use per customer in this class. Regression analyses were attempted for this class, but did not provide a reliable basis for forecasting sales.

In 1980/1981, TMLP established a separate rate for master metered apartments with electric heat. As there are as yet insufficient base year data to allow separate forecasting, these customers are included in the overall electric heat class.

B. Overall System Requirements

TMLP has forecast total electrical energy requirements for its system to grow from 323,780 megawatthours (Mwh) in 1981 to 391,800 Mwh in 1992; a 1.75% equivalent annual compound growth rate. For the same eleven year period, the winter peak is forecast to grow at a 1.29% annual compound rate from 65.0 megawatts (Mw) to 74.9 Mw. These system growth rates are substantially lower than the corresponding 1978-89 growth rates in TMLP's previous Forecast 79-51 (5.3% for total energy and 5.0% for winter peak).

Table 1 shows shares of system sales and compares base period and forecast period growth rates for the respective classes. The forecasted growth rate in total energy is about two thirds the 1970-1981 base period growth rate of 2.64%. The commercial and residential electric

TABLE 1
Relative Sizes and Growth Rates of Customer Class

	Compound Average Annual Per Cent Change		Per Cent of System Sales	
Class	1970-81	1981-92	1981	1992
Residential:				
Base Rate	3.56	2.12	22.6	23.5
Electric Heat	10.74	1.37	5.8	5.5
Domestic Hot Water	-0.08	-0.26	10.6	8.5
Commercial	7.6	1.6	18.5	18.2
Industrial	1.17	2.32	40.7	43.2
Street Lighting	2.8	-3.0	1.8	1.1
Total Sales	2.82	1.77	100	100
Total Requirements*	2.64	1.75	-	-

* Includes internal use and losses.
Based in part on staff calculations. 1983 Forecast p. IV-2, IV-3.

heat classes, forecast to grow at 1.6% and 1.37% respectively, can be seen as leading the forecasted slow-down in overall system growth. Conversely, the industrial class, forecast to grow at 2.32%, shows an increase from its base period growth rate.

C. Residential Forecast

Residential sales are forecast for three classes -- base rate, electric heat and electric hot water. Together, they account for 37.5% of total 1992 system sales. In 1981, there were 14,610 base rate customers, 1,085 electric heat customers, and 3,892 hot water customers.

Sales for the base rate class are forecast to increase at an annual compound rate of 2.12%, second only to the industrial class. Sales for the electric heat class are forecast to grow at 1.37% annually, while those for the hot water class are forecast to decrease to 97% of their 1981 level by 1992.

TMLP made trend line analyses to help verify its econometric forecasts. Combined trending of average use per customer and the number of customers divided by system area population yields growth rates of 2.54% and 1.28% for the base rate and electric heat classes, respectively. These projections are reasonably consistent with the econometric forecasts.

As a cross-check on its statistical models, TMLP also identified known residential projects and their prospective electrical requirements. Eleven projects are expected to add 1,351 Mwh in annual load over the next three years, accounting for a little under one year's growth as forecast by the residential models. Looking ahead five to ten years, TMLP has cited an additional 3,748 Mwh of annual load expected from three large mobile home parks, representing another three years' worth of forecast growth. The project-specific information serves essentially as a check on the population projections of the Southeast Regional Planning and Economic Development District (SERPED), which TMLP has incorporated as the driving variable in its residential models.

TMLP has done a commendable job in developing population-based statistical methods for its residential classes. In addition to population, TMLP has successfully incorporated price of electricity in its base rate class forecast and degree days in its electric heat class forecast. TMLP has also made considerable efforts, although with little success so far, to include income variables in its residential models.

Trend line analysis was used to forecast sales for the domestic hot water class. TMLP used trend line analysis only after unsuccessful attempts to develop statistically supportable econometric models. The trend line analysis was based on a documented statistical method, and was thus reviewable. TMLP cited the basically flat nature of base period trends as an obstacle to obtaining high explanatory coefficients. TMLP explained its judgements, and generally used a reasonable approach under the circumstances. TMLP's efforts not withstanding, the Forecast did not identify causes for the gradual decline in sales. TMLP failed to explicitly relate sales trends to electricity prices or conservation in its service area. TMLP's ongoing and future efforts in conservation and load management, including appliance surveys, could usefully be related to future forecasts for the hot water class. As a CONDITION for approval of its 1983 Forecast, TMLP shall in future filings demonstrate its further efforts and/or plans to explicitly reflect prices of electricity and conservation/load management trends in its forecasts for the domestic hot water class.

In its review of TMLP's econometric models, the Council considered the sensitivity of sales forecasts to variation in the independent variables. Using the 1992 forecast values as points of reference, the elasticity of demand to population is 2.7 and 2.2 for the base rate and electric heat classes, respectively. The elasticity of demand to price of electricity is 0.1 for the base rate class; degree days, a random variable held constant for forecasting purposes, was not analyzed. Both econometric models thus appear to be relatively dependent on population projections.

The sensitivities to population, as reflected in the elasticities of 2-3 times unity, are noteworthy in their own right. This is not to say that they detract from the high explanatory coefficients that TMLP has derived in its forecast, or the adequacy of TMLP's model as a statistical method. Nor do they detract from the successful incorporation of price of electricity as a negative explanatory factor. However, the forecast provides little insight into the factors that affect sales positively such as household and income trends. Questions may be raised as to why or how, in the event that the CPI adjusted price of electricity remains flat, sales would grow essentially in direct response to population increases -- and generally at more than twice the rate.

The reliability of TMLP's econometric forecasts for residential sales could be improved with greater attention to factors that influence the relationship between the independent variables and sales. The recent slow-down in electricity price increases,[1] whether temporary or otherwise, heightens the importance of considering other factors, and of better understanding the elasticities noted above. Some areas in which improvements could be tried are discussed below.

One concern is that only linear models have been tried by TMLP. Logarithmic or other formats may better explain past and expected relationships between the independent variable and sales. Alternative formats also may allow additional independent variables to be successfully introduced into the model, and the sensitivity to any one variable thereby reduced.

TMLP has cited limited computer capability and previous concurrence by the Council as reasons for the limitation to linear regression in EFSC 83-51. Information Return D-2. However, TMLP has now expanded its computer forecasting capabilities. Information Return DD-2. As a

1. The monthly bills from December, 1982 to November, 1983 to a TMLP commercial customer using a hypothetical 10,000 Kwh of a maximum rate of 40Kw have been 2% higher on average than the bills 12 months earlier. Energy Users News, V.8, Nos. 2,7,11,15,19,24,28, 32,37,41,46,50.

CONDITION for approval of its 1983 Forecast Filing, TMLP is required to test other formats beyond linear regression in its econometric models for presentation in its future filings.

Another concern is that TMLP has not explicitly incorporated basic customer characteristics, such as household size, income, or type of unit. As noted above, TMLP did reflect population-customer relationships in its trend line verification analyses. However, census data show that a significant downward trend in household size developed in the 1970's; the trend may or may not be continuing in the 1980's. Other changes may also be occurring in the service area; increased mobile home development is an example. 1983 Forecast, p. IV-29.

TMLP has cited the unreliability of SERPED's household projections as the reason for avoiding household-based forecasting. Information Return, D-5. Yet, TMLP believes SERPED's population projections are reliable, which suggests that there may be difficulties with SERPED's assumptions concerning average household size. It may be useful for TMLP to consult with other local or state agencies that use housing data to try to resolve this issue. As a CONDITION for approval of its 1983 Forecast, TMLP shall for its next filing test model runs incorporating residential customer characteristics such as personal income and household type and size.

A final issue is that, in choosing an econometric approach, TMLP has not reflected appliance-specific data or trends in its residential models. TMLP has cited unreliable data, and the high costs and time requirements for supplemental appliance-use surveys, as reasons for not incorporating end use modeling approaches.

TMLP has reviewed the experiences of other utilities that have conducted appliance-use surveys. A large share of the costs of a comprehensive survey is, in TMLP's view, independent of system size. Such costs are estimated by TMLP to include $50,000 for developing a survey and $25,000 for validating the results. With the hiring of in-house expertise to interpret and biannually update surveys, TMLP concludes that overall long term costs of $100,000 per year, or about $5 per TMLP customer, could be expected. Information Return DD-8.

The Council concurs that the cost per customer of a comprehensive survey could be substantially more for TMLP than for the larger systems that have conducted them in Massachusetts and elsewhere. At this time, the Council can support TMLP's continued use of econometric models for its basic forecasting purposes. Nevertheless, the needs of an agressive conservation/load management program most likely will merit selective or limited surveys of appliance use in TMLP's service territory. See infra, Sec. V-H. TMLP also should continue to actively monitor work by other utilities and NEPOOL, and reevaluate the relative costs and benefits of an overall end use modeling approach as circumstances warrant.

D. Commercial Forecast

The forecast annual compound rate of growth in commercial sales is 1.6%. Sales grew at 13.7% annually between 1970 and 1976, resulting in the second sharpest 1970-1981 increase of all the classes. However, sales became nearly flat during the latter half of the base period between 1976 and 1981.

The commercial model incorporates projections of service area population and actual price of electricity as independent variables. For the residential (base rate) and industrial models, TMLP has argued that sales are more related to relative (CPI adjusted) price than actual price of electricity. 1983 Forecast, p.III-10, 17. However, actual price has been used for the commercial class, as it is the variable that appears to be best able to statistically explain the dramatic reduction in sales growth during the mid-seventies.

As a cross-check on the econometric model, TMLP also identified known planned commercial projects and their prospective electrical requirements. Fourteen projects are expected to add 3,118 Mwh in annual load over the next three years. The additional requirements would account for nearly three years' worth of sales growth as forecast by the econometric model.

The Council has considered the sensitivity of the model to changes in the independent variables. Using 1992 forecast values as points of reference, the elasticity of sales to population is 7.1, and the elasticity of sales to price is 0.7. These elasticity values are the highest of any class for the respective variables. They appear to reflect the unusual pattern of commercial sales growth during the base period, and the role of price changes in statistically explaining that pattern.

TMLP's commercial forecast is reasonable and based on an acceptable statistical method. TMLP's judgements in selecting the model are explained and appear sound, given the model runs attempted.

However, the basis for the high rate of sales growth in the early baseyears, and the resulting high elasticity in the model to the driving variable population, does not appear to have been investigated. In addition, TMLP does not explain why commercial sales are most affected by actual price changes when industrial and residential sales are most affected by relative price changes. In light of the recent slow-down in electricity price increases[2], it is evident that other factors that might help explain the relationship between population and sales could usefully be considered.

Two additional important factors that could conceivably explain the eratic pattern of commercial sales growth are (1) changes in travel patterns in to or out of the service area for shopping purposes and (2)

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2. See supra, Footnote 1.

relocation or expansion of internally supported retail activities into more modern and spacious facilities. TMLP essentially dismisses the first factor by pointing out that commercial activity in the service area is of a "necessity and closed-area nature". 1983 Forecast, p. III-3. Alternative explanations for the past growth in commercial sales have not been provided.

It is clear that retail expansion did occcur in the past, and can be expected in the future based on the known commercial projects cited in the Forecast. However, the reliability of the forecast could be improved by a fuller understanding of the high rate of growth in the early base years, and an assessment of the prospects for similar rates of commercial growth in the future should electricity price increases be less than projected.

Passage of time may allow TMLP to use a more representative base period to update its commercial forecast in future filings. As a CONDITION for approval of its 1983 Forecast, TMLP shall in its next filing test other formats besides linear regression in its econometric model for commercial sales.

E. Industrial Forecast

The industrial class is the largest class; its share of system sales is forecast to increase from 41% in 1981 to 43% in 1992. The forecast annual compound growth rate for the class is 2.32%, highest of all the classes forecast.

The forecast growth in industrial sales reflects, with apparent moderation, the even higher growth rate of 2.97% in the driving independent variable -- deflated GNP. In addition, the selected model, which is based on the 1975-1981 post-embargo base period, was chosen over two similar runs based on a longer 1970-1981 base period that yielded even higher growth rates. The two 1970-1981 runs, one with and one without a dummy variable, produced statistically acceptable results with growth rates of 2.6% and 3.75% respectively.

While basing its industrial forecast on national variables, TMLP has noted planned local industrial developments that help support expectations of growth in the service area. Nine industrial projects are expected to be completed within two years, with an additional electrical service capacity of 5500 Kw. The prospective annual electrical requirements of these new customers exceed 10,000 Mwh. Information Returns DD-6, DD-7. By way of verification, this accounts for approximately four years' worth of systemwide industrial growth as forecast by TMLP's econometric model.

Based on available data, sizable losses in industrial activity since the last Forecast must also be acknowledged. Two large metal industries and a chemical firm, together requiring over 16,000 Mwh in 1978/1979, have each declined by more than 50% as of 1982/1983. Largely balancing these losses, 3 manufacturing customers showed gains of 2,000 Mwh or more each over the same period. Information Return DD-4.

However, one of these customers, a major tenant at the Myles Standish Industrial Park requiring 3,500 Mwh in 1982/83, has since announced plans to relocate outside the United States. Information Return D-8.

On balance, there does appear to be significant evidence of local industrial growth that supports TMLP's forecast for industrial sales. However, the losses noted above are a concern, particularly in light of the importance of metals industries in the Taunton area. Clear conclusions about the prospects for cyclical recovery in these industries cannot be drawn in this review.

Notwithstanding TMLP's efforts at forecast verification, the reliance of the statistical model on overall GNP represents a limitation in the reliability of the Forecast. The model incorporates variables that can reflect neither relative regional trends for the service area nor relative sectoral trends for the types of industries that are predominant in the service area.

With regard to sectoral trends, TMLP has not made a commitment to begin classifying industrial sales data by Standard Industrial Classification (SIC) code. TMLP believes that the differentiation of industries as to energy use (relative to GNP) is not really that significant at the two-digit level, and thus questions the benefits of classification. Information Return DD-3. Methodological difficulties in allocating TMLP industries to particular sectors and obtaining industrial output projections by sector are also cited. Infomration Return DD-2.

Analyses by other utilities, however, do show important differences in the growth expectations of individual sectors. For example, in a recent forecast, Commonwealth Electric Company incorporated 1981-91 projections of employment change by sector that varied from -1.98% to +2.92%. 9 DOMSC 301. In the TMLP system, it has been noted that declines in electrical requirements of over 50% between 1978/79 and 1982/83 were experienced by three of TMLP's largest customers. See Supra. TMLP has not provided evidence that the electrical requirements of these firms, or the sectors of which they are a part, can reasonably be expected to return to former levels.

Sectoral analyses could give TMLP the capability to reflect not only differing expectations for growth in respective industries, but also industry-specific trends in technological change affecting electricity use. The Council believes that insight into the factors affecting demand is a major benefit of forecast development. Such insight may in fact contribute to the development and implementation of conservation and load management approaches.

In light of the above factors, and the large share of system sales and sales growth represented by industry, disaggregation is warranted. EFSC Rule 63.7 requires disaggregation of the industrial forecast at the 2-digit SIC code level. It is recognized that development of the data base needed for disaggregated forecast modeling may require several years. It may also be appropriate to initially focus on selected large sectors in developing and analyzing disaggregated sales data. As a CONDITION for approval of its 1983 Forecast, TMLP shall make a significant start toward disaggregating its current and future industrial sales data by 2-digit SIC code, and report its progress in the next and future filings.

V. SUPPLY FORECAST

A. Background

The TMLP owns substantial intermediate and peaking capacity -- including the 110 MW Cleary-Flood No. 9 combined cycle unit and the 25 MW Cleary-Flood No. 8 conventional oil unit. TMLP has also acquired unit purchase contracts for additional capacity to provide both base load capability and unit diversity. The unit purchases currently include life-of-unit contracts for 6.9 MW of nuclear capacity and contracts due to expire in late 1984 for 20.27 MW of base load oil capacity.

The disposition of Cleary No. 9 is a major consideration in TMLP's supply planning. Since the unit began operation in 1976, TMLP has had an agreement with Montaup Electric Company to share the 110 MW capability entitlement. Taunton's share is determined based on the portion of its annual NEPOOL responsibility which remains unmet by other specified entitlements; Montaup purchases the remainder. Thus, TMLP has had a built-in mechanism for matching year-to-year increases in its requirements not covered by other specified entitlements.

The Taunton-Montaup agreement is due to expire when Montaup's cumulative purchases reach 25% of Cleary's expected life-of-unit capacity. In the current forecast, the expiration date is projected to occur by Winter 1985-86. 1983 Forecast, p. V-11. In the absence of a new sales agreement, TMLP's share of Cleary 9 would increase at that time from 45% to 100%, or by 62.5 MW. A 100% entitlement in Cleary 9 would result in annual system capacities for TMLP that are approximately twice its system requirements over the remainder of the forecast period.

Another major feature of TMLP's supply planning since EFSC 79-51 has been the substantial reduction of proposed nuclear capacity. Planned nuclear capacity in the current forecast includes only 2.3 MW of Seabrook I and II. However, the previous supply plan as finally approved in 1980 provided not only the 2.3 MW share of Seabrook, but also a 6.9 MW share of Pilgrim II, a 11.5 share of Millstone III through Massachusetts Municipal Wholesale Electric Company (MMWEC), and an additional 3 MW share of Seabrook I and II. Since then, Pilgrim II and the MMWEC Millstone purchase have been cancelled, and TMLP has dropped its plans to purchase more Seabrook capacity.

The proposed nuclear purchases were intended to reduce fuel costs by displacing oil, to provide unit and fuel diversity, and to reduce oil dependence in accordance with state and national policy. When combined with the 6.9 MW of existing ownership in Vermont and Maine Yankee nuclear units, TMLP's nuclear capacity as proposed in EFSC 79-51 was expected to reach 30.6 MW. 3 DOMSC 127, 143-144 (February 29, 1980). This is 47% of the Winter peak experienced in 1981, and 41% of the peak now being forecast for 1992. By comparison, the nuclear capacity in the current filing amounts to 9.2 MW, which is 14% of the 1981 peak and 12% of the forecast 1992 peak.

B. Goal For Reduced Oil Dependence

In the current forecast, TMLP has set a goal for reduced oil dependence -- 25% or less of total energy by 1990. It is estimated by TMLP that approximately 30 MW of new non-oil fired base load capacity will be required to meet that goal. Information Return SS-2. The 30 MW of new capacity would be combined with the 9.2 MW of existing and approved nuclear capacity[3], and a partial-year pro-rated portion of the 23 MW capacity Cleary 9 combustion turbine unit that was recently converted to burn natural gas as well as oil (See infra, Sec. D-2) -- the resultant total would be over 50 MW of non-oil capacity.

The TMLP believes it has significant flexibility in its current supply planning program and is thus well positioned to approach its 30 MW goal. The system enjoys long-term excess capacity, and TMLP suggests its 110 MW Cleary 9 unit can be effectively marketed over the forecast period to other systems potentially beset with deficiencies. The Council believes that the flexibility to burn natural gas and/or coal might enhance TMLP's ability to market Cleary 9's capacity. See infra, Sec. D-2, F-4. TMLP also cites flexibility for committing new capital, as its current commitments for generating facilities are limited to annual debt service requirements for Cleary 9 (just over $2 million)[4] plus TMLP's small share (2.3MW) of Seabrook I and II.[5]

TMLP has made important initiatives to both develop new non-oil supply options and improve the efficiency, and thus the attractiveness to other utilities, of Cleary 9. These initiatives and their costs are discussed in more detail in later sections. The Council believes that TMLP's goal for oil displacement is commendable, and is consistent with conditions and expectations relating to system diversity raised in previous proceedings. See supra, Sec. III-D, V-A.

C. Program for Integrated Supply Planning

In the course of the current proceeding, TMLP has proposed and begun instituting a new supply planning program concept termed "Energy Services Planning." The program, including both TMLP projects and technical assistance to TMLP customers, is intended to bring about "diversified strategies to incorporate the efficient use of energy resources." Information Return S-11. TMLP's future efforts to implement load management, cogeneration and renewables within its

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3. By action of the joint owners of the Seabrook project on September 8, 1983, completion of Seabrook II has been delayed to allow completion of Seabrook I. Thus, TMLP's 1.15 MW share of Seabrook II may not be available in 1990, reducing TMLP's existing and approved nuclear capacity to 8.05 MW.
4. See Return of the City of Taunton to the DPU, 1982.
5. See infra, Sec. E, for a discussion of costs.

service area will fall primarily under the new program. New system concepts, for example thermal distribution circuits, will be considered where feasible.

The TMLP is acquiring new planning models and staff expertise to analyze options and technologies from both an energy capability and an economic/financial perspective. In addition, an overall strategic model will be used to help integrate traditional supply options and energy services planning concepts. Information Return SS-1.

A comprehensive planning program such as the one being instituted is an excellent approach, and the Council strongly supports TMLP's efforts.

D. Reliability and Efficiency of Cleary 9

Two principal issues have emerged in this review concerning TMLP's major generating unit: (1) Cleary 9's past outage record and (2) prospects for conversion of Cleary 9 from oil to natural gas or coal. The anticipated 1985 expiration date for the Montaup-Taunton agreement heightens the importance to TMLP of Cleary 9's reliability and efficiency.

1. Reliability

Availability factors of under 65% were experienced at Cleary 9 for each of the years 1980-82, and for the first six months of 1983. Informatin Return S-8. Several scheduled or unscheduled outages were required for boiler repairs and modifications to prevent future failures, and for repair and redesign of the steam turbine blades. Conversion of the 23MW combustion turbine to burn natural gas also accounted for a portion of the major outage periods in 1982 and 1983.

