DECISION AND ORDERS

MASSACHUSETTS ENERGY FACILITIES SITING COUNCIL

VOLUME 11

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Approved by Daniel D. Carter, State Purchasing Agent

TABLE OF CONTENTS

TABLE OF CONTENTS

I. INTRODUCTION

The Council hereby APPROVES conditionally, the Second Supplement to the Second Long-Range Forecast of Electric Loads and Power Facilities Requirements ("Forecast") of the Northeast Utilities System ("NU", "the System" or "the Companies"). The Council reviews the background and history of the proceedings in section II; the scope and standards of review in section III; NU's demand model in section IV; NU's supply plan and its cost/benefit analysis of its 80s/90s programs in section V; and issues its Decision and Order in section VI.

II. HISTORY AND BACKGROUND OF THE PROCEEDINGS

NU is a public utility holding company which owns all of the outstanding shares of its Massachusetts and Connecticut subsidiaries. The EFSC has jurisdiction over the System's two companies in the Commonwealth; the Western Massachusetts Electric Company (WMECo) and Holyoke Water Power Company (HWP). The System's Massachusetts service territory is responsible for about 17% of NU's total electric sales, making NU the third largest electric company in this state, serving approximately 164,000 residential customers. As a system, NU is the largest electric utility in New England.

WMECo's service area consists of 59 municipalities and covers 1484 square miles. More than half of all retail electric consumption occurs in the Springfield-Chicopee-Holyoke SMSA and 15% in Pittsfield. The remainder of the service area is rural with some small towns in Greenfield and Amherst. HWP serves industrial customers in the City of Holyoke and sells wholesale power to its subsidiary, Holyoke Power and Electric Company and to the City of Chicopee Electric Department. HWP sales represent less than 3% of total System sales.

NU submitted its Second Supplement to its Second Long-Range Forecast on April 1, 1983, pursuant to the requirements of Massachusetts General Laws, Chapter 164. No new facilities were proposed. The Council ordered publication of a notice of public hearing and adjudicatory proceedings in newspapers of general circulation within NU's Massachusetts service territory. There were no intervenors. Through verbal request of the Council Staff, the Companies provided four supplemental documents concerning NU's conservation programs under a cover letter dated September, 1983. Council Staff prepared Information Requests in the fall of 1983. Timely responses were received on December 22, 1983. On January 22, a Technical Session was held at the System's headquarters in Berlin, Connecticut. Additional record information was received by the Hearing Officer during the following month, and the record was closed on February 10, 1984. The projections contained in this Supplement are for the ten-year period, 1983 through 1992.

The Council's most recent NU Decision in review of the System's 1981 Long-Range Forecast, imposed two Conditions, as follows:

(1) That the System submit to the Council a specific, long range, cost/benefit analysis of each of the conservation programs and alternate energy sources outlined in the NU Program for the 80's and 90's; and

(2) That the System meet with the Council staff to present an outline of the cost/benefit analysis which the Companies proposed to utilize (8 DOMSC 146).

Compliance with these Conditions is addressed in Section V, supra.

III. SCOPE AND STANDARD OF REVIEW

The provisions of the Massachusetts General Law, Chapter 164, Sections 59H-J, mandate that each forecast accurately project "the electric power needs and requirements of its market area...for the ensuing ten year period". The Council evaluates demand forecasts on the following criteria. NU's filing will be deemed reviewable if it contains enough information to allow a full understanding of the methodology. If this threshold of documentation is passed, we will examine whether it is appropriate, or technically suitable. Lastly, the forecast will be judged reliable if it provides confidence in NU's customer requirements through the year 1992.

In order to ensure "a necessary energy supply to the Commonwealth with a minimum impact on the environment at the lowest possible cost", the Council focuses its supply review on the adequacy, cost and diversity of supply necessary to meet projected demand. The adequacy of supply is measured by is a company's ability to provide capacity sufficient to meet projected loads and reserves over the forecast period. The review of the cost of supply addresses long-run system cost minimization subject to the constraints of adequacy and diversity. The diversity of supply is a criterion determined by the relative mix of energy sources used. Our working principle is that a more diverse supply is less risky.

IV. REVIEW OF THE DEMAND FORECAST

A. OVERVIEW

In 1982, WMECO, which is NU's only retail electric company in the Commonwealth, was responsible for 16.7% of total System sales, or approximately 10% of total electricity sales by Massachusetts utilities. This percentage is expected to remain roughly unchanged during the next decade. Figure 1 illustrates actual and forecasted retail sales for the System as a whole, with WMECO sales superimposed for comparison.

A combination of econometric and end-use modeling techniques are used to forecast electricity sales. Econometric equations, or regressions, are used to make projections of demand in the residential and commercial sectors in the short run, and the industrial sector in the short run and the long run. This type of analysis explicitly addresses the effect of variables such as price on customer demand. Because there is uncertainty associated with projections based on

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Northeast Utilities System for Approval of the Second Supplement to the Second Long-Range Forecast of Electric Loads and Power Facilities Requirements	)	EFSC No. 83-17

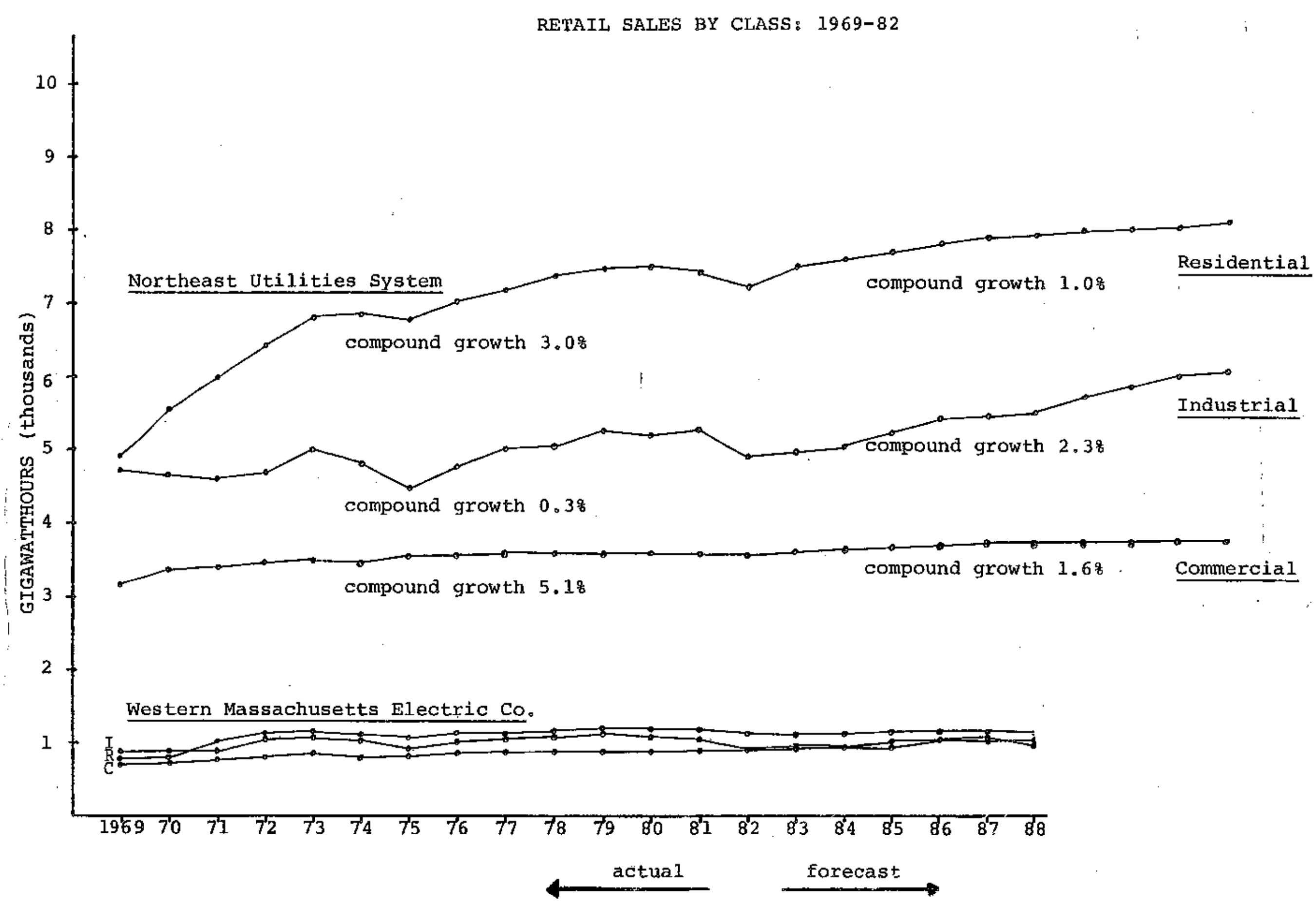
FINAL DECISION

Lawrence W. Plitch, Esq.
Hearing Officer

On the Decision:

James Coyne, Lead Electric Analyst
Karen Grubb, Analyst

FIGURE 1


RETAIL SALES BY CLASS: 1969-82
GIGAWATTHOURS (thousands)
10
9
8
7
6
5
4
3
2
1
Northeast Utilities System
compound growth 3.0%
compound growth 1.0%
Residential
compound growth 2.3%
Industrial
compound growth 0.3%
compound growth 1.6%
Commercial
compound growth 5.1%
Western Massachusetts Electric Co.
I
R
C
1969 70 71 72 73 74 75 76 77 78 79 80 81 82 83 84 85 86 87 88
actual
forecast

relationships between variables which change over time, forecast reliability is a function of the time horizon and the nature and stability of these relationships.

End-use modeling is used to forecast long run residential and commercial sales. This is an engineering approach to demand forecasting. It captures nonprice effects (i.e., changing end-use efficiencies and usage patterns) that drive demand. The application of these techniques in NU's demand forecast will be reviewed below.