Significant steps appear to have been undertaken to prevent future failures, and TMLP has noted improved monthly availability factors, exceeding 90%, from May to September, 1983. TMLP has also pointed out that its purchases of unscheduled outage service from January 1980 to September 1983 were less than one percent of its energy sales in each year. Information Return, SS-3.

With the expiration of 20.27 MW of base load purchase contracts in late 1984, TMLP will become substantially more dependent on Cleary 9, and thus more vulnerable to any future outages and the costs of NEPEX outage service. Any evidence of continued availability problems due to plant failures will be viewed with concern by the Council. As a CONDITION to the approval of its 1983 Forecast, TMLP should report to the Council in its next filing on the effectiveness of its improvements to Cleary 9 in maintaining higher availability factors.

2. Fuel Conversion

As a result of increased availability of natural gas at competitive prices, TMLP has converted the 23 MW combustion turbine to burn natural gas supplied by Bay State Gas Company. Conversion of the 87 MW steam boiler to burn natural gas is under study as well. In addition, conversion of Cleary 9 to burn coal, under a unit contract with MMWEC, is one of several coal related supply options being considered by TMLP. See infra, Sec. E-4.

Under the present contract with Bay State, gas supplies are available on an interruptible basis, generally during the non-heating months. TMLP reported 1983 fuel cost savings of $708,985 through September as a result of substituting natural gas for oil. Information Return SS-5. The first year savings exceeded the $417,053 cost to convert the combustion turbine. Information Return SS-7.

With regard to the steam boiler, the cost of adding gas firing capability is estimated to be $1.2 million. This option is to be further evaluated when Bay State provides necessary pricing and availability data. Bay State's ability to offer off-peak gas to TMLP at a competitive price should be enhanced by the recent decision by the Federal Energy Regulatory Commission approving Phase I of the Boundary Gas Project. CP81-107-000 (et Seq.). This approval will provide Bay State with new gas supplies of nearly 20 million cubic feet per day over the next decade. In addition to the immediate costs of conversion and possible effects on boiler performance, TMLP expects to consider the extent to which natural gas conversion may affect its coal conversion options. Information Return SS-4, Exhibit SS4-1.

The Council finds the actual and prospective gas conversions to be potentially very valuable, in that they allow displacement of oil when gas is available and economically priced. Although only on a part-year basis, the conversions may also increase system flexibility to minimize vulnerability to disruptions in any one fuel supply. In addition, the prospects for reduced maintenance costs with use of natural gas are an important consideration. As a CONDITION for approval of its 1983 Filing, TMLP shall in its next filing provide an update on its plans to enhance the economic viability of Cleary 9.

E. Cost of the Seabrook Project

The TMLP has provided actual 1982 and estimated remaining annual (1983-1987) expenditures for its share of the construction costs for Seabrook 1 and 2. Information Returns SS-7, SS-8. Table 2 compares these costs with the corresponding estimates for the same years as provided in EFSC 79-51. 3 DOMSC 127. The estimated costs have roughly tripled since EFSC 79-51, both for the overall 1982-87 period and for the remaining latter four years of that period. In addition, the cost estimates provided have not been updated to reflect the delay of work on Seabrook 2 approved by the joint owners of the project in September, 1983.

The Council is concerned with the escalation in estimated construction costs for Seabrook. The Council expects that if the purchase of shares in Seabrook 2 is included in future filings, TMLP will indicate its individual position as a joint owner regarding the desirability of completing the unit. TMLP should also provide updated cost estimates.[6]

Table 2

TMLP's Share of Seabrook Construction Costs, Previous vs. Current Filing

	Actual or Estimated Cost	
Year	79-51	83-51
1982	$297,000	$553,458(actual)
1983	163,000	700,000
1984	172,000	611,300
1985	160,000	327,400
1986	83,000	257,000
1987	-	115,700
1982-87 total	875,000	2,564,858
1984-87 total	415,000	1,311,400

Information Returns SS-7, SS-8.
3 DOMSC 127. Exhibit I-2.

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6. See infra, footnote 9 for a discussion of the Council's continuing authority to review capacity purchases that were included in previously approved forecasts.

F. TMLP's Supply Planning Options

In this proceeding, TMLP has provided substantial indicia of its pursuit of supply planning options to provide a more economical and more diverse source of power during the forecast period. Information Return S-4. Exhibit S-14. Brief of TMLP, p.60-71. As indicated earlier, TMLP has set a goal of 30 MW of new non-oil base load generating capacity in order to displace oil and reduce oil dependence. Options currently being considered to help meet this goal include hydro, wood-fired, refuse-fired, coal-fired, and nuclear sources of energy, as well as the interruptible natural gas supplies discussed in the previous section. Conservation and load management approaches are also part of TMLP's supply planning to meet its diversification goal. See infra, Sec. H.

The TMLP is also pursuing a new 50 MW exchange contract with Eastern Utilities Associates (EUA) to provide unit and some fuel diversity through 1992. This could in large part replace base load purchase agreements for Canal II and Somerset, and the sales agreement for Cleary 9, that expire in the next two years.

A review of TMLP's supply planning options for hydro, wood-fired, refuse-fired, nuclear, and coal-fired sources follows.

1. Hydro Projects

Under recent NEPOOL support agreements, TMLP is entitled to 0.4%, or just under 3 MW, of the Phase I transmission capacity to import power from Hydro Quebec. The Phase I power contract would provide various forms of scheduled, non-scheduled and surplus energy to NEPOOL participants beginning in 1986/87. Capacity credits would not apply to Phase I. TMLP is also interested in Phase II of Hydro Quebec, which may provide additional power beginning in the 1990's.

Under DPU agreement, MMWEC is acting as representative for TMLP and other municipal electric light departments in Massachusetts concerning acquisition of power from the Niagara hydro projects owned by the Power Authority of New York State (PASNY). Limited "non-firm" power has been awarded through 1985, but is the subject of litigation at the Federal Energy Regulatory Commission (FERC). A PASNY-appointed administrative law judge has made post-1985 allocations of power that would provide 30.92 MW for Massachusetts utilities, of which TMLP's share would be about 0.3 MW.[7] It is unclear whether the final allocations will provide preference to municipals, which could increase municipals' shares significantly. MMWEC is pursuing such an allocation, and hopes to thereby increase its share by 980%.[8] Assuming such an increase for all Massachusetts municipals, TMLP could expect a share of just over 3 MW.

7. Power Authority of the State of New York, 1985 Neighboring State Hydroelectric Allocation Plan Proceeding, Recommended Decision by Presiding Examiner Edward L. Block, p.140. The allocations in Massachusetts are based on number of 1981 residential class customers.

In summary, TMLP is likely to have 3-6 MW of new hydro supply by 1986 through regionally available projects. However, the Phase I Hydro-Quebec option is expected to provide savings shares only, not capacity credit.

2. Burlington Wood-Fueled Project

TMLP is actively negotiating for an economic agreement to purchase 5-10 MW of power from the Burlington Electric Department wood chip plant in Vermont. The 53.8 MW plant is expected to be on line in March, 1984. Long term contracts with forest landowners are expected to provide stability in wood supplies and prices. Busbar costs are estimated to be $76/Mwh in 1985, and to escalate at 4-6% per year. Information Return SS-17. The rate of escalation is less than that expected for oil fuel costs, thereby providing potential long-term savings for TMLP. TMLP is seeking a longer-term contract than the ten-year offer by Burlington.

3. Millstone III Nuclear Project

A unit contract to purchase 4.2 MW of Millstone III capacity currently held by Burlington Electric Department in Vermont is under consideration by TMLP.[9] Information provided by TMLP indicates that such a purchase could involve prepayments and other arrangements to take over favorable financing for Burlington's capacity. The costs to TMLP of this option have not been determined. Information Return SS-10.

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8. See MMWEC Forecast Review, EFSC 82-1, Information Return, SSS-7, Exhibits 7(b), 7(c).

9. During the Forecast adjudication, TMLP objected to EFSC staff information requests concerning TMLP's purchase of Millstone and Seabrook capacity on the grounds that these purchases had been previously approved by the Council. The Council recognizes that Taunton's previously approved supply plan contained capacity purchases from these plants. However, the Council reminds TMLP that what was approved in EFSC 79-51 was a Long-Range Forecast. Applying the relevant standards set out in G.L., ch. 164, sec. 69J to TMLP's "then existing" forecast of resources and requirements, the Council was reasonably satisfied. The previous approval in no way precludes the Council from its inquiries into Taunton's present forecast so as to determine whether the situation as now exists continues to satisfy the EFSC's "consistently reasoned" standards. See Boston Gas Co. v. Department of Public Utilities, 367 Mass. 92, 324 N.E.2d 372 (1975). The Council can only reverse its previous pronouncements if it determines that circumstances have changed significantly enough to warrant such a change in posture. (See Procedural Order, EFSC No. 82-1, August 3, 1983).

4. Coal and Refuse Projects

Since EFSC 79-51, TMLP has conducted detailed analyses of coal and refuse fired capacity. Both separate and integrated facilities for utilizing the two fuels have been considered. Specific options have included the 50.8 MW IMERS (Integrated Municipal Energy Resource System) project at alternative sites, the 9.9 MW conversion of the West Water Street Plant (currently unused) to burn coal and refuse, and the 81 MW conversion of the Cleary 9 boiler to burn coal. Information Returns S-3, S-14. TMLP indicated in its brief that it is further studying a refuse-to-energy resource of an unspecified size and description. Brief of TMLP, p. 66.

The Cleary 9 coal conversion option is the most recent coal-related project to be analyzed in detail by TMLP, and appears to be the most economic. Figure 1 shows TMLP's comparison of the energy costs of the three options and Cleary 9 using oil. Fuel cost escalation rates are assumed to be 6% for coal and 8% for oil. Information Return S-3.

Because of its size, the Cleary 9 conversion has been jointly studied by MMWEC and TMLP. If undertaken, it would be financed by MMWEC; TMLP would purchase a portion of the energy under a unit contract. Information Return S-3. In light of the considerable compounding of interest built into the financing of past MMWEC projects, TMLP has also considered in Figure 1 the cost of Cleary 9 coal conversion without capitalization of interest costs (i.e., interest paid when due from operating revenues).

In developing its IMERS and Cleary 9 options, TMLP has assumed installation of wet scrubbers to remove 90% of the sulfur-dioxide from the expected air emissions. TMLP indicates that this removal rate reflects best available control technology, which would meet existing air emission standards and minimize the incremental effects on ambient air quality and acid rain. The public and agency comments on Boston Edison's 1983 Draft Environmental Impact Reports on proposed coal conversions at its New Boston and Mystic stations are an example of the increasing concerns being raised about possible acid rain impacts of coal-burning facilities. In that light, the Council commends TMLP for its efforts to provide best available control technology and address the acid rain problem.

The proposed refuse burning in both the IMERS and West Water Street options is based on 29,200 tons of refuse per year. A $5 per ton tipping fee was assumed for IMERS compared with $15 per ton for West Water Street -- the higher fee would reduce the overall cost of IMERS by only about one percent. In the IMERS study, it was also found that combined coal and refuse burning would be less expensive and would cause less corrosion than separate refuse-fueled generation.

Information Return S-3

EXHIBIT IV

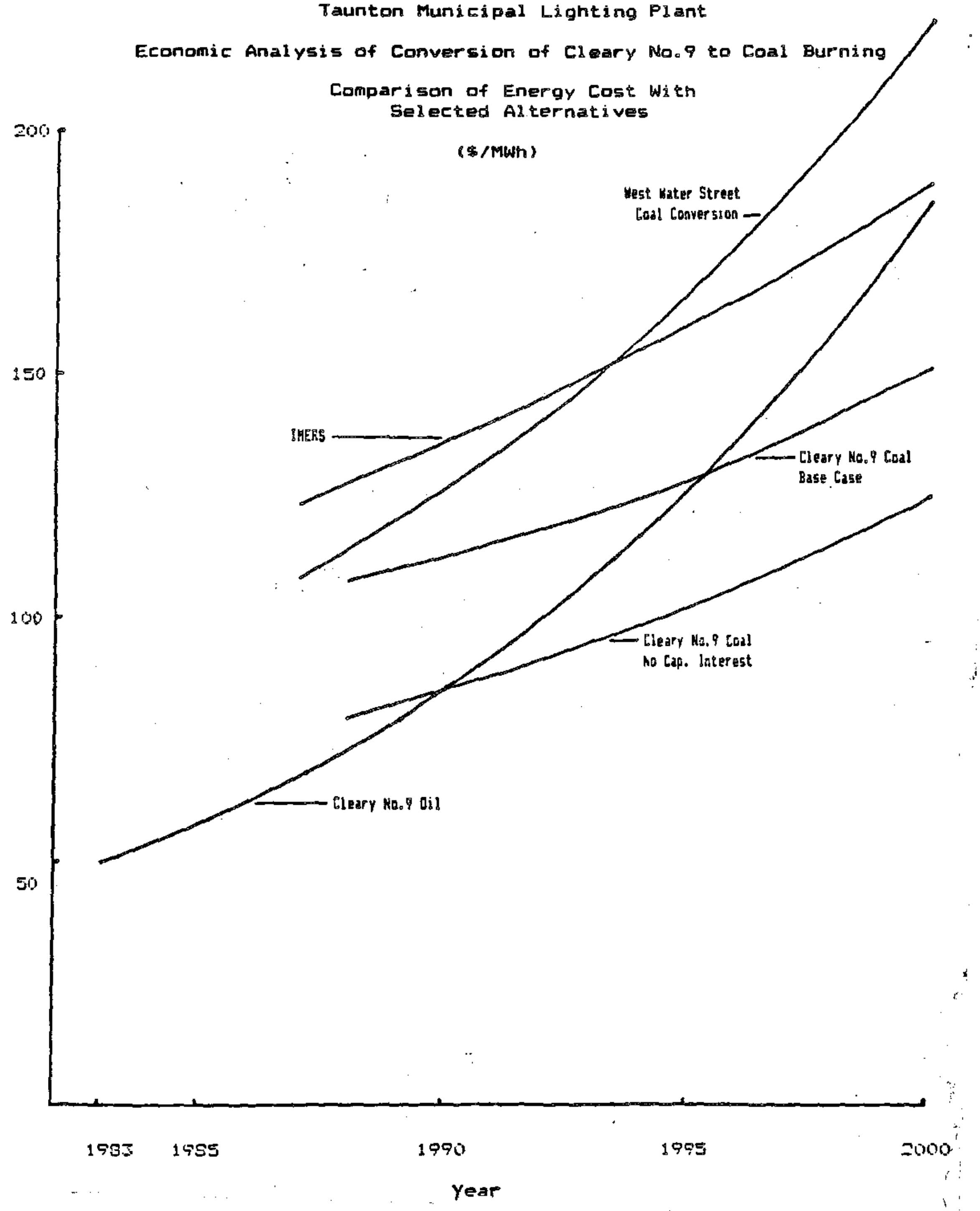
Figure 1

Taunton Municipal Lighting Plant

Economic Analysis of Conversion of Cleary No.9 to Coal Burning

Comparison of Energy Cost With Selected Alternatives

($/MWh)



The Council commends TMLP for the extent of its analysis of the individual options, and for the follow-up comparative evaluation as reflected in Figure 1. It is recognized that uncertainty about relative future fuel costs and the direction of national and state policy regarding acid rain complicate the evaluation of coal-related options. It is also noted that the start-up dates for these options are later than TMLP's hydro and wood-fueled options because of longer lead times. The relative time frame of TMLP's supply options is further reviewed in the summary section below.

The Council also strongly commends TMLP's attention to refuse burning opportunities in its detailed studies since EFSC 79-51. The further analyses of refuse burning alluded to in TMLP's Brief are also applauded. Brief of TMLP, p.61. In light of the variation in assumed tipping fees noted earlier, the Council is hopeful that TMLP can provide clearer evidence of the merits of refuse burning in terms of long term avoidance of refuse disposal costs for the City of Taunton. The viability and relative economics of a larger regional facility utilizing refuse from surrounding communities should also be considered.

5. Summary and Time Frame of Options

TMLP has identified four hydro, nuclear and wood-fired options which together may provide 12-20 MW of new non-oil capacity by 1985. TMLP has also analyzed three coal or coal/refuse projects, of 10-81 MW each, with projected start-up dates of 1987 or 1988. TMLP contends that various combinations of these options, together with consideration of the Cleary 9 boiler conversion to natural gas if implemented, could achieve its goal of 30 MW of new non-oil capacity by 1990. Information Return SS-2. See supra, Sec. B.

The Council notes that, to achieve its goal based on the above options, TMLP must either implement a coal-related project or implement and count the natural gas conversion. Although significant in displacing oil, the gas conversion should be recognized as only a part-year option. In some respects, then, implementation of a coal-related option may currently be viewed as important to achieving TMLP's goal.

It appears that the coal-related options are subject to longer lead times and greater uncertainties than TMLP's other pending options. In recognition of this distinction, TMLP should consider establishing a first-stage or interim goal for achieving the desired reduction in oil dependence. This is not to detract from the merits and significance of the longer term projects, but rather to recognize the range of predictability associated with the different options. The Council encourages continued close attention by TMLP to the relative timing and predictability of options for achieving more economic and diversified supplies.

G. Customer Owned Cogeneration and Renewables

The TMLP reports that, since 1980, it has been contacted by two TMLP customers interested in installing alternative energy systems. Both of these customers are now generating with windmills. The excess energy provided to the TMLP system by these windmills amounted to 1411 Kwh in 1982. Information Return S-15. No offers or inquiries from independent small power producers outside the TMLP service area have been reported.

The TMLP currently does not receive any cogenerated electric power and reports no known customer cogeneration in its service area. In 1981, thermal requirements of some customers were investigated in connection with possible distribution of cogenerated energy from the proposed IMERS project. See supra, Sec. F-5. TMLP has provided some technical assistance on cogeneration and parallel generation.

Under its Energy Services Planning Program, TMLP has reaffirmed the availability of technical assistance for development of renewables and cogeneration. The Council is concerned that TMLP should indeed be more agressive in promoting small power production than it has been prior to institution of the program. The availabiity of data in the IMERS study should provide an early opportunity and impetus for TMLP to begin actively promoting customer-owned cogeneration.

The Council notes that financing as well as technical information is an important concern for small power producers. In that light, it is suggested that TMLP consider instituting contractual policies that include minimum-floor-pricing opportunities for small power producers under appropriate circumstances. In addition to stimulating interest within its service territory, such policies could allow TMLP to become more competitive in attracting small power producers from outside its area.

As a CONDITION for approval of its 1983 Filing, TMLP shall investigate methods to help bring about increased purchases of customer-owned generation capable of providing a more economical and diversified supply plan, and report in its next filing.

H. Conservation and Load Management

The TMLP has participated in Bay State Gas Company's "Project H.E.A.T.", which provides an energy conservation service program in compliance with state regulations. As of May, 1983, 1285 energy audits had been conducted, with total expenditure of $37,922. Over $20,000 has been spent on public announcements and flyers, and free conservation devices and handbooks have been distributed. Information Return S-16. TMLP is switching to the "Mass Save" Program effective in 1984. Brief of TMLP, p. 73.

Important in-house conservation measures were installed at the Cleary 9 unit in 1983. These include a performance monitoring computer system for the plant and inlet modulating equipment for the combustion turbine unit -- together they are projected to save $500,000 per year. In addition, the Whittenton Junction Transmission line and substation, approved by EFSC in 1982, is projected to save 1450 Mwh per year in line losses. 8 DOMSC 161.

The potential for savings from load management in the TMLP system was investigated as part of the Municipal Electric Associaton of Massachusetts (MEAM) study. Information Return S-11. With surplus capacity, and oil dependence extending into the base load level, the study concluded that TMLP cannot reduce costs through load management. As a result, TMLP has not actively pursued implementation of load management concepts.

The conclusion of the MEAM study regarding TMLP's inability to benefit from load management suffers from at least two deficiencies. First, the conclusion appears to discount the degree to which TMLP's cost of service is less than the theoretical cost of its own load dispatch due to savings shares derived from actual dispatch by the New England Power Pool. Secondly, the study does not reflect TMLP's supply planning and related prospects for new capacity and energy purchases. In light of the long-term view of supply planning and TMLP's goals regarding diversification, the Council believes that TMLP should pursue load management initiatives capable of providing a more economical supply.

TMLP for its part has included conservation and load management in its new energy services planning program. As conceived by TMLP, energy services may include energy audits, conservation financing, energy efficiency use seminars, electric load management, and energy management systems. Information Return S-11. The Council encourages TMLP to consider state-of-the-art approaches to bring about more conservation under arrangements capable of benefitting both TMLP and individual customers -- shared savings from programs involving utility installed or third-party financed conservation measures are examples. TMLP has also indicated it may conduct appliance use surveys to gather data on particular energy demand categories such as space heating, domestic hot water, lighting and transportation. Information Return SS-16.

In light of the lead times for obtaining valid appliance survey results, the Council CONDITIONS the approval of TMLP's 1983 Filing with the requirement that it report in its next filing on its progress and/or plans regarding appliance-use surveys. TMLP also should demonstrate in future filings its consideration of conservation and load management strategies as part of the integrated supply planning approach proposed in this proceeding. See supra, Sec. C.

VI. DECISION AND ORDER

The Council hereby APPROVES the 1983 Forecast of the Taunton Municipal Lighting Plant subject to the following Conditions:

DEMAND

1. TMLP is required to test other econometric model formats beyond linear regression in its future filings. Such formats shall be attempted for all customer classes.

2. TMLP is required to test model runs incorporating residential customer characteristics such as personal income and household type and size in its future filings.

3. TMLP is required to demonstrate its further efforts and/or plans to explicitly reflect prices of electricity and conservation/load management trends in its future forecasts for the domestic hot water class.

4. TMLP is required to make a significant start toward disaggregating its current and future industrial sales data by 2-digit SIC code, and report its progress in the next and future filings.

SUPPLY

1. TMLP is required to report to the Council in its 1984 Filing on the effectiveness of its improvements to Cleary 9 in maintaining availability factors.

2. TMLP is required to provide in its 1984 filing an update on its plans to enhance the economic viability of Cleary 9.

3. TMLP is required to investigate methods to help bring about increased purchases of customer-owned generation capable of providing a more economic and diversified supply plan, and report in its 1984 filing.

4. TMLP is required to report on its progress and/or plans regarding appliance-use surveys in its 1984 Filing and is required to demonstrate its consideration of conservation and load management strategies as part of an integrated supply planning approach in all of its future filings.

The 1984 Forecast Supplement will be due on October 1, 1984.

Energy Facilities Siting Council

By ______________________

Lawrence W. Plitch, Esq.
Hearing Officer

Unanimously APPROVED by the Energy Facilities Siting Council on March 5, 1984 by those members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs); Walter Headley (for James S. Hoyte, Secretary of Environmental Affairs); Joellen D'Esti (for Evelyn F. Murphy, Secretary of Economic Affairs); Robert W. Gillette (Public Environmental Member); Thomas J. Crowley (Public Member Engineering).

13 March 1984
Date

Sharon M. Pollard
Sharon M. Pollard
Chairperson

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: 1983 through 1988	EFSC No. 83-25

FINAL DECISION

Lawrence W. Plitch, Esq.
Hearings Officer
March 5, 1984

On the Decision:
George Aronson
Lead Gas Analyst

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LIST OF TABLES AND FIGURES

The Council hereby APPROVES conditionally the Second Supplement to the Second Long-Range Forecast of Gas Needs and Requirements, 1983-88, ("Forecast") of the Boston Gas Company et al ("Boston Gas" or "the Company"). This decision is divided into seven sections, each of which discusses salient aspects of the adjudication of the Forecast. Following this introduction, we describe the Company and its characteristics in Section I; the history of the adjudication in Section II; compliance with the Conditions imposed in our last Decision in Section III; evaluate the forecast of sendout requirements in Section IV; review the Company's resources in Section V; compare resources to sendout requirements in Section VI; and issue our Decision and Order in Section VII.

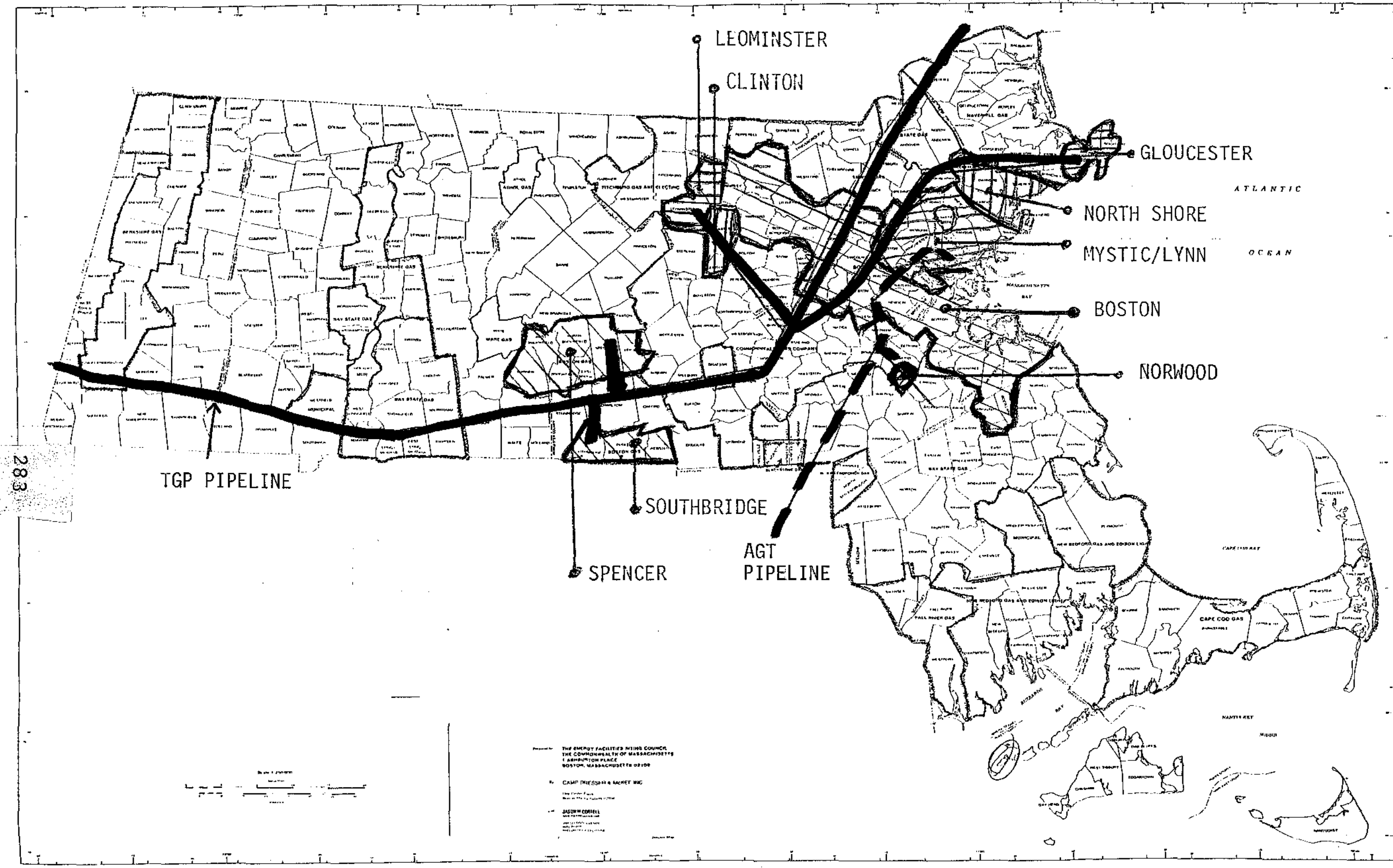
I. BACKGROUND OF THE COMPANY

Boston Gas distributes and sells natural gas to residential, commercial, and industrial customers in the City of Boston and 73 other Massachusetts communities. It is the largest gas distribution utility in the Commonwealth, with over 500,000 customers and firm sendout of more than 65000 million cubic feet (MMcf) of gas per year. The Company is the sole supplier of gas to the Wakefield Municipal Gas Company and to a number of interruptible customers. The Company also sells gas to the Lowell Division of the Colonial Gas Company and exchanges gas with the Cambridge Division of the Commonwealth Gas Company through pipeline interconnections between their distribution systems. Finally, Boston Gas provides displacement services to a number of gas companies that contract for LNG with the Distrigas of Massachusetts Corporation ("DOMAC"), whose LNG terminal and tanks are located within Boston Gas's service territory.

All of Boston Gas's capital stock is held by Eastern Gas and Fuel Associates ("Eastern"), which is headquartered in Boston. Eastern owns 36.8% of the outstanding stock of Algonquin Energy, Inc. ("Algonquin"), which is the parent company of Algonquin Gas Transmission Company ("AGT"), Boston Gas's largest supplier of pipeline gas, and the parent of Algonquin SNG, Inc., a supplier of synthetic natural gas from naphtha feedstock. Boston Gas has one subsidiary, Massachusetts LNG, Inc., which holds long-term leases on two liquefied natural gas (LNG) storage facilities. Boston Gas also owns 11.2% of the outstanding stock in Boundary Gas, Inc., a close corporation formed to purchase and import natural gas from Canada.

Boston Gas's service territory is divided into nine operating divisions. Seven are served only by the Tennessee Gas Pipeline Company's (TGP) pipeline, one is served only by AGT's pipeline, and one is served by both the TGP and the AGT pipelines. Figure 1 shows a map of Boston Gas's operating divisions and the interstate pipelines that serve them.

FIGURE 1. BOSTON GAS COMPANY SERVICE TERRITORY.



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II. HISTORY OF THE PROCEEDINGS

The Company's Second Annual Supplement to the Second Long-Range Forecast ("Forecast") was timely received by the Council on July 1, 1983. The Notice of Adjudicatory Proceeding and Prehearing Conference was published by the Company once a week for three consecutive weeks during July and August of 1983 in the Boston Globe, the Boston Herald American, the Middlesex News, the North Shore Sunday and the Worcester Telegram. In addition, the Notice was sent by certified mail to the 74 cities and towns in the Company's service territory and by regular mail to the Council's Adjudicatory List.

The Council received no petitions to intervene prior to the August 17, 1983, deadline, and a Prehearing Conference was held on August 18, 1983, with the staff of the Council and the Company in attendance. There being no new facilities proposed and no intervenors, it was decided to adjudicate this case through informal technical sessions rather than adversarial proceedings. The first of these technical sessions was held on August 23, 1983, and several more were held during the subsequent months (See Procedural Order, August 23, 1983.). The first set of Staff Data Requests was issued to the Company at the August 18, 1983, Prehearing Conference, and initial responses were received on September 28 and 30, 1983. On October 6, 1983, the Hearing Officer issued a Protective Order granting confidentiality to certain proprietary documents that the Company submitted in response to a Staff Information Request. The documents were the latest in a series of marketing studies, earlier editions of which had been granted identical protection in the Council's last review of a Boston Gas forecast (See Protective Order, EFSC No. 82-25, October 13, 1983). Additional record information was provided by the Company in response to staff inquiries throughout the months of November and December, 1983. The record was closed on December 16, 1983.

On December 6, 1983, the Council received a Late Filed Petition to Intervene from the Distrigas of Massachusetts Corporation ("DOMAC"). After allowing for and receiving on December 13, 1983, a Protest of Petition of DOMAC to Intervene from the Boston Gas Company, the Hearings Officer rejected in part and allowed in part DOMAC's petition (See Procedural Order, December 20, 1983). DOMAC was granted Interested Person status and the right to present oral arguments and submit a brief to the Hearings Officer prior to the issuance of a Tentative Decision. The Hearings Officer was informed by letter on January 5, 1984, that DOMAC, having reviewed the record in this case, would decline to exercise the above noted rights. DOMAC, however, reserved its right, pursuant to EFSC Rule 16.4, to submit to the Council written comments and arguments in response to the Tentative Decision. Finally, pursuant to EFSC Rule 16.4(2), DOMAC also has the right to move the Council, within its discretion, to hold a hearing concerning the Tentative Decision.

III. PREVIOUS CONDITIONS

The Council's Decision in review of the Company's First Supplement to the Second Long-Range Forecast of Gas Needs and Requirements ("1982 Forecast") In Re Boston Gas, 9 DOMSC 1, 110-112 (1983), imposed eleven Conditions, as follows:

(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 [base] 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;[1]

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1 Condition 5 to our 1981 forecast review, In Re Boston Gas Company, 7 DOMSC 1, 78 (1982), restated in the 1982 review as Condition 9, was as follows:

"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."

(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.

Pursuant to Condition 11, the Company met with Council staff on December 10, 1982, to discuss compliance with the other ten Conditions. The results of that meeting are outlined in a memorandum to file, attached hereto as Attachment A.

The Company addresses each Condition individually in Appendix A of its filing. The Company justifies its 0% conservation rate in compliance with Conditions 1 and 2, and describes its use of its conservation data bases in compliance with Condition 3. As directed by Conditions 4 and 5, the Company provides tables of the base load factors and heating increments used in the forecast, and describes in detail the new process by which they are updated. The Company estimates peak sendout by division as required by Condition 6, and forecasts commercial and industrial consumption separately as required by Condition 7. During the discovery process, the Company provided consumption data disaggregated by SIC code. It also responded to staff inquiries as to the Company's use of supplemental supplies to meet sendout peaks (Condition 8), including the status of the new Spencer propane facility (Condition 10). Finally, the Company helped staff to understand the Company's displacement arrangements (Section V.B.3) and interconnections with other gas companies (Section I), thereby shedding light on the potential regional impacts of the Company's operations in the event of a cessation of deliveries of Algerian LNG (Condition 9).

We are satisfied that the Company has complied with all of the eleven Conditions to our previous Decision, though we remain concerned with several aspects of the Company's forecast. We discuss our remaining concerns with the Company's modeling of conservation in Sections IV.B.2, IV.B.3, and I.V.B.4., infra. The regional impacts of the Company's operations are analyzed in the context of the cold snap discussion in section VI.C.2, infra. The Company's compliance with Conditions 4, 5, 7, 6 8, 9 and 10 is analyzed in detail in sections IV.B.2, IV.B.1.b., IV.B.2.c., VI.B, VI.c, V.B.3, and V.B.4., infra.

The Council is pleased with the Company's efforts to improve its forecast methodology, and with the Company's direct and thorough responses to staff Data Requests. The Company has documented its calculation methods and judgements in great detail. Indeed, Boston Gas has set a standard of reviewability that other large gas companies would do well to emulate. We hope and expect that the Company will maintain this high level of effort in future filings with the Council.

To maintain reviewability, we request that the Company continue to provide back-up data at the time of its initial filing. Specifically, we request that the Company provide the base load factors and heating increments in same format as were provided this year; a sample calculation that shows how the base load factors and heating increments are updated; estimates of peak load by division; load growth targets; and the end-use assumptions that are used to allocate load growth among customer classes.

IV. FORECAST OF SENDOUT REQUIREMENTS

A. Description of Forecast Methodology

To forecast sendout requirements, Boston Gas combines management judgements on supply availability and the nature of load growth with elements of end-use modeling. Company judgements on supply availability determine the allowed rate of load growth and its expected temperature-sensitivity. Company judgements on the nature of the new load are used to calculate "base load factors" and "heating increments" to forecast daily usage and peak day sendout. Elements of end-use modeling are used to allocate load growth among customer classes, and to insure that target levels of load growth and temperature-sensitivity can be achieved.

The forecast of sendout is produced in five steps. First, the Company selects a target rate of load growth for its entire system, which results in a target amount of load to be added in MMCF per year. Next, Boston Gas estimates the temperature-sensitivity of its load growth, as well as the amount that will occur in the heating vs. non-heating seasons. The Company now has four load growth targets for each forecast year: base load growth during the heating season, base load growth during the non-heating season, temperature-sensitive load growth during the heating season, and temperature sensitive load growth during the non-heating season.

In a third step, Boston Gas calculates a new set of base load factors and heating increments for each year. To calculate new base load factors, the Company divides the seasonal base load growth targets (in MMcf) by the number of days per season, and adds the results (in MMcf per day) to the base load factors from the previous year. To calculate new heating increments, Boston Gas assumes that all of its temperature-sensitive load growth occurs during the heating season. The Company continues to use six heating increments (in MMcf per degree-day), corresponding to six customer usage patterns under different winter weather conditions.[2] Boston Gas increases each of the six heating increments in each heating season such that the total load added in all degree-day ranges equals the temperature-sensitive load growth target (in MMcf), while the individual heating increments remain in constant proportion to each other (See Section IV. B.2, infra).

Next, Boston Gas runs its ABCGAS dispatching model. The model combines weather data, base load factors, heating increments and supply data to determine how supplies can best be used to meet daily and peak sendout requirements. The model also yields a forecast of allowable interruptible sales under normal weather conditions.

Finally, Boston Gas computes the number of customers and amount of

2 See 9 DOMSC 1, 16 (1983).

load it will need to add in each class (residential, commercial, etc.) to meet its load growth and temperature-sensitivity targets. Here, the Company makes explicit assumptions about the end-use requirements of each class (e.g., 105 Mcf per newly-converted heating customer per normal year). The load data from this analysis is added to normalized historical data to produce Tables G-1 through G-5.

Table 1 shows Boston Gas's forecast of sendout requirements by customer class for the first and last years of the forecast period.

TABLE 1
Forecast of Sendout by Class
Normal Year
(MMCF)

	1983-84		1987-88	
Class	Non-heating Season	Heating Season	Non-heating Season	Heating Season
Residential Heating	10356	21172	10449	21770
Residential Non-heating	2548	2243	2490	2199
Commercial	7363	12154	7559	12887
Industrial	1867	2655	2140	2862
Wakefield	111	229	113	273
Company Use and Unaccounted for	(559)	6500	(526)	6598
Total Firm Sendout	21685	44953	22225	46589
Interruptible	20283	1741	6907	1487
Total Sendout	41968	46694	29132	48076

Source: Forecast, Tables G-1 through G-5; EFSC 83-25 Response to Data Request SR-3 (corrections to filed tables).

B. Analysis of Forecast Methodology

This section reviews the judgements made by Boston Gas to produce its forecast. Specifically, we review the Company's judgements in determining the rate and temperature-sensitivity of load growth; in computing the heating increments and base load factors; and in allocating load growth by class. We then compare the Company's forecasting methodology with more traditional econometric and end-use forecasting approaches. Throughout the review we emphasize those aspects that reflect changes from the Company's previous filing and information that is newly available to the Council.

1. Rate and Temperature-sensitivity of Load Growth

a. Load Growth Assumptions

Boston Gas states that the rates of load growth used in their sendout forecast are based on a "management decision."[3] The Company forecasts a growth rate of 1.3% for 1983-84, and 0.8% for each year thereafter. These growth rates reflect the Company's desire "for a modest increase in growth while maintaining the ability to respond to changing customer consumption behavior."[4] The growth rates also reflect the Company's stated policy to confine load growth to levels which "absent winter deliveries of Distrigas [LNG] during a design year would not require the Company to process more than 50 million gallons of propane."[5]

The Council agrees that the Company's stated load growth rates are modest and reasonable, especially at a time of substantial uncertainty about future gas prices and customer usage patterns. Moreover, the Council is pleased that the Company continues to analyze how potential market disruptions or changes in load growth assumptions might affect its sendout forecast.[6] Ultimately, though, the validity of management decisions on load growth depends on the validity of the Company's assumptions regarding supply availability and the nature of the added load - assumptions that are reviewed throughout this Decision.

b. Temperature-sensitivity Assumptions

Boston Gas states that "[a]ssumptions regarding temperature sensitive load additions are based on management judgements and not on quantitative analysis."[7] The Company forecasts that 60% of the load added in 1983-84, and 55% of the load added thereafter, will be temperature-sensitive. The Company further states that, in each year over the forecast period, temperature-sensitive load will increase its requirements only during the heating season. About 45% of the new base load will increase requirements during the heating season; the rest of the new base load will increase non-heating season requirements. These projections reflect discussions with field marketing personnel, as well as general assessment of potential new construction activity and price relationships with competitive fuels.[8]

3 EFSC 83-25, Response to Data Request SR-2.
4 Forecast, S.1, at 18.
5 Response to Data Request SR-21.
6 Forecast, S.1, at 18, Note 4.
7 Response to Date Request SR-5.
8 Forecast, S.1, p. 26; Response to Data Requests SR-5.

Table 2 shows the actual load growth targets that result from the Company's judgements on the rate and temperature-sensitivity of load growth, and that are used to calculate base load factors and heating increments.

TABLE 2
Load Growth Targets
(MMCF)

Split Year	Season	Base Load Volumes	Temperature Sensitive Volumes	Total
1983-84	Non-heating	208	0	208
	Heating	149	497	646
	Total	357	497	854
1984-85	Non-heating	135	0	135
	Heating	101	304	405
	Total	236	304	540
1985-86	Non-heating	135	0	135
	Heating	103	310	413
	Total	238	310	548
1986-87	Non-heating	135	0	135
	Heating	103	306	409
	Total	238	306	544
1987-88	Non-heating	135	0	135
	Heating	103	306	409
	Total	238	306	544

Source: Forecast, S.1, Table 3, at 27. Gross sales additions are increased by 6% to adjust for unaccounted-for gas.

The Company has changed its judgements regarding the amount of new load that is temperature-sensitive since its last Forecast. In its last review, the Council was critical of the Company's assertion that "90% of the total load added will be temperature-sensitive."[9] The Council believes that the Company's current assumptions are more representative of its load growth, which is a mix of residential, commercial, and industrial load. Ultimately, the validity of the Company's judgements on temperature-sensitivity depends on its ability to market gas to new customers as anticipated. See Section IV. B.3, *infra*.

9 9 DOMSC 1, 35 (1983).

The Company has also changed its judgements regarding temperature-sensitive load growth and conservation in the non-heating season. Last year, the Company calculated the amount of temperature-sensitive load growth in the non-heating season by using the historical ratio of base load sendout to total seasonal sendout; this year, the Company assumes that none of the temperature-sensitive load growth occurs during the non-heating season. Last year, the Company used a conservation rate of 1.5% during the non-heating season; this year, the Company uses a 0% conservation rate.[10] Both judgements are justified as being "conservative": the 0% conservation rate, because the Company "places a low level of confidence in conservation projections;"[11] the decision to allocate all temperature-sensitive load growth to the heating season, because the Company faces greater risk in its ability to serve its existing customers under design winter weather conditions than under design non-heating season weather conditions.[12]

The Council is concerned about the Company's decision to account for temperature-sensitive load during the heating season, but not during the non-heating season. Presumably, if Boston Gas adds temperature-sensitive loads, there will be temperature-sensitive load growth in both the heating and non-heating seasons. For non-heating system load to occur as forecast, existing load must decrease by the same amount that the new load adds: e.g., through conservation, attrition, or other methods. However, the Company explicitly states that no conservation is accounted for in the Forecast. Thus, the Company appears to be inconsistent in its treatment of non-heating season temperature-sensitive load growth.