The System's 1983 Supplement reflects some timely incremental improvements in its demand forecasting methodology. The Council is impressed with the sensitivity tests on key assumptions in the sectoral models. The Companies' hourly load and weather-normalized modeling efforts are also noteworthy. NU's currently planned forecasting improvements, provided to Council Staff, indicate the Companies' continued dedication to strengthening its forecasts.

Two areas of weakness are evident in NU's 1983 forecast. First, improvements in the quality of forecast data have generally not kept pace with the Companies' methodological developments. The most formidable constraints are imposed by limitations on the necessary inputs for the new data-intensive end-use models. Second, documentation is inadequate throughout much of the demand forecast. In our last NU Decision we recommended that the Companies improve their forecast documentation. The response of NU to this suggestion has been disappointing. Consequently, we now order the Companies to expand its forecast documentation to comply with EFSC Rules 63.5 and 69.3. The Council's detailed recommendatons in our last Decision should also be heeded (8 DOMSC 117) in Condition 1.

In the following sections, the Council reviews each major component of the current forecast in greater detail.

B. DEMOGRAPHICS

Demographic data are crucial to NU's sales projections. The results of intermediate econometric equations and independent DRI forecasts serve as inputs to the sectoral demand models.

Residential customer estimates are used in NU's residential and commercial demand forecasts. For the long run (1987-92), NU uses DRI's state housing stock forecast to estimate the number of residential customers. For the short run (1983-86), NU estimates changes in the housing stock with a stock adjustment model. Annual changes in the housing stock are estimated as a function of the difference between the desired stock each year and the actual stock from the previous year. Actual values for the current and previous year housing stock are available. The desired stock, however, is not directly quantifiable, so instrumental variables which are hypothesized to be highly correlated with desired stock are substituted into the equation. The result is a regression which estimates the relation between annual changes in the housing stock, the housing stock the previous year and, to capture the desired housing stock, real per capita disposable income and real effective mortgage rates on conventional fixed thirty year loans.