We recognize that the magnitude of the inconsistency is small.[13] Nevertheless, inconsistent treatment of load growth diminishes the level of confidence that can be accorded to the Company's forecast. Through excess conservatism, these assumptions may overstate the temperature-sensitivity of heating season load growth and, as a consequence, overstate the magnitude of peak day sendout. The present method may introduce biases into the Company's forecast. The Council believes that uncertainties in the timing of temperature-sensitive requirements are better addressed through sensitivity studies.

The Council therefore ORDERS the Company to correct the inconsistencies in its treatment of non-heating season temperature-sensitive load growth in its next filing. The Company should distinguish between temperature-sensitive load growth and decreases in temperature-sensitive consumption by existing customers during the non-heating season, and should document its assumptions. Moreover, if the Company implicitly assumes that conservation will

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10 1982 Forecast, S.1, at 23, 26; Forecast, S.1, at 25.

11 Id., at 24.

12 Response to Data Request SR-7.

13 The Forecast implies that 67.476 MMcf of non-heating season temperature-sensitive load would be added if existing customers do not decrease their temperature-sensitive gas consumption. See Response to Data Request SR-7.

occur, or if it accounts for conservation in its variable heating increment algorithm, the amount or rate of conservation should be stated explicitly. This Order is appended to this Decision as Condition 1.

The Council is also concerned about the Company's decision to use a 0% conservation rate. These concerns are best expressed in the context of reviewing how the Company calculates its base load factors and heating increments. See Section IV. B.2., infra.

2. Calculation and Usage of Base Load Factors and Heating Increments

Table 3 shows the base load factors, heating increments, and formulas that Boston Gas uses to predict daily firm sendout and to forecast seasonal and peak day requirements. In accordance with the "Daily Sendout Analysis",[14] Boston Gas uses different heating increments and base load factors in the heating and non-heating seasons, and uses different heating increments for different degree-day ranges. The heating increments increase as the weather gets colder (and as the degree-day total rises), thereby reflecting the Company's observations of disproportionate increases in sendout on cold days.

To calculate firm sendout on any particular day, the degree-day total for that day is multiplied by the appropriate heating increment. The results are added to the daily base load factor. To calculate firm sendout for any particular season, the number of degree-days in each degree-day range for each season is multiplied by the appropriate heating increment. The results from all of the degree-day ranges are added to the product of the daily base load factor and the number of days per season. The Company assumes that a normal year contains 5758 degree-days and that a design year contains 6300 degree-days. The cumulative distribution of these degree-days over the degree-day ranges during the heating season is shown in Table 5, infra.

By providing the base load factors, the heating increments, and a full description of the method by which seasonal sendout is calculated, the Council is satisfied that Boston Gas has complied with Condition 4 to its previous Decision and Order. The Council commends the Company for the clarity and thoroughness of its description of its calculation procedures.

Boston Gas calculated its base load factors and heating increments on the basis of its load growth targets, actual 1981/82 sendout data, assumptions on the allocation of temperature-sensitive load growth among the heating increments that correspond to the various degree-day ranges, and assumptions on changes in the usage patterns of existing customers. The selection of load growth targets was reviewed in Section IV. B.1., supra; the other bases for the calculations are reviewed in the sections that follow.

a. Use of 1981/82 data

Boston Gas bases its calculations on actual sendout data from the 1981/82 heating season, not the 1982/83 heating season. The Company justifies its decision not to use the most recent data "..in light of

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14 1982 Forecast, Appendix B. See also 9 DOMSC 1, 16 (1983).

TABLE 3

Base Load Factors and Heating Increments by Degree-day Range

A. Heating Season

Split Year	Base Load Factor (MCF/Day)	Heating Increments (MCF/Degree-Day) 0-10	10-20	20-30	30-40	40-50	50+
1983-84	65.597	7.170	7.170	7.640	7.720	8.050	8.270
1984-85	66.269	7.229	7.229	7.705	7.788	8.120	8.347
1985-86	66.941	7.292	7.292	7.773	7.856	8.191	8.420
1986-87	67.613	7.355	7.355	7.840	7.924	8.262	8.493
1987-88	68.285	7.418	7.418	7.907	7.992	8.332	8.566

B. Nonheating Season

Split Year	Base Load Factor (MCF/Day)	Heating Increments (MCF/Degree-Day) April - August 0-10	April - August 10-20	April - August 20-30	September - October 0-10	September - October 10-20	September - October 20+
1983-84	65.500	6.08	5.47	7.16	4.47	6.57	7.29
1984-85	66.131	6.08	5.47	7.16	4.47	6.57	7.29
1985-86	66.762	6.0	5.47	7.16	4.47	6.57	7.29
1986-87	67.393	6.0	5.47	7.16	4.47	6.57	7.29
1987-88	68.024	6.0	5.47	7.16	4.47	6.57	7.29

C. Formula for Firm Daily Sendout

$$\underset{\text{(MCF/Day)}}{\text{Firm daily sendout}} = \underset{\text{(MCF/DD)}}{\text{Heating increment}} \times \underset{\text{(DD/Day)}}{\text{Daily DD total}} + \underset{\text{(MCF/Day)}}{\text{Daily base load factor}}$$

D. Formula for Firm Seasonal Sendout

$$\underset{\text{(MCF/Season)}}{\text{Firm seasonal sendout}} = \left(\underset{\text{(MCF/Day)}}{\text{Daily base load factor}} \times \underset{\text{(Days/S)}}{\text{Days per season}} \right) + \sum_{i=1}^{\text{Number of HI's}} \left(\underset{\text{(MCF/DD)}}{\text{Heating increment}_i} \times \underset{\text{(DD/S)}}{\text{DD per DD-range per season}_i} \right)$$

Source: *Forecast*, Appendix A, p. A-12; Response to Data Request SR-1.

the 'warmness' of the past heating season in terms of total degree days deviation from normal and the few extremely cold days experienced."[15] The period from October, 1982, to March, 1982, contained 4321 degree-days, only 33 degree-days more than the warmest recorded since 1929, and 10.7% less than the Company's normal degree-total for that period. Fearing that data from an abnormally warm winter could yield a distorted picture of sendout patterns, the Company chose to use data from a recent winter that had weather that was closer to normal. Thus, the Company estimates the amount of load growth that would have occurred in 1982-83 under normal weather conditions (407 MMcf), updates its actual 1981-82 base load factors and heating increments to account for 1982-83 load growth, then calculates data for the forecast period from its estimated 1982/83 data.[16]

The Council recognizes that sendout data analysis and evaluation are difficult tasks, especially when the data are clouded by abnormal weather patterns and unusual consumer behavior. We therefore believe the Company has adequately justified its usage of 1981/82 data in place of 1982/83 data. However, we urge the Company to continue to dedicate resources toward the understanding of consumer behavior in all types of weather so as to make better use of all available data.

b. Allocation of temperature-sensitive load growth.

In this Forecast, Boston Gas uses a new methodology to account for temperature-sensitive load growth in its heating increments. As Table 4 demonstrates, the Company begins by calculating the average increase in temperature-sensitive load per degree-day for each heating season. The Company then designates the 30-39.9 degree-day range as a reference range, because the average mean daily temperature over a normal heating season is 35°F, which corresponds to a 30 degree-day day.[17]

The Company computes the ratio of the previous year's heating increment in each range to the previous year's heating increment in the reference range. These ratios are multiplied by the average increase in load per degree-day, yielding the increase in the heating increment for each range. The heating increment for the next year is the sum of the previous year's heating increment and the calculated increase in heating increment for that range.

Table 5 compares the load added by degree-day range under normal and design conditions for three cases; the method from the 1983 forecast, method from the 1982 forecast, and actual data between 1976/77 and 1981/82.

The new method appears to be an improvement. In its last Decision, the Council ordered the Company to modify its previous method for updating its heating increments, because it appeared to add too much load in the 40-50 DD range while underestimating the impact of load growth on peak day sendout.[18] Using the new method, more load is added

15 Forecast, at A-11.

16 Id., at A-14.

17 Forecast, at A-14. Thirty five degrees is the result of dividing 4517 degree-days by 151 days per heating season.

18 9 DOMSC 1, 48 (1983).

TABLE 4

Calculation of New Heating Increments

A. Calculate average load increase per degree-day due to temperature-sensitive load growth.

Heating Season	(A) Temperature-sensitive load growth (MMcf)	(B) Number of normal year degree-days	(C) = (A) / (B) Average Load Growth Increase per degree-day (MMcf/DD)
1982-83	407	4517	.0901
1983-84	497	4517	.1100
1984-85	304	4517	.0673
1985-86	310	4517	.0686
1986-87	306	4517	.0677
1987-88	306	4517	.0677

B. Adjust average increase per degree-day by degree-day range to update the heating increments (sample year).

DD Range	(D) 81/82 Actual increment (MMCF/DD)	(E) Ratio of HI to reference HI	(C) Average load growth per dd	(F)=(E)x(C) Increase in HI due to load growth (MMCF/DD)	(G)=(D)+(F) New HI (MMCF/DD)
0- 9.9	6.98	$\frac{6.98}{7.52}$ = 0.9282	0.0901	.0836	7.06
10-19.9	6.98	0.9282	0.0901	.0836	7.06
20-29.9	7.44	0.9894	0.0901	.0891	7.53
30-39.9	7.52	1.0000	0.0901	.0901	7.61
40-49.9	7.84	1.0426	0.0901	.0939	7.93
50+	8.06	1.0718	0.0901	.0966	8.15

Source: _Forecast_, at A-15. See also Tables 2 and 3, _supra_.

in the 20-30, 30-40, and 50+ (peak) DD ranges, and less load in the 40-50 DD range, than was added using the 1982 method. Moreover, the distribution of new load among degree-day ranges using the 1983 method approximates the actual experience between 1976/77 and 1981/82 more closely than does the distribution that uses the 1982 method.

The 1983 method also has intuitive appeal. By using the ratios of the heating increments in each degree-day range to the reference heating increment to allocate load growth among the ranges, the Company implicitly assumes that temperature-sensitive load additions will vary with outside temperature in the same way as existing load. The Company has stated that it

> "...does not have any indication that temperature-sensitive new load additions will behave any differently, with respect to outside temperature, than does existing load."[19]

There is no *a priori* reason to accept the five-year average data as representative of future customer behavior patterns; it is reasonable to use a methodology that yields results that differ somewhat from historical data.[20]

The Council notes that the Company bears the burden of showing that its assumptions are reasonable. The new method for updating the heating increments could be viewed with more confidence if it were confirmed by reference to disaggregated data (IV.B.4.b. *infra*). Still, we believe that the new methodology is an improvement over the previous one, and that the Company has complied with Condition 5 to our last Decision.

c. Changes in usage by existing customers

"The Company is using a 0% conservation rate for each individual class for each year of the forecast period."[21] The Company's load growth targets do not account for gas made available by conservation (IV. B.1., *supra*). The 0% conservation decision is apparent in the Company's method for updating its base load factors and heating increments. The Company uses its "springboard" 1981/82 factors adjusted for load growth to model existing load throughout the forecast period without accounting for reductions in usage by existing customers.

The Company has presented evidence that its existing customers are reducing their gas consumption - evidence that appears to contradict its decision to use its springboard factors without modification over the forecast period. The Company receives regular reports on the gas consumption of a large sample of its residential customers. The reports based on Company billing data, indicate that "customers have been conserving at the rate of approximately 1.5% per year."[22] Two analyses of daily sendout data show that normalized sendout during 1982-83 was 1.22% and 1.4% less than had been forecast assuming no conservation during the heating season.[23] These estimates of decreases in gas

19 Response to Data Request SR-6.
20 9 DOMSC 1, 48 (1983).
21 Forecast, Appendix A., at A-1.
22 Forecast, S.1. at 24.
23 *Id.*, p. A-10.

TABLE 5

Comparison of Methods to Allocate Temperature-Sensitive Load Growth by Degree-day Range

A. Normal Heating Season

DD Range	Degree-days in Range	Percent of Load Added by DD Range: 1983 Forecast	1982 Forecast	Actual Data
0-10	23	0.47	0.00	0.00
10-20	322	6.60	10.92	1.39
20-30	1285	28.05	15.57	23.06
30-40	1646	36.34	15.95	33.62
40-50	967	22.25	56.23	30.82
50+	274	6.49	1.33	11.80
	4517	100.0	100.0	100.0

B. Design Heating Season

DD Range	Degree-days in Range	1983 Forecast	1982 Forecast	Actual Data
0-10	0	0.00	0.00	0.00
10-20	264	4.77	8.39	0.94
20-30	1152	23.41	13.15	16.96
30-40	1676	34.05	15.19	28.08
40-50	1098	22.31	59.86	28.71
50+	761	15.46	3.40	25.31
	4951	100.0	100.0	100.0

Source: 9 DOMSC 1, 21, 22, 43, 47 (1983); Forecast, Appendix A, at A-12 - A-16. Table D-2 of the 1982 Decision, 9 DOMSC 1, 22, (1983) explains the calculation methodology behind the table.

consumption by existing customers are supported by similar studies in other Massachusetts gas company forecasts.[24]

Boston Gas acknowledges the apparent contradictions between the evidence on reduced consumption per customer and its 0% conservation decision, and justifies its decision on several grounds. It states that

> "[a]lthough the Company has seen fairly stable levels of incremental conservation over the past three heating seasons (approximately 1.5% per year), it places a low level of confidence in conservation projections..."[25]

and that

> "...customer consumption patterns fluctuate too much in the short run to allow for normalized consumption comparisons."[26]

The Company has shown that there is no simple relationship between gas prices and conservation rates, that changes in consumption per customer vary with such factors as the price of heating oil, the price of gasoline, patriotic spirit, and the severity of the weather, and that disproportionately little gas conservation occurs on extremely cold days.[27] Moreover, the Company has taken several steps to collect data on customer behavior, including maintenance of its residential and commercial conservation data bases, monitoring of daily sendout data, and initiation of a project to read the meters of a small sample of customers on a weekly basis.

Furthermore, the Company questions the need to account for conservation during off-peak periods. As Boston Gas has stated:

> "...[S]ince the Company is primarily concerned with design year planning, the usage patterns in the lower degree day ranges are somewhat insignificant. First, only about 5% of design heating season degree days fall within the 0-10 and 10-20 degree day intervals. Secondly, these warmer days do not require the use of supplemental peak shaving supplies."[28]

The Council is not convinced that the Company has justified its decision to use a 0% conservation rate. We believe that the record provides sufficient basis to forecast that customers will reduce their average annual consumption at some point during a design year, even if consumption increases disproportionately during extended periods of extreme cold. The Company's own data show annual reductions of 1.0% in

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24 For example, see EFSC 83-61, 1983 Colonial Gas Company Forecast. p. C-9; EFSC 83-13, 1983 Bay State Gas Company Forecast, Exhibit 2.

25 Forecast, p. A-3.

26 Response to Data Request SR-8.

27 Response to Data Request SR-9; Forecast, at A-3.

28 Response to Data Request SR-8.

1980/81, a normal winter containing an extended period of extreme cold, and 1.5% in 1982-83, a warmer than normal winter.[29]

Moreover, we believe that the impact of reductions in usage per customer on the reliability of the forecast is too important to be ignored. Though only 5% of design heating season degree-days fall within the 0-10 and 10-20 degree day intervals, 57.1% of design heating season degree-days fall within the 20-30 and 30-40 degree day intervals.[30] Supplemental peak shaving supplies are required on some of these days. Reduced gas consumption by existing customers during days with degree-day totals in these intervals may have a significant impact on the Company's long-term need for additional supplies to meet sendout requirements on a seasonal basis, especially as the reductions accumulate over a period of years.

The Council believes that Boston Gas can obtain sufficient data to produce a reliable forecast that accounts for conservation. The Company is metering a sample of its customers on a weekly basis and monitoring changes in annual consumption with its conservation data bases. We commend the Company for these efforts. The Company should be able to develop other sources of data in the future that will enable it to understand and predict changes in consumer behavior. Moreover, the Company's variable heating increment algorithm allows it to model reduced customer usage as a phenomenon that occurs on a yearly basis, but does not occur during extended periods of extreme cold. The Council recognizes the difficulties in producing a reliable forecast of conservation; nevertheless, the Company must make better use of available data in its forecast.

Therefore, we ORDER the Company to account for reduced consumption by existing customers in its next filing as shown by its meter-reading study, data base reports, and other data analyses or studies. The Company should state explicitly its source(s) of data for determining the reductions in consumption per customer and its judgements in interpreting the data. The Company should also describe in detail how forecasted reductions are allocated between the heating and non-heating seasons, between base load and temperature-sensitive load in each season, and between peak and off-peak degree-day intervals for temperature-sensitive load in each season. The Company should meet with Council Staff within ninety days to discuss compliance with this Condition, appended to this Decision as Condition 2.

3. Allocation of Load Growth by Customer Class

After it sets load growth targets and calculates base load and heating factors, Boston Gas determines the amount of load in each customer class that it intends to add to its system. First, the Company divides its temperature-sensitive load growth between new residential and commercial heating customers. It calculates the number of residential heating customers that it can add from the calculated amount of residential heating load growth (in MMCF) and its estimates of use

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29 Response to Data Request SR-9.

30 264 DD in the 0-20 DD interval and 2828 DD in the 20-40 DD interval. See Table 5, supra.

per customer (in MMCF per customer). Then, the Company determines base use by the new residential and commercial heating customers and subtracts the result from its base load growth targets. The remaining base load growth is designated for marketing to industrial and commercial non-heating customers. At each step, load allocations are cross-checked with marketing information to insure that the load growth targets for each class can be achieved.[31]

Table 6 summarizes the assumptions made by the Company during the allocation process, including the number of customers and the use per customer for the residential class, and load assumptions for the commercial and industrial classes. These assumptions are reviewed in the sections that follow.

TABLE 6

Load Growth Allocation Assumptions

A. Number of new residential customers

	1982/3-83/4	83/4-84/5	84/5-85/6	85/6-86/7	86/7-87/8
Conversion of non-heating customers	1500	1093	1098	1100	1150
New construction	250	150	150	150	150
Wakefield	100	100	100	100	100
Total	1850	1343	1350	1350	1400

B. Use per residential customer (Mcf per normal year).

	Base Load	Heating Load
Converted non-heating customers	33	105
(Lost to non-heating class)	(23)	(0)
New construction	30	110
Wakefield	10	110

C. Commercial and Industrial Load Growth (MMcf per normal year)

	1982/3-83/4	83/4-84/5	84/5-85/6	85/6-86/7	86/7-87/8
Commercial Heating Load	157	144	149	146	146
Commercial Base Load	220	85	87	86	86
Industrial Base Load	99	120	120	120	120

Source: Forecast, Tables G-2 and G-3C; Responses to Data Requests SR-3 and SR-10.

31 Response to Data Request SR-3; Forecast, S.1. at 28-37.

a. Residential Class

(i) Number of new customers

Boston Gas forecasts that "the primary market for residential gas heat conversions continues to be homeowners who currently use gas for non-heating purposes."[32] Though the Company acknowledges that its growth potential "has diminished in light of current and projected price relationships between gas and oil" and that "the possibility of a significant gas price increase relative to No. 2 oil in the post-1985 period could result in difficulty marketing supplies," it maintains that conversion rates will tend to stabilize at approximately 1200-1300 per year.[33] The Company's projections are based on "[r]esearch conducted on behalf of the Company by an independent contractor."[34] Boston Gas forecasts that some additions will come from new construction on lots with access to an existing gas main, and that new heating customers will be added by Wakefield Municipal Gas, for whom Boston Gas is the sole supplier.[35]

Though conversion demand has declined since 1980, conversion rates in the first six months of 1983 have leveled off at a rate compatible with the Company's forecast.[36] Estimates of new construction are modest for a company of Boston Gas's size. Boston Gas's estimates of load added by Wakefield exceed Wakefield's own estimates, but the differences are minor.[37] Moreover, the Company has demonstrated both its awareness of changing market conditions in the wake of gas decontrol, as well as its willingness to dedicate resources to monitor the changes. We therefore conclude that the Company has shown that its forecasted growth in the number of residential heating customers is achievable.

(ii) Use per customer

The Company's assumptions on use per customer, as shown in Table 6, have changed since its previous filing. The average use per converted heating customer per normal year has been reduced from 110 Mcf to 105 Mcf; the average base use per converted customer has been increased from 30 Mcf to 33 Mcf; the average base use per newly-connected customer has been reduced from 40 Mcf to 30 Mcf. These changes are based on information from heating engineers and plumber-installers, who estimate annual loads at the time of installation based on assessments of building size and heat loss.[38]

We note that the Company expects to complete a new appliance saturation survey by December, 1983.[39] Information from the survey can be used to update the Company's assumptions on base load and heating use per customer, as well as to increase its understanding of the potential

32 Forecast, S. 1, at 30.
33 Id, at 30, 29, and 25.
34 The EFSC Staff has examined this research, which was supplied by the Company as part of the Response to Data Request SR-15, and which is being held by the EFSC under Protective Order.
35 Forecast, s.1, at 29; See also Table G-3C.
36 Compare Table 6 with Response to Data Request SR-14.
37 See EFSC 83-2, In Re Wakefield Gas, 10 DOMSC ___, ___.
38 Response to Data Request SR-10 and SR-10A.
39 Response to Data Request SR-12.

for penetration into the residential market. We commend the Company for updating its information on appliance saturation, and we anxiously await the Company's usage of the data in its next filing.

b. Commercial/Industrial Classes

(i) Load growth

Boston Gas forecasts load growth in the commercial and industrial sectors by identifying specific end-uses and market sectors where there is potential for growth. In this forecast, the Company identifies growth opportunities in manufacturing process applications; commercial and institutional water-heat, cooking and clothes-drying applications; and new commercial office space applications that are more sensitive to space utilization and fuel storage problems than price.[40] These projections are based on market surveys, contact with developers, realtors and builders, and other marketing tools. The Company does not forecast the aggregate average use per commercial customer, because customer usage varies too greatly among customers for the statistic to be meaningful.

(ii) SIC coding

Boston Gas is currently in the process of applying SIC codes to its commercial and industrial accounts. In compliance with Condition 7 to the Council's last Decision, the Company uses SIC data to submit seperate forecasts for its commercial (SIC codes 0-19 and 40-97) and industrial (SIC codes 20-39) classes for the first time. Because approximately 20% of the Company's commercial/industrial accounts have yet to be coded, and because the Company's permanent system for monitoring SIC codes is not yet operational, the totals listed in the Forecast are based on estimates and extrapolation of available data.[41]

The Council believes that SIC coding is an important step for Boston Gas, because it will make new types of data available for monitoring customer reactions to changing market conditions. We recognize that the Company must overcome the obstacles of high commercial account turnover rates, lack of historical data, and the tremendous diversity of its commercial accounts. Though several individual SIC codes emerge as important, most of the commercial and industrial customers are spread among many SIC codes, often with large variations in use per customer within two-digit SIC code blocks.[42]

The Council is satisfied that the Company has made significant progress in its SIC coding efforts, and that it has complied with Condition 7 to our last Decision. We commend the Company for its

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40 Forecast, S.1., at 32-33.

41 Response to Data Request SR-16 and SR-18.

42 Response to Data Request SR-17. For example, the 1982/3 data show that 4077 apartments (Code 659) used 4650 MMcf; 3941 eating and drinking establishments (Code 58) used 1800 MMcf; but only three other code blocks used more than 500 MMcf, while more than forty code blocks contained over a hundred customers. The SIC code data must be aggregated to be useful, but the appropriate level of aggregation is not immediately clear.

efforts to date. We expect the Company to continue to forecast commercial and industrial consumption separately in all future filings, and to use disaggregated SIC code data to improve its forecasting methods for these classes.[43] We also expect the Company to identify the SIC codes of the market sectors where it sees potential for growth.

4. Overview of the Methodology

The Company's methodology as described to this point is quite different from the econometric and comprehensive end-use models used by other utilities. Boston Gas has also attempted to forecast sendout with econometric techniques, and is collecting data that might be useful for a comprehensive end-use model. This section reviews briefly the Company's attempts to forecast sendout using econometrics, compares the Company's current methodology to comprehensive end-use methodologies, and comments on the merits of each of the three approaches.

a. Econometric modeling

Econometric approaches to sendout forecasting establish numerical relationships between historical sendout data and explanatory variables taken from economic theory (e.g. price, income). Sendout in future years can be calculated by forecasting how the explanatory variables will behave in the future, and by assuming that the numerical relationships between the variables will continue to be valid. The reliability of an econometric forecast depends on the reliability of the forecasts of the explanatory variables, the stability of the numerical relationships between variables over time, the statistical strength of these relationships, and the strength of the economic theory on which the choice of explanatory variables is based.

Boston Gas used an econometric model (the so-called "Zinder model") to forecast firm sendout in its 1979 filing. The Council was critical of the Zinder model: we questioned the lack of historical data, the statistical insignificance of important variables, and the weakness of the model's basis in economic theory.[44] The Company subsequently returned to its previous approach for forecasting sendout.

Recently, the Company has made three more attempts to model its sendout with econometrics. The Zinder model was updated to include recent historical data and to modify the original numerical relationships. In a separate effort, disaggregated sales and revenue data from individual sales divisions were matched with available macroeconomic data from the major counties served by the Company. Finally, covariance analysis was used to relate sendout data to price, county income, and weather data.[45]

Generally, the Company found these attempts to be unsuccessful. Though the Zinder model was improved by adding of more data, the statistical strength of its numerical relationships and the consistency of the economic theory behind these relationships remained problematic. Likewise, the numerical relationships based on county data suffered from

43 See also In Re NEES, 7 DOMSC 270, 294-300 (1982).

44 4 DOMSC 50, 60 (1980). See also 9 DOMSC 1, 12-15 (1983).

45 Forecast, S.1, at 36; Response to Data Request SR-19.

the statistical insignificance of key variables (e.g., price) and values of specified coefficients that conflicted with theory (e.g., wrong sign on income). The covariance analysis was adequate for explaining historical trends in gas consumption per residential customer, but contained unreasonably large errors when used in an ex-post forecast of actual data.[46]

Thus, the Company concluded that the disadvantages of econometric methods for sendout forecasting outweigh the advantages, and did not use econometrics in its 1983 Forecast.

The Council appreciates the Company's efforts to date. We recognize that a major advantage of econometric methods, explicit treatment of price and income effects, is lost when the relationships between sendout and these economic variables cannot be specified reliably on the basis of available data. At this time, the value of further efforts to use econometrics to model aggregate sendout is uncertain, because of the importance of non-price variables that affect customer usage patterns but are difficult to quantify; changes in the historical relationships between sendout, weather and economic variables, including the distinction between long-term and short-term reactions to large price increases; and the importance of Company judgements in determining whether to add new customers.[47] Moreover, the Company's current approach can be used to model the changing temperature-sensitivity of its load, which might be more important than economic variables to predict daily sendout requirements for dispatching purposes.

This is not meant to rule out the use of econometrics to augment the current approach; for example, to forecast seasonal use per customer for existing residential heating customers, to relate use per customer within industrial two-digit SIC code divisions to regional or national macroeconomic indicators, or to test hypothesized relationships. Indeed, if sufficient data are available, econometric techniques can be useful to identify the forces that drive trends in consumer behavior. The Council encourages further efforts along these lines and requests that the Company keep us informed of its progress.

b. End-use modeling

End-use approaches use disaggregated data on gas consumption for each end-use (e.g., space-heating, water heating, cooking, clothes-drying, boiler fuel, process use) and the number of users (e.g., number of heating customers, number of gas water heaters, etc.) to determine consumption by end-use category and reaggregate over all categories to calculate total sendout. Sendout in future years can be forecasted by forecasting consumption per end-use and the number of users. The reliability of an end-use forecast depends on the reliability of the end-use data and assumptions, the ability to forecast how usage patterns changes over time, and the fit between the results of the end-use consumption model and actual sendout data.

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46 Forecast, S.1., at 37; Response to Data Request SR-19.

47 Response to Data Request SR-9; 1982 Forecast, Appendix B.

Boston Gas uses elements of end-use modeling to allocate load growth between customer classes. Though load growth targets are set on the basis of management decisions (IV. B.1., supra), the targets are matched with end-use assumptions on consumption and number of users for each customer class (IV. B. 3., supra). Data from the Company's appliance saturation survey, weekly meter-reading study, or SIC coding efforts might be used to check the reliability of these assumptions. The Council believes such efforts present an opportunity for the Company to improve its forecast of load growth, especially with respect to commercial/industrial growth within individual SIC divisions.

Boston Gas does not use end-use modeling to forecast the sendout requirements of its existing customers. Base load factors and heating increments are used to represent the aggregated requirements of all of Boston Gas's customers, with no provision for matching those requirements with end-use assumptions or for forecasting how usage patterns change over time (IV. B.2, supra).

Yet, Boston Gas's Forecast makes implicit assumptions about gas consumption rates within individual end-use categories. For example, it can be shown that the Company's calculation of base load factors assumes implicitly that the average base load consumption per existing residential customer is 29.1 Mcf per year.[48] With additional estimates and data, similar calculations might be done to identify the Company's implicit assumptions of base load consumption per heating or non-heating customer, or to estimate the end-use consequences of the Company's heating increment calculations.

The Council would have more confidence in the reliability of Boston Gas's Forecast if the end-use consequences of its usage of base load factors and heating increments were confirmed by reference to end-use data. End-use data might be useful to investigate the reasons for changes in customer usage patterns; to evaluate the reliability of conservation estimates; or to separate cyclic and permanent changes in consumption by commercial or industrial customers. Again, the Company's aforementioned SIC coding efforts, weekly meter-reading study, conservation data base reports, appliance saturation surveys and econometric modeling efforts should be helpful.

The Company recognizes that reliable data for end-use models are difficult and costly to obtain and dependent on weather conditions. Long-term planning may require data or modeling techniques that differ from what is useful for short-term dispatching purposes. We acknowledge the Company's efforts to date. Furthermore, we recognize that some of the data (e.g., SIC code data) will be of limited value until data has been collected for several years. Nevertheless, the Company is taking long-term steps to upgrade its forecast of the sendout requirements of

48 This assumes that annual base load consumption is the product of the daily base load factors and the number of days in each season, that residential customers account for 57% of base load sendout, and that the number of residential customers is the same as shown in Tables G-1 and G-2 of the Forecast. See also Response to Data Request SR-11.

its existing customers to the point where aggregate system data can be reconciled and cross-checked with end-use data. We will continue to monitor the Company's progress toward this goal.

C. Summary: Sendout Analysis

Boston Gas has submitted a thoroughly reviewable forecast of sendout requirements and has improved both its forecast methodology and the documentation that supports it. The Council appreciates the Company's efforts in producing the forecast, as well as its cooperation throughout the review process. The Company has several ongoing projects to collect data that might improve its forecasting; the Council applauds these efforts and looks forward to reviewing the results.

The Company has been ORDERED to comply with two Conditions in its next filing related to the treatment of conservation in its forecast of sendout. These Conditions are affixed hereto in Section VII, our Decision and Order, as Conditions Number 1 and 2.

V. RESOURCES AND FACILITIES

A. Sources of Gas Supply

This section reviews the judgements and decisions made by Boston Gas in projecting the availability of gas from its suppliers. Boston Gas is supplied with gas under the contracts listed in Table 7. The table also lists the amount available from each supplier on an annual basis, the method of transportation to the Company's service territory, and the starting and termination dates for each contract. For purposes of forecast review, the Company's supply contracts are divided into existing contracts (AGT F-1, WS-1, and SNG-1; TGP CD-6; Distrigas LNG) and future contracts (SIS, Boundary, and Trans-Niagara). We also address the role of conservation programs as a "source" of gas for the Company.

1. Existing Contracts

a. Tennessee Gas Pipeline (TGP) CD-6: Curtailment

Under its CD-6 service, TGP provides approximately one third of the gas that Boston Gas received under firm contracts. Boston Gas projects that "full annual volumes pipeline deliveries under the current CD-6 rate schedule will be available over the forecast period."[49]

Boston Gas bases its projection on information provided by TGP. TGP projects that gas deliveries to Boston Gas will be curtailed as shown in Table 8. TGP projects only minor curtailment during the heating season through 1988, though TGP projects significant curtailment during the non-heating season. On the other hand, these figures reflect minimum deliverability levels on a firm basis. Boston Gas states that it "anticipates that Tennessee will have excess deliverability capacity above its expected gas sales,"[50] and will be able to deliver gas at full AVL levels through the forecast period.

We note here that TGP's projections of curtailment volumes during the non-heating seasons of the forecast period are less than Boston Gas's forecasted levels of interruptible sales.[51] Were curtailment to occur at the levels projected by TGP, the Company could still meet its firm requirements in the manner forecast by reducing its sales to its interruptible customers. Yet, the Council is concerned about the long-term implications of curtailment beyond the forecast period and expects the Company to report on the situation in future Forecasts. This concern is discussed further in Section VI. A.3. infra.

b. Algonquin Gas Transmission (AGT) F-1 and WS-1: Curtailment and Contract Extension

AGT provides approximately half of the gas that Boston Gas receives under firm contracts. Boston Gas projects that AGT "can deliver...its full entitlement under all applicable rate schedules throughout the forecast period."[52]

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49 Forecast, S.1, at 8.
50 Response to Data Request S-1.
51 Compare Forecast, Table G-4(a). See also Table 16.
52 Forecast, S.1., at 4.

TABLE 7

Gas Supply Contracts

Contract	Supplier	MMCF/year	Transportation	Contract Dates
AGT F-1	AGT	34306	AGT pipeline	Through 10/88
WS-1	AGT	2748	AGT pipeline	Through 11/87
WS-1	AGT	146	AGT pipeline	Through 11/89
SNG-1	AGT	379	AGT Pipeline	Through 9/87
SIS	AGT, Consolidated	421[a]	AGT pipeline	9/83 to 3/86[d]
TGP CD-6	TGP	24308[b]	TGP pipeline	Through 11/2000
Distrigas LNG	Sonatrach	13746	Ship	Through 12/97
Boundary	TransCanada	2737[c]	NIPS, TGP pipelines	11/85 to 10/96[d]
Trans-Niagara	Pan-Alberta	3832[c]	NIPS, AGT pipelines	11/86 to 10/96[d]

Source: Forecast, Table G-24.

a The 421 MMcf refers to gas provided by Consolidated. Under the SIS contract, Boston Gas will also store 421 MMcf of AGT F-1 gas.
b Annual Volumetric Limitation (AVL). Full contract quantity is 35032 MMcf. Delivery limited to 24308 MMcf by FERC Order in Docket No. CP73-115.
c Gross supply at 100% including fuel losses.
d Subject to regulatory approval and construction of facilities.

TABLE 8

TGP Scheduled Deliveries and Curtailments, 1984-1994.

(MMCF)

Period	Scheduled Deliveries Heating	Scheduled Deliveries Non-heating	Total	Curtailment Heating	Curtailment Non-heating
11/84-10/85	13044	10767	23810	0	497
11/85-10/86	13038	10556	23594	6	708
11/86-10/87	13022	10162	23184	22	1102
11/87-10/88	13108	10088	23196	(64)	1176
11/88-10/89	13004	9840	22844	40	1424
11/89-10/90	12992	9584	22576	52	1680
11/90-10/91	12980	9339	22319	64	1925
11/91-10/92	12909	9058	21967	135	2206
11/92-10/93	12460	8794	21254	584	2470
11/93-10/94	11828	8556	20384	1216	2708
Full AVL	13044	11264	24308		

Source: Response to Date Request S-1. Assumes 1.022 MMBtu/Mcf.

Boston Gas bases its projection on an AGT forecast of deliveries through 1994. Unlike TGP, AGT projects that full deliveries will be made through 1994 under both the F-1 and the WS-1 rate schedules. In fact, the AGT projection extends well past the termination dates of the F-1 and WS-1 contracts. This supports Boston Gas's expectation that the WS-1 service will be extended at least through the forecast period.[53] In addition, Boston Gas projects sufficient excess deliverability capacity on the AGT system to allow purchases of 13207 MMcf of interruptible gas in 1983. No projections of interruptible purchases are made beyond the current year.[54]

c. <u>SNG-1: Volume Reductions</u>

In addition to WS-1 and F-1, AGT provides Boston Gas with Synthetic Natural Gas (SNG) under its SNG-1 rate schedule. The full contract calls for deliveries of 1844 MMcf per year.

In previous years, Boston Gas had negotiated with AGT to reduce its SNG-1 deliveries to approximately half of the full contract quantity because of its price. SNG-1 has been the most expensive source of gas to Boston Gas since 1973. For example, Boston Gas recently reported to the Department of Public Utilities that SNG-1 had a unit cost of $14.44 per Mcf, as compared to its system average cost of gas of $4.95 per Mcf.[55]

In the spring of 1983, Boston Gas[56] arranged to reduce its SNG-1 deliveries to 379 MMcf per year, which is 21% of the annual contract quantity. The SNG-1 will be delivered only during January at a rate of 12.2 MMcf per day. The reductions will continue until the contract ends in 1987. Boston Gas has indicated that it will only purchase SNG-1 after 1987 "if it provides an economic alternative to available supplies."[57]

The Council is pleased that Boston Gas has reduced its reliance on its highest-cost supply. The reduction in SNG-1 volumes will result in significant savings in gas cost for its customers. The SNG-1 supplies that remain under contract will be received during the height of the heating season when sendout requirements are greatest. Additional SNG-1 supplies will remain available on a best-efforts basis if required. The Council urges the Company to continue to renegotiate its contractual obligations for high-cost supplies in order to maximize supply availability and meet sendout requirements in a least-cost fashion.

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53 Response to Data Requests S-2 and S-4.

54 Response to Data Request S-3; <u>Forecast</u>, Table G-22.

55 Response to Data Request D-V: Cost-of-Gas-Adjustment Calculation, July, 1983.

56 Five other Massachusetts gas utilities reduced their SNG-1 takes in the same set of negotiations.

57 Response to Data Request S-5.

d. Distrigas LNG: Proposed Contract Amendments

Boston Gas contracts for 13,746 MMcf per year of liquefied natural gas (LNG) from the Distrigas of Massachusetts Corporation (DOMAC), an affiliate of Distrigas Corporation (Distrigas). Distrigas imports the LNG from the Algerian national oil and gas company, Sonatrach, which brings it by ship to the Boston harbor LNG terminal. At the terminal, Distrigas buys the gas from Sonatrach and sells it immediately to DOMAC. DOMAC then resells the gas to Boston Gas and other utilities from its LNG terminalling, storage, vaporization and truck-loading facilities in Everett, Massachusetts. By contract, 100% of the LNG that DOMAC sells to Boston Gas is sold on a take-or-pay basis.

In 1982, Distrigas renegotiated its LNG contract with Sonatrach. Distrigas and DOMAC then applied to ERA and FERC for approval of the contract amendments.[58] Neither FERC nor ERA has begun proceedings to consider approval of the amendments.

As part of the amended contract, Distrigas and Sonatrach agreed to change the LNG ship delivery schedule. Instead of 15 LNG shipments spread evenly over the year, the proposed agreement schedules 9 LNG shipments during the heating season and 5 LNG shipments during the non-heating season. LNG shipments would be more highly concentrated during the winter, when sendout requirements are highest.

The proposed schedule change raises the issue of the reliability record of Distrigas LNG shipments and the resulting impact on Boston Gas's supply planning. During the contract years 1976-1981, the Massachusetts Department of Public Utilities has found that Distrigas delivered only 60% of the contracted-for volumes of LNG.[59] Shipments were missed in January, 1979; June, July, August and September, 1980; and January, 1981.[59A] In the latter case, the missed shipment occurred during an extended period of extremely cold weather, thereby contributing to the "gas crisis" of 1981.[60] The record has improved in recent months. Distrigas delivered 100% of contract volumes between April, 1981, and March, 1983.[61] Yet, as recently as October, 1982, an LNG shipment was delayed because of technical difficulties.[62] Based on the historical record, the ability of DOMAC to deliver full contract quantities of LNG on time as scheduled should be viewed with caution.

Because of the reliability record, Boston Gas has set a policy of having available sufficient gas supply "to meet the needs of its customers in a design year in the event of a complete interruption of winter Distrigas deliveries."[63] Thus, Boston Gas has contracted for terminalling rights at the Dorchester Sea-3 propane facility in Newington, NH. Were Distrigas to miss an LNG shipment during the heating season, Boston Gas would purchase additional propane if required to meet firm load (See Section VI.C.2. and Table 21, infra).

Boston Gas would be forced to adjust its supply planning if the proposed changes in the LNG shipment schedule were approved. Given that

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58 FERC Docket No. CP-77-219-001; ERA Docket No. 82-13-LNG (See 47 Fed. Reg. 46812 (October 20, 1982).

59 DPU Docket No. 555-C, at 90.

59A See Boston Gas, 1982 Forecast, Appendix A.

60 DPU Docket No. 555-C, at 140-148.

61 Response to Data Request S-9.

62 9 DOMSC 1, 81 (1983).

63 Forecast, S. 1, at 11.

Boston Gas retains supplemental supplies sufficient to make up for the possibility of missed LNG shipments - if the amount of LNG scheduled to arrive during the winter were to increase, then Boston Gas would be forced to plan for a larger contingency. Contingency planning costs money. All other factors being equal, Boston Gas would have the choice of changing its supply planning to become more reliant on Distrigas LNG deliveries, or passing the costs of additional contingency planning on to its customers.[64]

There are at least three ways in which the existing contract might be amended so as to relieve Boston Gas of additional cost or risk. First, Boston Gas might obtain a reduction in its contractual quantities of LNG below 13746 MMcf. Second, Boston Gas might negotiate a reduction in the take-or-pay level of the contract below 100%. In either case, Boston Gas would have the amount of LNG that it is forced to take during the winter reduced. Alternatively, Distrigas (or Sonatrach) might assume greater contractual responsibility for the costs of missed or delayed LNG shipments, including the cost of contingency planning. The probability of a missed shipment might be reduced if the supplier was required to pay for its consequences. Further, the Company might bear less risk associated with contingencies outside of its control. Of course, other such contractual amendments might be devised to achieve this result.

In light of the difficulties imposed upon it, Boston Gas petitioned to intervene at FERC and ERA in opposition to the proposed schedule changes. It also opposed several of the other proposed contract amendments.[64A]

While awaiting ERA and FERC action, Boston Gas reached a negotiated settlement with DOMAC. The Company was able to obtain a partial solution of the first course suggested above; its annual contract quantities of LNG will be reduced from 13746 MMcf to 10336 MMcf over four years (see Table 9).[65] Concurrently, reductions are scheduled in its usage of DOMAC's LNG vaporization and liquid delivery facilities (see Sections V. B. 3 and V. C. 2, infra). Boston Gas retains an unsatisfied request with DOMAC to further reduce its annual contract quantities to 8400 MMcf. Boston Gas also continues to protest the manner in which DOMAC presented the agreement to FERC in its tariff filing.[65A]

Though the Council has previously recognized the problems associated with the reliability of Distrigas LNG, in the past the Council required the Company to take responsibility for insuring the reliability of its supplies through contingency planning. Thus, in its 1979 Decision, the Council ordered the Company to:

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64 DPU 555-C, at 140-148.

64A Forecast, S.1., at 9.

65 See 48 Fed. Reg. 26868 (June 10, 1983).

65A See 'Answer of Boston Gas Company Partially in Support and Partially in Protest of Abbreviated Application of Distrigas of Massachusetts Corporation' (June 20, 1983). FERC Docket No. CP77-216-009.

TABLE 9
Proposed Reductions in Annual Contract Quantities of DOMAC LNG

Effective Date	Reduced Annual Contract Quantity (MMCF)	LNG Vapor Deliveries (MMCF PER DAY)	Liquid Deliveries (MMCF PER DAY)
4-1-84	13,163	63.7	28.3
4-1-85	12,437	60.3	26.8
4-1-86	11,768	57.0	25.3
4-1-87	10,336	50.0	22.3
Pre-settlement	13,746	66.6	29.6
Requested	8,400	40.7	18.1
Unsatisfied	1,936		

Source: *Forecast*, S.1, at 10.

"... report to the Council in its next filing on its contingency plans to meet all projected load requirements in the event that the supply of Algerian LNG is no longer available..."[66]

In its 1981 Decision, the Council ordered the Company to "further develop and substantiate its "contingency plans".[67] In its 1982 Decision, the Council requested

"[t]hat the Company work with the Council staff to assess the regional impacts of a cessation of deliveries of Algerian LNG."[68]

The important point is that, historically, Boston Gas has borne a disproportionate share of the burden of insulating its firm customers from the risk of reliance on LNG shipments.

In view of the unresolved issues regarding tariffs and the recent DOE natural gas import policy guidelines (2/17/84), the contract amendment proceedings now before FERC and ERA provide an opportunity to further review the balance of cost and risk between Boston Gas and its LNG suppliers. In concert with the Council's mandate "to secure a supply of energy for the Commonwealth at minimum environmental impact and the least possible cost,"[69] we find that it is in the best interest of the Commonwealth's gas consumers for the Council and the gas distribution companies to vigorously pursue strategies that reduce their exposure to supply disruptions and their incurrence of contingency planning costs.

Moreover, such a review would be consistent with other trends in the natural gas industry. As gas decontrol has been gradually phased in, contracts have been renegotiated throughout the industry to reflect flexible contract terms and new market conditions. The terminalling contract with Sea-3, the CONTEAL project and the Canadian gas projects (see Section V.B.2., infra) show that the industry is responding with new supply projects that have the potential to compete with DOMAC LNG volumes for meeting sendout requirements under certain circumstances.

We recognize that Boston Gas is limited in its remedies by its contractual commitments. Moreover, the Company relies on stored LNG to meet its cold snap requirements, and DOMAC is currently the Company's sole supplier of LNG. Nevertheless, the Boston Gas - Distrigas contract, as amended by the settlement agreement, continues to contain provisions - e.g., 100% take or pay, contracted volumes above requested amounts - that are not consistent with current gas industry conditions. We recognize that these provisions are part of a negotiated settlement agreement, and that Boston Gas has withdrawn its opposition to the contract amendments, apart from the disputed tariff issues. We do not specifically order Boston Gas to seek to renegotiate the settlement agreement, consistent with the conditions set out below. It should be noted, that the settlement agreement, including associated tariff filings, has yet to be approved by the appropriate regulatory bodies. We herein impose a burden on Boston Gas in all future

66 4 DOMSC 1, 32 (1980).
67 7 DOMSC 1, 79 (1982).
68 9 DOMSC 1, 112 (1983).
69 M.G.L., Chapter 164, Section 69J.

negotiations to use all due diligence to seek remedies that will reasonably reduce its costs and risks, such as reductions in its take-or-pay obligations, further reductions in its total Distrigas LNG volumes, or pursuit of other contractual remedies that will reduce the Company's LNG associated costs and risks (see Condition 3). The Company is further ordered to document efforts in compliance with this Condition in its next Forecast.

2. New Contracts

a. AGT/Consolidated Storage Service (SIS): New Supply

Boston Gas has elected to participate in a three-year storage service offered jointly by AGT and Consolidated Natural Gas Service Company (Consolidated). Under the proposed agreement, Consolidated and AGT will each provide 421 MMcf of gas for injection into underground storage during the non-heating season. AGT will provide pipeline transportation to Boston on a firm and best-efforts basis (See V. C.1., *infra*).

The new SIS service is meant to "assist the Company in backing off quantities of more expensive SNG-1."[71] FERC approved the first year of service by letter order on August 30, 1983. Review of the last two years of the project is in process.

b. Canadian Gas: Boundary, Trans-Niagara, and Sable Island

Boston Gas is participating in two joint ventures to receive Canadian gas by pipeline; Boundary and Trans-Niagara. Both projects have undergone substantial changes since the Council's last review.

One major change is the amount of gas scheduled to be delivered. On January 27, 1983, the Canadian National Energy Board (NEB) authorized for export only half of the volumes originally requested by TransCanada and Pan-Alberta for sale to the Boundary and Trans-Niagara partners. Thus, Boston Gas now forecasts that it will receive 2737 MMcf annually from Boundary and 3832 MMcf annually from Trans-Niagara - volumes that have been reduced from its previous entitlements for each project.[72]

The transportation arrangements and projected on-line dates of both projects have also changed. In December, 1982, the Federal Energy Regulatory Commission (FERC) ordered the parties who will transport the Canadian gas to build a joint venture pipeline between Niagara Falls and their current pipeline systems, thereby avoiding construction of two parallel and adjacent pipelines (and reducing the environmental impact of the construction). The proposed pipeline, called the Niagara Interstate Pipeline System (NIPS), will carry Canadian gas for both projects. This change in the transportation arrangement is partially responsible for slippage in the projected on-line date of each project.[73] Boston Gas now projects that Boundary Gas will be available in November, 1985, and that Trans-Niagara gas will be available in November, 1986.

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71 Response to Data Request S-6.

72 NEB License No. G.L.-83.

73 Other contributing factors were the need to reallocate gas volumes after the NEB decision, and the lengthy nature of the FERC hearings on the Firm Initial Service phase. ERA approved the Boundary project in October, 1982. ERA has not yet approved the Trans-Niagara project.

A third major change is the emergence of a new pipeline gas project that uses gas from United States producers. In May, 1983, the Boundary consortium applied to FERC for approval to deliver Canadian Gas in two phases; a "Firm Initial Service (FIS)" phase delivering reduced volumes of gas to four companies (not including Boston Gas) by 1984; and a "Full Volumes" phase serving all customers upon completion of facilities on the TGP and NIPS pipelines. During the FERC hearings, three members of the Trans-Niagara consortium (CONsolidated, Texas Eastern, and ALgonquin) presented an alternative project called CONTEAL, using excess domestic gas supplies from Consolidated. In December, 1983, the parties to the CONTEAL and Boundary projects submitted a Settlement Agreement to FERC for approval of both the CONTEAL and the Firm Initial Service Boundary projects. Concurrently, they negotiated a second agreement for additional CONTEAL volumes for several Northeastern gas companies, including Boston Gas. The first Settlement Agreement is under consideration by FERC at this writing; proceedings concerning the second will begin shortly.[74]

As it stands, the negotiated settlement agreement will enable Boston Gas to purchase 9398 MMcf of gas per year from CONTEAL starting in 1986. Although prices and contract terms are subject to FERC approval, the price is projected to be competitive with No.6 oil.[75]

Having observed how the Canadian gas projects have changed over the previous year, the Council notes that further changes in the volumes, prices and delivery schedules may be ahead. Specifically, the Council is concerned that the Boundary volumes included in the forecast may not be available in 1985. These concerns are addressed further in Section VI.D.1., infra.

We also note that Canadian Gas might be made available to the Company from new wells being drilled near Sable Island off the coast of Nova Scotia. Boston Gas does not anticipate gas deliveries from Sable Island until 1990 or later, though it is still too early to forecast the price, schedule, or deliverability levels of this gas with any level of confidence.[76] Nevertheless, the Sable Island project does represent a potential long-term addition to the Company's gas supplies.

3. Conservation Programs

The Council evaluates conservation programs as a "supply source" on the same basis as the Company's other supply sources.[77] We consider the role of conservation programs in providing a necessary gas supply with a

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74 FERC Docket No. CP81-107-000 et al.

75 Prices are projected in the range of \$4.00 - \$5.50 per MMcf.

76 Response to Data Request S-8.

77 Here we make a distinction between "conservation", in the form of Company observations of reductions in consumption per customer related to increases in end-use efficiency, and "conservation programs", which are deliberate actions taken by the Company to meet requirements that would otherwise be met by conventional supply sources. See IV.B.2.c., supra.

minimum impact on the environment at the lowest possible cost.[78] To conduct a full review, we must evaluate their importance for meeting normal year, design year and peak requirements, as well as their reliability for meeting requirements during cold snaps.

Boston Gas is implementing several conservation programs, including two that are funded out of revenues derived from the Louisiana First Use Tax decision. The Company has completed a residential conservation pilot program that uses six community-based agencies to deliver a variety of conservation services to its customers. A second program, designed to facilitate financing of audit-recommended measures for non-profit social service agencies with gas heat, is in progress. In addition, the Company participates in Mass-Save; distributes printed conservation material to its customers; makes water heater insulation and vent dampers available through its service department;[79] and requires residential conversion customers to have efficient gas burners and to implement conservation measures before they can be added to the Company's distribution system.[80]

The Council encourages and applauds these efforts. We recognize the minimal environment impact of conservation as compared to other supply sources that require new construction. Conservation programs add diversity to the Company's supply mix, and reduce its dependence on imported sources of energy. Moreover, Boston Gas's innovative policy of mandatory conservation standards for conversion customers will help the Company to ensure that its supplies are being used efficiently.

On the other hand, the Council remains concerned with the value of conservation programs as a supply source on peak days and during cold snaps. The Company presents evidence that usage-per-customer increases disproportionately as the outside temperature falls.[81] However, there is no evidence as to how individual conservation programs, measures or strategies affect peak demand. For example, we cannot determine whether physical gains in end-use efficiency are offset by changes in customer behavior, or whether conservation programs have indeed made needle-peaks on cold days less severe than they otherwise would have been. We simply do not have enough information on the record in order to fully evaluate the reliability of conservation programs as a supply source.

Therefore, we urge the Company to obtain more information on the role of conservation programs in meeting its peak day and cold snap requirements. We request that the Company address this issue as it evaluates its conservation programs and as it collects data on customer behavior.

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78 M.G.L., Ch. 164, Sec. 69H.

79 Response to Data Request SR-22.

80 _Forecast_, S.1., at 29.

81 _1982 Forecast_, Appendix B.

B. Gas Sendout Facilities

This section reviews the facilities that are available to Boston Gas for sendout on a daily basis. Gas sendout facilities include citygates for receiving gas from the AGT and TGP pipelines; LNG vaporization facilities; liquid propane-air (LPA) production facilities; and a Synthetic Natural Gas (SNG) production plant. Boston Gas's facilities serve an area that is divided into nine operating divisions, eight of which are physically isolated from each other except for the TGP and AGT pipelines. Table 10 lists the nine divisions and the firm daily sendout capacity of the facilities that serve each division.

The Council's 1982 Boston Gas Decision addressed in detail the use of sendout facilities in each division, as well as the flexibility to move gas between division. That discussion will not be repeated. Instead, we discuss the changes in sendout capacity that have occurred since the Council's last Decision. We also discuss information on usage of the facilities that is newly available to the Council.

1. Citygate capacity

The changes in Boston Gas's citygate maximum daily quantities (MDQ's) correspond to the changes in its availability of pipeline gas supplies. When Boston Gas reduced its annual contract quantities of SNG-1, it also reduced its MDQ on the AGT pipeline by 12.2 MMcf per day (with the exception of the month of January, 1983-87; see V.A.1.c., supra). Table 11 shows that the MDQ reductions are split between the Boston and Norwood service territories. The table also shows the increased MDQ's associated with the Boundary and Trans-Niagara projects (see IV.A.2.b, supra). These Canadian projects will increase Boston Gas's MDQ's by 9.9 MMcf per day on the TGP pipeline and 7.0 MMcf per day on the AGT pipeline. The increase in MDQ's from the two Canadian projects exceeds the decrease in MDQ from the new SNG-1 agreement by 4.7 MMcf per day.

The MDQ increases associated with the Canadian gas projects will increase the flexibility of Boston Gas's system. For both projects, the sum of the increased MDQ's at individual citygates exceeds the system total. Boston Gas will be able to take Canadian gas in four different divisions on the TGP pipeline, and at Norwood or Boston on the AGT pipeline, thereby using the interstate pipelines to allocate gas between its non-contiguous divisions. The Council commends the Company for improving its system flexibility through its gas contracts in this way.

2. Backup supplemental facilities

Boston Gas has excess sendout capacity which is not included in Table 10. The excess capacity is used "to insure peak day coverage and to provide for the contingency of equipment malfunction."[82] These "backup" facilities include a 15 MMcf per day LNG vaporizer at Salem, a 62.5 MMcf per day LNG vaporizer at Dorchester, a 28.8 MMcf per day vaporizer at Lynn, and a 40 MMcf per day LPA production facility at Everett. In all, the Company has 146.30 MMcf per day of backup sendout capacity available if needed.

82 Forecast, S.1., at 16.

TABLE 10

Gas Sendout Facilities by Division - 1983/84
Maximum Daily Quantites in MMcf per day

Division	TGP	AGT[a]	LPA	LNG	SNG	Total
Boston	0	266.8	15.3[b]	191.6[c]	40	513.7
Norwood	0	8.7	5.4	0	0	14.1
Mystic/Lynn	74.2	0	11.6	57.6	0	143.4
North Shore	17.3	0	23.1	15.0	0	55.4
Gloucester	4.9	0	3.9	0	0	8.8
Leominster	7.8	0	4.0	2.4	0	14.2
Spencer	3.8	0	3.6	0.5	0	7.9
Southbridge	7.0	0	6.0	2.4	0	15.4
Clinton	2.8	0	0	0	0	2.8
System	96.0[d]	217.2[d]	72.9	269.5	40	695.6

Sources: Forecast, Tables G-14, G-23; EFSC 82-25, Information and Document Request No. 2, Copies of all contracts.

a Includes F-1, WS-1, STB and SNG-1 contract MDQ's.
b Does not include 40 MMcf/day capacity LPA plant used as a backup to the SNG plant.
c Includes 66.6 MMcf/day LNG vaporization from Distrigas.
d Maximum allowable coincident daily load on all citygates.

TABLE 11

Changes in Citygate Capacity by Division
Maximum Daily Quantities in MMcf per day

Division	1982 Capacity	Without SNG-1	With Boundary	With Trans-Niagara
Boston	266.8	(10.2)		+6.0
Norwood	8.7	(2.0)		+1.5
Mystic/Lynn	74.2		+21.08[a]	
North Shore	17.3		+ 7.70	
Gloucester	4.9		+ 1.00	
Leominster	7.8		+ 1.00	
Spencer	3.8			
Southbridge	7.0			
Clinton	2.8			
Sum	353.30	(12.2)	+30.78	+7.5
System	313.20	(12.2)	+ 9.9	+7.0

Source: Response to Data Request S-7.

a The sum of the increases at six different citygates within the division.

Boston Gas also has two portable ambient temperature LNG vaporizers, each with a rated capacity of 0.6 MMcf per day. The portable vaporizers can provide LNG at fifteen locations within the Company's service territory - seven in the Boston division, two each in the Leominster and Southbridge divisions, and one each in the Clinton, Gloucester, Norwood and Spencer divisions. The Company estimates that it can activate the portable units within four hours. These portable units provide the Company with an extra measure of flexibility.[83]

3. DOMAC Facilities

As part of its negotiated settlement to reduce its annual contract quantities of LNG (see V.A.1.d, supra), Boston Gas agreed to reduce its rights to use DOMAC's LNG facilities. If the settlement is approved as written, Boston Gas will reduce its right to firm LNG vaporization capacity from 66.6 MMcf per day to 50.0 MMcf per day, and will reduce its rights to deliveries of LNG in liquid form from 29.6 MMcf per day to 22.3 MMcf per day (see Table 9, supra). If Boston Gas is granted its full requested reduction in LNG contract quantities, its vaporization rights will be further reduced to 40.7 MMcf per day, and its liquid delivery rights to 18.1 MMcf per day. Reductions in DOMAC vaporization rights will reduce firm daily sendout capacity in the Company's Boston division, because the DOMAC facility is physically located within that division. Reductions in DOMAC liquid delivery rights will reduce Boston Gas's ability to bring LNG by truck to its LNG facilities in the Boston, Mystic/Lynn, North Shore, Leominster, Southbridge, and Spencer divisions, and to its portable LNG vaporizers.

Boston Gas will continue to use DOMAC facilities above its firm entitlements on a best-efforts basis. The Company can require delivery of up to 45 MMcf per day of vaporized LNG to the extent DOMAC has vaporization capacity available. The proposed settlement will not change this arrangement. Spare capacity would seem to be readily available, because only 152.1 MMcf per day of DOMAC's rated vaporization capacity of 285.0 MMcf per day is assigned to its firm customers.[84] Recently, Boston Gas used 131.6 MMcf per day of DOMAC vaporization on a 58 degree-day in January, 1983 - 20 MMcf more than its entitlement of firm and best-efforts capacity.[85] Further, the Company has stated that

> "Since the expansion of DOMAC's metering and vaporization capacity to current levels, the Company cannot identify any occasion when its total request for vaporization has been curtailed or denied during the heating season."[86]

Boston Gas also uses DOMAC facilities to provide transportation of DOMAC LNG to seven other gas companies by displacement. A typical displacement arrangement works as follows: Boston Gas takes the other company's entitlement of LNG from the DOMAC facility. Simultaneously, Boston Gas reduces its take of pipeline gas by an equal amount while

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83 Response to Data Request S-12.
84 Response to Data Request S-10.
85 Response to Data Request D-IV.
86 Response to Data Request S-10.

the other company increases its take of pipeline gas by that amount. Though LNG physically goes into Boston Gas's system and pipeline gas physically enters the other company's system, the records show just the opposite. Boston Gas has ongoing displacement contracts with DOMAC and the gas companies and pipelines listed in Table 12.

TABLE 12

Displacement Agreements

Company	Daily Quantity (MCF/D)	Pipelines
Brooklyn Union	20000	TGP
	30000	AGT, Tetco, Transco
Bay State	5000	TGP
Connecticut Light and Power	3500	TGP
	2000	AGT
South Jersey	3500	AGT, Tetco, Transco
Providence	2000	AGT
Essex County	1300	TGP
Berkshire	1190	TGP
Valley	440	TGP

Source: EFSC 83-25, Response to Data Request S-III, copies of contracts; EFSC 83-25, Letter of December 13, 1983.

4. Spencer Propane Facility

In its 1982 Decision, the Council approved the Company's proposal to build a 3.6 MMcf per day propane-air facility in its Spencer division. Concerned about the potential for pressure problems during a design heating season, the Council ordered the Company "to 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."[87]

The Company was able to meet the sendout requirements of its customers in the Spencer division during the 1982-83 heating season with existing facilities. The Company projects that the new facility will be in service by November, 1983, the start of the next heating season.[88] With the new facility in place, the Council finds no further need for extraordinary monitoring of sendout in the Spencer division. Therefore, the Council finds that the Company has satisfied Condition 10 of our previous Decision and Order.

87 9 DOMSC 1, 110, 112 (1983).
88 Forecast, Table G-16.

C. Gas Storage Capacity

Boston Gas injects gas into underground storage fields in New York and Pennsylvania during the summer for delivery during the winter. The Company also stores LNG and propane in tanks located in and around its service territory to hold supplies until they are needed to meet sendout requirements. Table 13 lists the storage capacity, transportation arrangements and locations of the Company's underground, LNG and propane storage facilities.

Two of the Company's storage arrangements have changed in the last year; Providence LNG, and AGT underground. This section describes the changes. It also evaluates the best-efforts transportation services provided by the TGP pipeline.

1. Providence LNG

As part of its negotiated settlement to reduce its annual DOMAC LNG quantities (see V.A.1.d., *supra*), Boston Gas agreed to make 25% of its storage in the AGT Providence LNG tank available to Connecticut Power and Light. If the settlement is approved as written, Boston Gas will reduce its right to LNG storage in Providence from 480 MMcf to 360 MMcf as of April 1, 1984.[89] The Company's total LNG storage capacity will decrease from 5263 MMcf to 5143 MMcf.

The Council notes that the proposed decrease in LNG storage at Providence is only a 2% decrease in the Company's LNG storage capacity. The Providence LNG facility is located outside of Boston Gas's service territory. All transportation of gas to and from Providence is by truck, because the Company has not entered into any displacement arrangements for gas stored at the facility. Moreover, if DOMAC deliveries cease for 120 days, the Company may call back its storage entitlement.[91] The Council is therefore satisfied that the Company has not diminished substantially the flexibility of its sendout capability through the release of 120 MMcf of storage capacity in Providence.

2. AGT/Consolidated Storage Service (SIS): Transportation

Boston Gas has elected to participate in a three-year underground storage service with transportation services provided by the AGT pipeline. See Section V.A.1.a., *supra*.

Transportation of the SIS gas will be on a firm basis up to MDQ, and on a best-efforts above MDQ. Specifically, on days when Boston Gas takes its full entitlement of F-1, WS-1 and STB transportation, the SIS gas will be available only if AGT allocates spare pipeline capacity for delivery. On days when Boston Gas takes less than its full entitlement of F-1, WS-1 and STB transportation, the SIS gas will be available on a firm basis up to the full entitlement.[92] Boston Gas will not receive additional peak capacity, but will have more gas available for firm delivery within present capacity levels.

89 *Forecast*, S.1., p. 17; Response to Data Request S-15.
90 Response to Data Request S-11.
91 *Forecast*, S.1., p. 17.
92 Response to Data Request S-5.

TABLE 13

Gas Storage Facilities

A. Underground Storage

Contract	Net MMcf/year	Transportation	Contract Dates
AGT STB	3272	AGT pipeline	Through 4/2000
AGT/Consolidated	800	AGT pipeline	Through 3/1986
Penn-York	896	TGP pipeline	Through 3/1995
Honeoye	818	TGP pipeline	Through 3/1994
Consolidated	105	TGP pipeline	Through 4/2000
	5891		

B. LNG Storage

Location (Owner)	Division	Capacity (MMcf)	Transportation	Associated Liquefaction MMcf/Day
Salem (Mass. LNG)	North Shore	1000	In service area	0.00
Lynn (Mass. LNG)	Mystic/Lynn	1000	In service area	7.35
Dorchester (Boston Gas)	Boston	2140	In service area	6.00
Everett (DOMAC)	Boston	643	Truck/displacement	0.00
Providence (AGT)	N/a	480[a]	Truck	0.00
		5263		

C. Propane Storage

Location (Owner)	Division	Capacity (MMcf)
Everett, West Concord, Braintree (Boston Gas)	Boston	86.3
Reading, Revere (Boston Gas)	Mystic/Lynn	29.6
Norwood (Boston Gas)	Norwood	14.9
Southbridge (Boston Gas)	Southbridge	14.9
Danvers (Boston Gas)	North Shore	12.2
Gloucester (Boston Gas)	Gloucester	9.7
Leominster (Boston Gas)	Leominster	9.9
Spencer (Boston Gas)	Spencer	1.6
Newington, N.H. (Sea-3)	N/a	361.0[b]
		540.1

Source: *Forecast*, Tables G-14 and G-24: Response to Data Requests S-11, S-15, S-17, S-18.

a Reduced to 360 as of April, 1984, subject to FERC approval.

b Amount of propane owned by Boston Gas in storage at Newington. Assumes 4,440,369 gallons at 12.3 per Mcf at Newington, and 179.1 MMcf of propane in storage within the Company's service territory. See Boston Gas, Response to Administrative Bulletin AB 82-1, dated November 17, 1983.

3. TGP Transportation of Underground Storage

TGP provides best-efforts transportation to Boston Gas for gas from three storage services; Honeoye, Consolidated and Penn-York. Total storage capacity under these three services is 1818 MMcf.[93] Because transportation is not guaranteed, the availability of this storage gas must be viewed with caution. The Company receives less storage return than it requests for a variety of reasons.[94] Table 14 shows the volumes of storage gas with TGP best-efforts transportation that Boston Gas forecasts it will receive in each normal heating season over the forecast period.

TABLE 14
TGP Best-efforts Storage Return
Normal Heating Season
(MMCF)

1983-4	72
1984-5	109
1985-6	102
1986-7	113
1987-8	163

Source: Forecast, Table G-22.

The Council notes that Boston Gas actually received 1253 MMcf of storage gas using TGP best-efforts transportation service during the 1982-3 heating season, and 1243 MMcf during the 1981-2 heating season.[95] In each case, over 75% of the seasonal total was taken in December, January and February. TGP authorized Boston Gas to take its full request of best-efforts gas on approximately 60% of the days in the last two heating seasons.[96] If the past record is an indicator of future performance, Boston Gas can reasonably expect to receive best-efforts storage return volumes at some point during the heating season in excess of the modest amounts that have been forecast. The role of best-efforts storage return volumes is discussed further in section VI.A.3., infra.

93 Forecast, Table G-22.
94 Response to Data Request S-14 and S-18.
95 Response to Data Request D-IV.
96 Response to Data Request S-14.

VI. COMPARISON OF RESOURCES AND REQUIREMENTS

This section compares the Company's resources, as reviewed in section V, supra., with its forecast of sendout requirements, as reviewed in section IV, supra. We examine whether the Company's gas supplies are sufficient to meet normal and design sendout requirements, and whether the Company's sendout capacity and storage arrangements are sufficient to meet peak day and cold snap requirements. We also examine how changes in forecast assumptions, including the availability of DOMAC LNG, and the timing of Boundary gas, affect the Company's ability to meet its requirements.

A. Adequacy of Gas Supplies

1. Normal Year

Boston Gas must have adequate supplies to meet four types of requirements in a normal year. First and foremost, it must meet the sendout requirements of its firm customers. It must insure that its underground storage facilities are filled to capacity prior to the start of each heating season. It must refill its LNG storage year-round as required to meet daily sendout fluctuations and to allow Distrigas LNG ships to be unloaded as they arrive. Lastly, it must account for the losses that are incurred during the injection, transportation, or withdrawal of stored gas. Tables 15 and 16 enumerate the Company's forecast of these requirements and the supply sources that it anticipates will be used to meet them for each non-heating and heating season over the forecast period. The tables also show the Company's forecast of interruptible sendout under normal weather conditions.

Several features in the tables are worthy of note. Reduced deliveries of DOMAC LNG (See Table 9, supra.) are scheduled to begin by the 1984 non-heating season. Deliveries of DOMAC LNG to meet sendout requirements and maintain LNG storage levels are forecast to decline from 6944 MMcf for the 1983/84 heating season to 5535 MMcf for the 1987/88 heating season. Boundary Gas from Canada is anticipated by the 1985 winter; Trans-Niagara by the 1986 winter. About 75% of the full contractual volumes under each Canadian gas contract is scheduled to be taken in a normal year. Though normal firm sendout grows steadily over the forecast period, the Company's total requirements fluctuate because of variations in the need and timing of storage refill requirements and in the forecast of interruptible sales.[97]

On the basis of the record as shown in Tables 15 and 16, the Council concludes that the Company's supply plan is sufficient to meet normal sendout requirements based on the Company's assumptions on supply availability and sendout requirements as stated herein.

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97 Forecast, S.1, p. 20. The resources listed in Tables 15 and 16 can be reconciled with the annual contract quantities listed in Tables 7 and 9 by adding the heating season takes to the corresponding non-heating season takes. For example, for CD-6 gas, adding 13590 for 1983-84 to 10718 for 1984 yields 24308 for the 1983-84 split year, which is the CD-6 AVL. This procedure does not work when the Company takes less than its full annual contract quantity in a normal year (e.g., Boundary), or when the contract year does not coincide with the Council's split year (e.g., F-1).

TABLE 15

Comparison of Resources and Requirements
Normal Year - Non-heating Season

REQUIREMENTS	1983	1984	1985	1986	1987
Normal Firm Sendout	21685	21820	21955	22090	22225
Fuel Reimbursement	9	23	36	2	3
Underground Storage Refill	4975	3595	3680	2898	2875
LNG Storage Refill	751	1722	2012	1893	1933
Interruptible Sendout	20283	4305	5912	7371	6907
TOTAL REQUIREMENTS	47703	31465	33595	34254	33943
RESOURCES					
AGT F-1	15499	12756	15518	15562	15561
WS-1	342	293	167	487	331
ST-1	75	467	477	0	0
Trans-Niagara	0	0	0	0	875
SUBTOTAL	15916	13516	16162	16049	16767
TGP CD-6	10912	10718	10623	10811	10847
Storage	103	47	85	59	51
Boundary	0	0	0	1180	1180
SUBTOTAL	11015	10765	10708	12050	12078
DOMAC LNG	6802	6462	6012	5853	4801
LNG from storage	342	301	292	302	297
SUBTOTAL	7144	6763	6304	6155	5098
Consolidated	421	421	421	0	0
I-1/I-2	13207	0	0	0	0
SUBTOTAL	13628	421	421	0	0
TOTAL RESOURCES	47703	31465	33595	34254	33943

Source: Forecast, Table G-1A, G-5, G-22; Responses to Data Requests S-15 and S-18.

TABLE 16

Comparison of Resources and Requirements
Normal Year - Heating Season

REQUIREMENTS	1983-4	1984-5	1985-6	1986-7	1987-8
Normal Firm Sendout	44953	45358	45771	46180	46589
Fuel Reimbursement	218	227	261	219	244
LNG Storage Refill	1602	1946	1867	1867	2344
Interruptible Sendout[a]	1741	1538	2210	1682	1487
TOTAL REQUIREMENTS	48514	49069	50109	49948	50644
RESOURCES					
AGT F-1	18769	18786	18786	18786	18785
WS-1	2601	2727	2407	2563	2809
SNG-1	379	379	379	379	0
ST-1	2167	2167	2737	2711	2906
AGT/Cons.	842	842	842	0	0
Trans-Niagara	0	0	0	1041	1041
SUBTOTAL	24758	24901	25151	25480	25920
TGP CD-6	13590	13685	13497	13461	13584
Storage	72	109	102	113	163
Boundary	0	0	1475	1475	1475
SUBTOTAL	13662	13794	15074	15049	15222
Propane-air	7	7	1	1	12
DOMAC LNG	6944	6701	6425	5915	5535
LNG from Storage	3143	3666	3458	3503	4354
SUBTOTAL	10094	10374	9884	9419	9901
TOTAL RESOURCES	48514	49069	50109	49948	50644

Source: *Forecast*, Table G-22: Response to Data Requests S-15 and S-18.

a Includes sales of gas to Colonial Gas Company on a best-efforts basis.

2. Design Year

During a design year, Boston Gas must have sufficient gas supplies to meet the additional sendout requirements of its temperature-sensitive customers. If the Company meets these requirements by sending out extra gas from storage, it must have sufficient supplies to refill its storage to capacity before the onset of the next heating season. Tables 17 and 18 list the Company's extra supply requirements for a design year. They also describe the sources of supply that the Company can use to meet these extra requirements.

The Company has a variety of options for meeting design year requirements. It can take more gas from LNG or underground storage than would normally be required. It can purchase special supplies of propane or LNG. It can send gas to firm customers that in normal years is sold to interruptibles. After 1985, it will be able to take Canadian gas supplies above its normal take levels. Alternatively, it can request AGT to increase its deliveries of SNG-1.

The actual choice of resources to meet sendout requirements on any particular day during a design year is determined by the Company's daily dispatching decisions, sendout facilities, contractual constraints, and the need to maintain storage inventories to meet cold snap requirements. The Company makes its dispatching decisions with the aid of its ABCGAS computer model.[98]

The actual choice of resources is also limited by other factors. Transportation of underground storage gas on the TGP pipeline (and above MDQ on the AGT pipeline) is not firm, but best-efforts; the Company cannot depend on being able to use this gas during peak periods. Extra supplies of propane and SNG-1 depend on the availability of supplies on the spot market. On warm days during a design winter, when daily sendout requirements fall below the Company's daily entitlement of pipeline gas, the excess pipeline supplies cannot always be stored for later use.

Nevertheless, the Company retains sufficient quantities of supplies above its normal needs, and sufficient diversity in its supply options, to meet its requirements during a design year. During the 1983/4 heating season, more gas is available from firm LNG, AGT and propane storage alone than is forecast to be required above normal sendout levels. In later years, the Company must dig deeper into its storage inventories, and must begin to rely either on timely dispatching decisions or on deliveries of TGP storage, DOMAC LNG or spot propane supplies (VI.C.2., infra). Though Table 17 shows an apparent shortfall for the 1984 design non-heating season, the Company should have enough time during that summer to obtain supplies for refilling its underground storage if required.

The Council therefore concludes that the Company's supply plan is sufficient to meet design sendout requirements subject to the accuracy of the Company's assumptions on supply availability and sendout requirements as stated herein.

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98 Forecast, S.1., at 21.

Table 17

Comparison of Resources and Requirements
Design Year - Non-heating Season

REQUIREMENTS	1984	1985	1986	1987
Design Firm Sendout	22566	22701	22836	22971
Normal Firm Sendout(-)	21820	21955	22090	22225
Excess of Design over Normal	746	746	746	746
Maximum Additional Storage Refill[a]	3717	3754	3785	3820
TOTAL ADDITIONAL DESIGN REQUIREMENTS	4463	4500	4531	4566
RESOURCES				
Interruptible Sendout	4305	5912	7371	6907
Canadian Gas above normal				
Boundary	0	0	948	948
Trans-Niagara	0	0	0	650
TOTAL ADDITIONAL DESIGN RESOURCES	4305	5912	8319	8505

Spot supply sources: SNG-1, propane, interruptible pipeline gas, extra DOMAC LNG.

Source: Forecast, Table G-22.

a Assumes underground and LNG storage facilities are emptied to meet design heating season requirements. Actual storage refill requirements are likely to be lower, because the Company can meet design needs with supplies other than those in storage.

TABLE 18

Comparison of Resources and Requirements
Design Year - Heating Season

REQUIREMENTS	1983/84	1985/85	1985/86	1986-87	1987/88
Design Firm Sendout	48670	49112	49556	50000	50441
Normal Firm Sendout	44953	45358	45771	46180	46589
Excess of Design over Normal	3717	3754	3785	3820	3852
RESOURCES					
Storage					
AGT Underground	1246	1246	713	738	555
TGP Underground	1673	1638	1645	1634	1586
LNG From Storage	2078	1447	1651	1607	773
SUBTOTAL	4997	4331	4009	3979	2914
Propane-air	533	526	525	524	512
Interruptible sendout	1741	1538	2210	1682	1487
SUBTOTAL	2274	2064	2735	2206	1999
DOMAC Storage refill	1602	1946	1867	1867	2344
Canadian Gas above normal take					
Boundary	0	0	26	26	26
Trans-Niagara	0	0	0	34	34
SUBTOTAL	0	0	26	60	60
TOTAL RESOURCES	8873	8341	8637	8112	7317
FIRM STORAGE (LNG, AGT and propane)	3857	3219	2889	2869	1840

Sources: *Forecast*, Table G-22: Responses to Data Requests S-14, S-17 and S-18; Response to EFSC Administrative Bulletin 82-1.

B. Adequacy of Gas Sendout Facilities: Peak Day

Boston Gas must have adequate sendout capacity to meet the requirements of its firm customers on a peak day. The Company must be able to meet its requirements within each of its nine sendout divisions, as well as on a system-wide basis.

Table 19 shows the Company's peak day capacity and its forecast of system-wide peak day sendout as filed in Table G-24 of the Forecast. Though the table seems to indicate that the Company has sufficient capacity, the data are subject to qualification. The 12.2 MMcf per day of capacity provided under the SNG-1 service will only be available during the month of January (see Section V.A.1.C., supra). The 59.9 MMCF per day of LNG vaporization capacity provided by DOMAC in 1987-88 includes 9.9 MMcf per day of capacity that is available on a best-efforts basis (See Section V.B.3., supra). The table projects sendout capacity associated with the forthcoming Boundary and Trans-Niagara projects (section V. B.1, supra), but omits the Company's backup and portable LNG facilities (Section V.B.2, supra).

Table 20, which disaggregates peak day capacity by division, gives a more complete view of the Company's ability to meet peak sendout requirements. In addition to the capacity listed in Table 19, Boston Gas can use its backup LPA production plants, its backup LNG vaporizers, or its portable LNG units to meet peaks. The Company retains flexibility in its dispatching, because it is able to direct pipeline gas to a variety of citygates in its divisions; to choose when to use the interconnection between its two largest divisions;[99] and to control usage of the backup and portable facilities to meet its needs most efficiently.

The table also gives Boston Gas's estimates of peak day sendout by division based on actual 1981-82 base load and heating increment data and a peak day of 73 degree-days. By providing these estimates, the Company has satisfied Condition 6 of the Council's previous Decision and Order.

We note that if backup capacity is considered, system-wide peak day capacity exceeds system-wide peak requirements by a wide margin. This holds true even without 12.2 MMcf per day of SNG-1 capacity and without the 16.6 MMcf per day of firm DOMAC LNG capacity proposed for reallocation. The capacity margin is also sufficient to account for system-wide increases in peak day demand to 693.6 MMcf per day by 1987-8.

Furthermore, sendout capacity is adequate within each division. Because of the interconnection, capacity in the Boston/Norwood division helps to meet demand in the Mystic/Lynn division. The capacity margin is smallest in the Clinton division, where use of a portable LNG vaporizer is required to meet requirements. Yet, Boston Gas retains flexibility for meeting peak sendout in Clinton. The Clinton citygate take station is located on the same lateral of the TGP pipeline as the Leominster take station. If required, TGP might be able to provide deliveries of a portion of Leominster's pipeline gas MDQ to Clinton, and Leominster could produce extra LPA to make up for the transfer.[100]

99 9 DOMSC 1, 71 (1983).

100 Forecast, Appendix A, at A-17.

Table 19
System Peak Day Capacity
(MMCF PER DAY)

Source	1983/84	1984/85	1985/86	1986/87	1987/88
AGT F-1	127.1	127.1	127.1	127.1	127.1
ST-1	29.7	29.7	29.7	29.7	29.7
WS-1	48.2	48.2	48.2	48.2	48.2
SNG-1[a]	12.2	12.2	12.2	12.2	0.0
Trans-Niagara	0.0	0.0	0.0	7.0	7.0
TGP CD-6	96.0	96.0	96.0	96.0	96.0
Boundary	0.0	0.0	9.9	9.9	9.9
Propane	72.9	72.9	72.9	72.9	72.9
DOMAC LNG	66.6	63.7	60.3	57.0	59.9[b]
LNG Storage	202.9	202.9	202.9	202.9	202.9
SNG Plant	40.0	40.0	40.0	40.0	40.0
Total	695.6	692.7	699.2	702.9	693.6
Peak Sendout	669.3	675.6	681.6	687.6	693.6

Source: *Forecast*, Table G-23.

a January only.
b Includes 9.9 MMcf/day of best-efforts vaporization.

Table 20
Peak Day Capacity by Division, 1983
(MMCF PER DAY)

Division	Peak Day Sendout	Sendout Capacity	Inter-Connection	Backup Capacity	Portable LNG Capacity	Maximum Divisional Total
Boston/Norwood	390.7	527.7	+93.2	102.5	0.6	724.0
Mystic/Lynn	189.7	143.4	+93.2	28.8		265.4
North Shore	39.8	55.4		15.0		70.4
Southbridge	10.6	15.4			0.6	16.0
Leominster	10.0	14.2			0.6	14.7
Gloucester	7.4	8.8			0.6	9.4
Spencer	4.5	7.9			0.6	8.5
Clinton	3.0	2.8			0.6	3.4
System[a]	655.7	695.6	0.0	146.5	1.2	843.3

Source: *Forecast*, Table G-14 and Appendix A, at A-17; Response to Data Request S-12; 9 DOMSC 1, 70-1 (1983); Table 10; Table 19.

a System capacity is the maximum peak day capacity available to Boston Gas as a whole from each source. System capacity can be less than the sum of the capacity for the individual divisions. It does not include minor interconnections with other gas companies that are not firm on-peak.

The Council therefore concludes that the Company has adequate sendout capacity to meet peak sendout requirements.

C. Sensitivity to Supply Assumptions

The Council has identified several contingencies that might have a substantial impact on how the Company uses its resources to meet its sendout requirements. The Boundary Gas project might be delayed beyond its projected 1985 starting date; the Trans-Niagara project beyond 1986. The Company should also prepare to meet firm requirements during extended periods of extremely cold weather, and in the event of a disruption of LNG supplies from DOMAC.

This section evaluates the Company's ability to meet its design requirements under each of these contingencies. For purposes of review, the contingencies are divided into two types. Long-term contingencies, including delays in the Canadian gas projects and curtailment by TGP or AGT, are events of which the Company should receive notice well in advance of occurrence. These contingencies require monitoring, but not short-term responses. Supply disruptions, in contrast, are unexpected events that require immediate response in the form of extra resources and built-in redundancy. The two types of contingencies are discussed separately in the sections that follow.

1. Long-term Contingencies

In response to inquiries by Council Staff concerning delays in the availability of Canadian gas, the Company stated that it

> "... does not add firm load in anticipation of deliveries of new gas supplies....If these volumes are not available as forecast, the Company would not add the associated firm load and its forecasted requirements would decrease accordingly."[101]

However, deferral of load growth in itself is not sufficient to compensate for delays in the Canadian gas projects. Boston Gas forecasts that its design firm sendout requirements will increase by approximately 580 MMcf annually, or 2320 MMcf by 1987/88 (see Tables 17 and 18). The Company forecasts usage of 4571 MMcf of Canadian gas in a normal year, with 6229 MMcf available to meet design. Though Boston Gas can reduce its need for the Canadian volumes by not adding firm load, the Company must take other steps to replace these volumes in full.

Given sufficient notice of curtailments or delays in new projects, the Company has several options for obtaining replacement supplies. It can take additional gas from storage. It can plan in advance to reduce its interruptible sales until storage inventories are returned to required levels. Within any given season, it can purchase additional supplies of LNG and propane on the spot market.

Moreover, the Company faces a variety of contingencies that tend in the opposite direction; i.e., new sources of gas whose availability is not yet certain. If FERC does not approve the Company's proposed reductions in annual contract quantities of DOMAC LNG by April 1, 1984, or if gas becomes available from the CONTEAL project, the Company will have gas supplies in excess of what has been forecast. Alternatively,

101 Response to Data Request S-7B.

the Company can reduce its gas sendout requirements on a seasonal basis through encouragement of energy conservation.

Given the likelihood that the Company will receive notice in advance of these problems, as well as the options and potential options available to the Company for handling seasonal supply problems, the Council hereby concludes that the Company has sufficient resources to cover the aforementioned long-range contingencies.[102] At this point, we wish to remind the Company of its obligations under EFSC Administrative Bulletin AB 81-3:

> "...all Gas Companies are hereby required to notify the EFSC...of any disruptions in their supply plan as forecast and last approved by the Council as soon as a disruption or potential for disruptions is known to the Company."[103] (emphasis added)

We note that positive confirmation of curtailment or delay in receiving new supplies that are required to meet forecasted sendout is a "potential disruption", and the Company is therefore required to keep the Council informed.[104]

2. Short Term Contingencies

a. DOMAC LNG Supply Disruptions

Boston Gas has a stated policy of planning "...to meet the needs of its customers in a design year in the event of a complete interruption of winter Distrigas deliveries."[105] Table 21 shows the Company's extra sendout requirements for a design heating season in the event of a complete disruption of DOMAC LNG deliveries. It also shows the resources available to the Company to meet those requirements.

The table shows that Boston Gas has ample supplies to meet design requirements on a seasonal basis during the next four heating seasons in the event of a complete interruption of winter DOMAC LNG deliveries. Moreover, the Company might retain access to sufficient resources for the 1987-8 heating season by renewing its propane terminalling contract with Dorchester Sea-3 for an additional year.

However, as the Council has already noted, not all of these resources are firm. Acquisition of gas from underground storage depends on the availability of transportation. Acquisition of propane supplies depends on the timeliness of spot propane purchases and deliveries, as well as the availability of trucks to transport propane from storage

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102 Albeit through fuller use of its existing resources, which may make it more vulnerable to a short-term supply disruption. See VI.C. 2.b., infra.

103 EFSC AB 81-3, issued August 5, 1981.

104 The Company informed the Council of a possible supply disruption in October, 1982, when an LNG shipment was delayed (9 DOMSC 1, 81,(1983) Note 49A). The Council hereby commends the Company for its communication in that matter.

105 Forecast, S.1., at 11. See also section V.A.1.d, supra.

TABLE 21

Comparison of Resources and Requirements in
the Event of a DOMAC LNG Disruption
Design Heating Season
(MMCF)

REQUIREMENTS	1983/4	1984/5	1985/6	1986/7	1987/8
Normal DOMAC Deliveries (From Table G-22)	6944	6701	6425	5915	5535
Excess Design Sendout	3717	3754	3785	3820	3852
TOTAL	10661	10455	10210	9735	9387
RESOURCES					
AGT Underground	1246	1246	713	738	555
TGP Underground	1673	1638	1645	1634	1586
LNG Storage	2078	1447	1651	1607	773
Propane-air	533	526	525	524	512
Interruptible Sendout	1741	1538	2210	1682	1487
Sea-3 Propane[a]	4587	4587	4587	4587	0
TOTAL	11858	10982	11331	10772	4401

Source: Tables 16 and 18; Forecast, Table G-22. The CONTEAL and Canadian gas projects, not yet approved by FERC, are not included here.

a Supplies available on the spot market for terminalling at the Sea-3 facilities.

and terminalling facilities to the Company's service territory.[106] Use of the acquired supplies depends on the availability of sendout facilities and supplies to match varying daily load requirements.

The Council concludes that the Company has (or can purchase) sufficient supplies of gas to meet design requirements in the event of a complete interruption of winter DOMAC deliveries, but remains concerned about the timing and availability of these supplies. These concerns are best addressed in the context of a "cold snap", during which the Company must have a full complement of resources ready to meet sendout requirements. See Section VI.C.2.b., infra.

b. Cold Snap

The Council has defined a cold snap as "a number of days in succession during the heating season at or near design conditions."[107] To meet cold snap requirements, a gas company must maintain high rates of sendout over an extended period by supplementing its pipeline supplies with additional capacity (LNG, LPA or SNG), and by storing or having access to sufficient quantities of supplemental fuels.

The Company's facilities and storage capacity for meeting cold snap needs during the 1983/84 heating season[108] are described in Table 22. When its storage facilities are full, Boston Gas can meet sendout requirements for more than two weeks at peak day levels, or for almost a month at an average of 50 degree-days per day. With its storage facilities half full, Boston Gas can withstand seven consecutive peak days, or two weeks of sendout on days averaging 50 degree-days.

Maintenance of LNG inventory levels is critical to the Company's ability to meet cold snap requirements. LNG is required on days when the degree-day total is 44 DD or greater, because the Company's sendout requirements exceed the sum of its pipeline, SNG and normal propane-air daily sendout rates. Even if Boston Gas produces SNG and propane-air at 112.9 MMcf per day, it requires 255.4 MMcf per day of LNG vaporization on a peak day and a minimum of 912.8 MMcf of LNG over a two week cold snap that averages 50 DD per day.

The Company's LNG inventories are scheduled for replenishment every 24 days by its entitlement of 916.4 MMcf of LNG from DOMAC shipments (every 17 days under the proposed DOMAC contract amendments). If these supplies arrive as scheduled, Boston Gas can maintain its LNG inventories at sufficient levels to meet cold snap requirements throughout the heating season.

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106 7 DOMSC 1, 17, 70-71 (1982).

107 9 DOMSC 1, 75 (1983). Boston Gas experienced a cold snap between December 31, 1980, and January 13, 1981. This two-week period contained 703 degree-days, which is an average of 50 degree-days per day. See DPU 555, Exhibit BGC-25.

108 Cold snap analyses for the other heating seasons during the forecast period yield substantially the same results.

TABLE 22
Cold Snap Resources and Requirements
1983/84 Heating Season
(MMCF PER DAY)

A. Daily Sendout Capacity

	50 DD	60 DD	70 DD	73 DD
(1) Firm Sendout	479.1	561.8	644.5	669.3
(2) Pipeline Gas[a]	301.0	301.0	301.0	301.0
(3) Required supplementals: LPA, SNG, LNG [(1)-(2)]	178.1	260.8	343.5	368.3
(4) Firm LPA and SNG capacity[b]	112.9	112.9	112.9	112.9
(5) Minimum required LNG capacity [(3)-(4)]	65.2	147.9	230.6	255.4

B. Supplemental Storage Capacity

	50 DD	60 DD	70 DD	73 DD
Total supplemental capacity	5337.1	5337.1	5337.1	5337.1
Days' storage [See (3)]	30.0	20.5	15.5	14.5
LNG storage	5158.0	5158.0	5158.0	5158.0
Days' storage [See (5)]	79.1	34.9	22.4	20.2
LPA storage	179.1	179.1	179.1	179.1
Days' storage [See (4)]	1.6	1.6	1.6	1.6
LPA storage including Sea-3	712.1	712.1	712.1	712.1
Days' storage [See (4)]	6.3	6.3	6.3	6.3

Source: Forecast, Tables G-14 and G-23, Appendix A, at A-12; Table 21.

a Includes firm AGT and TGP supplies, WS-1 and firm storage return. The Company's pipeline gas supplies are adequate to meet sendout requirements on days of 30 degree-days or less.

b Backup capacity not included.

However, the ability of DOMAC to deliver LNG as scheduled must be viewed with caution (V.A.1.d., supra). If LNG shipments are interrupted, Boston Gas needs to keep its LNG inventories at safe levels in order to be prepared for a cold snap.

The Company has several options for meeting daily sendout requirements while maintaining safe LNG inventory levels. If required, Boston Gas states that it would "exercise its agreement with Dorchester Sea-3 to purchase sufficient quantities of propane..."[109] The Company already owns propane in storage at Sea-3's facilities in Newington, NH. It can purchase additional spot supplies from other distribution companies or suppliers. It can arrange "swaps" with other companies that store gas in the DOMAC LNG tank and with whom it maintains displacement agreements (see V.B.3., supra). It can temporarily store more than 643 MMcf in the DOMAC LNG tanks.[110] During January, the Company will be sending out SNG-1 in addition to its other pipeline supplies.

On the other hand, the Company does not have much propane storage capacity in its service territory, and would need to continually replenish its propane inventories if it is to maintain high rates of SNG and propane-air sendout during a cold snap. Of the 5337.1 MMcf of supplemental gas storage in its service territory, 5158 MMcf is LNG and 179.1 MMcf is propane. This is less than two days of storage for maintaining SNG and propane-air production at 112.9 MMcf per day. If the propane supplies stored at the Sea-3 facility in Newington, N.H., are included, the Company can produce SNG and propane-air at 112.9 MMcf per day for less than seven days. Storage will be depleted even more quickly if the Company uses its backup propane-air facilities to maintain sendout above 112.9 MMcf per day.

We find that Boston Gas will be prepared to meet cold snap requirements if it maintains its LNG inventories at safe levels and if it is able to move propane to its service territory as required. Still, the Council is concerned that the Company's ability to maintain LNG inventories at safe levels to meet cold snap requirements during a disruption of LNG shipments depends on having sufficient notice that a disruption will occur, sufficient time to acquire and transport additional supplies (LNG or LPA), and sufficient resources to maintain a trucking network between out-of-state propane terminalling or storage facilities and its service territory. Further, we are concerned as to how Boston Gas's demand for propane and propane trucks might affect the availability of trucks for other gas utilities that need to obtain propane supplies on the spot market.

We therefore CONDITION the approval of this forecast on the Company's discussion of these issues in its next filing. Specifically,

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109 1982 Forecast, p. A-12.

110 By contract, Boston Gas can store up to 1667 MMcf at DOMAC between December 1 and March 31, though storage levels must be reduced to 643 MMcf before an LNG ship arrives to allow space in the DOMAC tanks to unload its cargo. During the 1982-3 winter, for example, DOMAC inventories averaged 1017 MMcf, varying between 410 and 1419 MMcf. See EFSC 82-25, Document Request 2, Copies of Contracts; EFSC 83-25, Response to Data Request D-IV.

the Council ORDERS the Company to discuss the most likely sources of LPA (or LNG) to which the Company would turn in the event of an LNG disruption, including names of suppliers, and estimates of the time required between initial contact and conclusion of the supply agreement. For supplies that arrive by ship, the Company should estimate the time required to ship LNG or propane from each supplier to the terminal; the Company's judgement as to whether propane deliveries can be terminalled at the Sea-3 facility in Newington in less than the 60 days required by the Sea-3 contract; and the number of trucks and frequency of truck trips required to bring the propane to the Company's service area. For supplies that arrive by truck or rail, the Company should discuss the arrival point of the propane, the time required to transport propane from the source to the arrival point and the number of trucks and frequency of truck trips required to bring the propane to the Company's service area. If it so desires, the Company can use the list of suppliers referenced in Appendix A of its 1982 Forecast as a basis for compliance with this Condition, which is appended to this Decision as Condition 4.

D. Summary: Sendout Analysis

Boston Gas has shown that it has sufficient supplies and facilities to meet normal design, peak and cold snap sendout requirements subject to the Conditions stated herein. The Company has reduced its contractual take of its highest cost supply, SNG-1, and retains flexibility for dispatching its other supplies. Amendments to the Company's contract with DOMAC, its main supplier of Algerian LNG, are awaiting FERC review, as are two projects to import gas from Canada (Boundary and Trans-Niagara) and one project to increase deliveries of domestic gas (CONTEAL).

The Company has been ORDERED to comply with two Conditions: one regarding its negotiations with DOMAC; the other related to the timing and availability of propane and LNG to meet cold snap requirements in the event of a major supply disruption. These Conditions are affixed hereto in Section VII as Conditions Number 3 and 4.

VII. DECISION AND ORDER

The Council hereby APPROVES conditionally the Second Supplement to the Second Long-Range Forecast of Gas Needs and Requirements of the Boston Gas Company and Massachusetts LNG, Inc. In its next supplement, to be filed with the Council on July 1, 1984, the Council hereby ORDERS:

1. That the Company correct the inconsistencies in its treatment of non-heating season temperature-sensitive load growth in its next filing. The Company should distinguish between temperature-sensitive load growth and decreases in temperature-sensitive consumption by existing customers during the non-heating season, and should document its assumptions. Moreover, if the Company implicitly assumes that conservation will occur, or if it accounts for conservation in its variable heating increment algorithm, the amount of rate of conservation should be stated explicitly.

2. That the Company account for reduced consumption by existing customers in its next filing as shown by its meter-reading study,

data base reports, and other data analyses or studies. The Company should state explicitly its source(s) of data for determining the reductions in consumption per customer and its judgements in interpreting the data. The Company should also describe in detail how forecasted reductions are allocated between the heating and non-heating seasons, between base load and temperature-sensitive load in each season, and between peak and off-peak degree-day intervals for temperature-sensitive load in each season. The Company should meet with Council Staff within ninety days to discuss compliance with this Condition.

3. That the Company use all due diligence in all future negotiations to seek remedies that will reasonably reduce its costs and risks, such as reductions in its take-or-pay obligations, further reductions in its total Distrigas LNG volumes, or pursuit of other contractual remedies that will reduce the Company's LNG associated costs and risks. The Company shall document its efforts in compliance with this Condition in its next Forecast.

4. That the Company discuss the most likely sources of LPA (or LNG) to which the Company would turn in the event of an LNG disruption, including names of suppliers, and estimates of the time required between initial contact and conclusion of the supply agreement. For supplies that arrive by ship, the Company should estimate the time required to ship LNG or propane from each supplier to the terminal; the Company's judgement as to whether propane deliveries can be terminalled at the Sea-3 facility in Newington in less than the 60 days required by the Sea-3 contract; and the number of trucks and frequency of truck trips required to bring propane to the Company's service area. For supplies that arrive by truck or rail, the Company should discuss the arrival point of the propane, the time required to transport propane from the source to the arrival point and the number of trucks and frequency of truck trips required to bring the propane to the Company's service area.

Lawrence W. Plitch, Esquire
Hearings Officer

On the Decision:
George Aronson, Lead Gas Analyst

Unanimously APPROVED by the Energy Facilities Siting Council on March 5, 1984 by those members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paula W. Gold, Secretary of Consumer Affairs); Walter Headley (for James S. Hoyte, Secretary of Environmental Affairs); Joellen D'Esti (for Evelyn F. Murphy, Secretary of Economic Affairs); Robert W. Gillette (Public Environmental Member); Thomas J. Crowley (Public Member Engineering).

March 22, 1984
Date

Sharon M. Pollard
Sharon M. Pollard
Chairperson

Energy Facilities Siting Council
Room 1506, 100 Cambridge Street, Boston, Massachusetts 02202 - (617) 727-1136

MEMORANDUM

From: Paul T. Gilrain, Esq., General Counsel;
George Aronson, Economist

To: EFSC Docket No. 83-25

Re: Boston Gas Company's Compliance with Condition Number 11 of EFSC Decision and Order No. 82-25.

Pursuant to Condition 11 of the 1982 Decision and Order of the Council approving the Boston Gas Company's First Annual Supplement to the Second Long-Range Forecast, Council Staff met with representatives of the Company on December 10, 1982.[1] The meeting focused primarily on how the Company should respond to the ten conditions of the Council's Decision. For purposes of discussion, the conditions were divided into three categories: conditions of ongoing concern regarding how the Company models changes in customer usage patterns for the forecast of sendout requirements (Conditions 1, 2, and 4); conditions regarding the use, documentation, or presentation of data for the forecast of sendout requirements for which specific actions are required for the next supplement (conditions 3, 5, 6, and 7); and conditions related mainly to gas supply planning (Conditions 8, 9, and 10). The discussion surrounding compliance with each of these conditions is summarized below.

Conditions Regarding How the Company Models Changing Customer Usage Patterns

Conditions 1, 2, and 4, which are in this category, are as follows:

1 See Attachment A for list of attendees.

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;

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;

Condition 4 refers to the treatment of the heating increments that are used in the ABCGAS model; Conditions 1 and 2 refer to adjustments of model output done specifically for use in the EFSC filing. These conditions also address the treatment of "conservation" for forecasting purposes, which has been an issue of concern in several previous Council decisions.

Four long-term approaches to the modeling problem were discussed, including:

- use of the heating increments to forecast changing usage patterns;
- use of "Conservation rates" with the model output to calculate how sendout requirements will change;
- use of a combination of heating increments adjustments and conservation rate adjustments to the model's output;
- sensitivity analyses to determine the possible impacts of changes in usage patterns.

The Company is currently engaged in several data collection efforts to improve its understanding of usage patterns, including a daily residential metering project, and is considering doing an appliance saturation survey. Furthermore, the Company will be studying the value of disaggregating its sendout data by customer class while it produces an allocated cost-of-service study for the DPU.

In view of the efforts in progress, the Staff agreed that the Company could wait until it can analyze these efforts before deciding on a specific long-term modeling strategy. The Staff suggested that the Company meet with Council staff as necessary to discuss how to use their new data and knowledge in their forecasts.

For the next supplement, the Staff expressed its belief that the conditions could be satisfied by documenting current practices. Condition 1 would require the Company to state the conservation rates that it uses for each class, to state the source of those rates, and to state the status of the data collection efforts in progress that affect each stated rate. Condition 2 would require the Company to justify its conservation rates over time either by stating the relationship of price, etc., to conservation rate, or by presenting a brief discussion of the magnitude and direction of variations from expected rates and a sensitivity analysis that highlights the effect of rates that vary from those forecast. Condition 4 would require a description of the annual reconciliation process for updating the heating increments and base load data by comparison with 60-day average figures, the numerical results of the most recent reconciliation, and a statement of the level of confidence in future projections of heating increments and base load data in the short- and long-term. Furthermore, the Company agreed to supply the forecast of baseload and heating increments by degree-day range in the format suggested in Attachment B.

Conditions Regarding the Use, Documentation, or Presentation of Data

Condition 3, 5, 6, and 7 are in this category.

Condition 3 requires:

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

Leo Silvestrini stated that the Company periodically reconciles the data bases with the sendout for the entire class, and that, because of the large sample size, the data base tends to be an unbiased estimator of the population. A brief description of the reconciliation process, along with the results of the most recent reconciliation, would fully satisfy this condition.

Condition 5 requires:

> 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;

George Aronson presented a graph of sendout vs. temperature or degree-day level that illustrates the problem addressed by this condition (see Attachment C); namely, if load growth is added to each degree-day range in the way described during discovery, too much load is added in the 40-50 degree day range, which creates a discontinuity in the load-temperature curve. The Company acknowledged the problem and agreed to improve its new load distribution method and document its assumptions in the next supplement.

Condition 6 requires:

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

The Company stated that it does not currently forecast peaks by divisions, and that the facility applications for Spencer (82-25) and Danversport (82-25A) required special data analysis. Furthermore, the Company is in the process of changing its computer dispatching system, and would prefer to defer detailed peak forecasting by division until the system is in place. George Aronson suggested that rough calculations of peak by division based on data like that given in Table S-6 of the Decision would be sufficient, along with a report on the status of future plans in this area.

Also discussed was the issue of weather data. Boston Gas uses Logan Airport weather data to predict sendout in all of its sendout divisions, including Spencer, Southbridge, Clinton and Leominster, mainly because other data sources are either less available or of questionable reliability. The Staff agreed that Condition 6 does not require action on this issue, but suggested that the weather issue may be considered during the next forecast review, especially if the DPU has completed its review of this issue in conjunction with 555.

Condition No. 7 requires:

> 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;

Barbara Sagan stated that the Company has completed about 80% of the SIC coding. The coding will probably be done by next year: problems include maintenance of SIC coding among customer classes that turn over quickly during the year, and in identifying the codes of individual customers. The latter problem will be addressed with a company-wide manual on SIC coding.

For the next forecast, the Company agreed to attempt to submit separate data for commercial and industrial customers if the SIC is done, and, if not, to describe the status and list the problems causing delays. The Company cautioned that in the first year, the forecast for each class will need to be based on judgement due to insufficient historical data by class. The Staff agreed that it was neither necessary nor desirable for the Company to use their SIC codes to estimate historical sendout data by class, and suggested that the Company document their judgements in the text of the supplement.

Conditions 8, 9, and 10 were discussed briefly with the Company. Condition 10 required 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 the division."

The purpose of this condition is self-evident; thus, the Company acknowledged its intent to comply.

Conditions number 8 and 9 were discussed together as they deal with the same general issue. They were:

> 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;

Condition number 5 of our last decision and order dealt with assessing the tradeoffs between various sources of peak shaving supplies.

"5. That the Company assist the staff in evaluating the trade-offs between additional storage and the deliverability and security of supplemental resources, including propane, vaporized LNG and liquefied LNG."

The Company was concerned that they were being singled out unduly to do work which is more properly considered on a regional level. The staff assured them that the issues were, in fact, to be assessed by the Council staff and that the Company was only being ordered to cooperate with the staff in this effort.

ATTACHMENT A

List of Attendees

EFSC: Paul Gilrain, Chief Counsel and Hearing Officer
Larry Plitch, Senior Counsel
George Aronson, Economist

Boston Gas: Jennifer Miller, Counsel
William Luthern, Manager of Gas Supply
A. Leo Silvestrini, Manager of Rates and Regulatory Affairs
Barbara Sagan, Manager of Marketing

ATTACHMENT B

Documentation of Base Load and Heating Increments
by Degree Day Range
(as used in the ABCGAS model)

1. Heating Season

Split Year	Base Load	HEATING INCREMENTS (MCF/DD) 10-20	20-30	30-40	40-50	50+
1983-4						
1984-5						
1985-6						
1986-7						
1987-8						

2. Non-Heating Season

	April - August				September - October			
Split Year	Base Load	Heating Increment 0-10	10-20	20+	Base Load	Heating Increment 0-10	10-20	20+
1983-4								
1984-5								
1985-6								
1986-7								
1987-8								

ATTACHMENT C

Daily Sendout by Temperature and Degree-days
Heating Season