There are unresolved problems with this model. The Council is concerned because these results serve as the inputs for NU's projected number of customers through 1986. The regression was run using ordinary least squares (OLS) estimation techniques. The R-squared indicates that 97% of the variation in the dependent variable was explained by the independent variables. Although this seems quite high, time series regressions are often characterized by high R-squareds, and this is especially true with autoregressive models. The only regression coefficient that is statistically significant at the 5% level of confidence is the lagged dependent variable. The constant term, income and interest rates are not even marginally significant. Clearly, these results do not support the model as it is specified.

Another problem with this regression, one that often plagues time series analysis, is that of serial correlation. This is evidenced by nonrandom patterns in the error term which express factors that affect the dependent variable but are not explicitly addressed in the model. The Durbin-Watson d-statistic, which tests for serial correlation, falls within the inconclusive zone for acceptance of the hypothesis of no serial correlation at the 5% level of confidence. In addition, when computing a d-statistic in a stock adjustment model there is a built-in bias against discovering serial correlation. As an alternative, Durbin's h-statistic is appropriate when a sample size is large, but this one is not, so we are left with no test for serial correlation. If it does exist, the test statistics are invalid and give rise to misleading conclusions about the significance of the estimated regression coefficients.

The number of state-wide residential customers is estimated, using OLS, as a function of these housing stock estimates and data on government subsidized housing. The independent variables, including a constant term, were all statistically significant. NU's annual share of state-wide customers are calculated as a function of the historic ratio of customers in its service territory to customers in the state. In future filings the Council would like to know the basis for any assumptions that NU makes to render statewide data area-specific.

In addition, demographic data is used by DRI in its forecast of state employment growth. These projections are inputs to NU's commercial end-use models. Inherent in this methodology is the assumption (undocumented) that NU's service territory will experience the same patterns of employment growth as the Commonwealth as a whole. Nonmanufacturing employment is held at a constant share of total state employment since no definite historic trend in that ratio could be identified. Manufacturing employment in NU's service territory is assumed to grow at the same rate as the state in 1983. Thereafter it is assumed to decline as a share of the state because NU's service territory is dominated by SICs which are expected to grow at a slower rate.

In order to facilitate the continued development of these important demographic forecasts, NU should re-evaluate its short-term housing stock model, and further substantiate the basis for deriving service area customer and employment forecasts from state-wide forecasts. These directives are incorporated in Condition 2.

C. RESIDENTIAL SECTOR

Sales to the residential class during the forecast period are projected to grow at a compound rate of 1.1% per year. This is less than half of what was experienced by NU over the 1969-82 period. Growth in the number of customers, however, is expected to remain relatively unchanged from previous years, 1.2% compared to 1.1% between 1969-82. Clearly, the slow-down in sales growth that the System projects is attributable to factors other than changes in the number of customers.

The System served approximately 164,000 residential customers in the Commonwealth in 1982. By 1992 it expects to add an additional 18,000 residential customers. (NU performed a sensitivity test which reveals that if the actual number of residential customers is 20% greater than projected, the forecasted compound growth rate of system sales would increase from 1.47% to 1.55%.)

The System forecasts sales separately for the short run and the long run. In the short run, an econometric model developed by NU staff, which explicitly addresses short run economic conditions, is used. For the long run, NU uses an end-use model which captures projected appliance efficiencies and conservation impacts.

1. Residential Econometric Model: The Short Run

The residential econometric model estimates sales separately for electric resistance space heating and fossil fuel heating customer categories. Electric heating use per customer is estimated as a function of lagged use per customer, marginal price, personal income and number of heating degree days.

The variables were converted to natural logs and the equations were then estimated using OLS. Although the R-squared was good, two of the independent variables, heating degree days and personal income, were only marginally significant and the constant term was insignificant. The lagged dependent variable and marginal cost, however, did turn up statistically significant. The Durbin-Watson d-statistic does not dismiss the possibility of serial correlation. This model may be theoretically sound but suffers from constraints imposed by a small sample size.

Use per customer for fossil fuel heating customers is estimated similarly except that cooling, rather than heating, degree days were considered. The regression results were quite good although, again, the possibility of serial correlation cannot be dismissed. The R-squared was satisfactory and every variable but the constant term turned up significant.

The Council understands that NU will not be using the econometric model for short-run forecasting in its upcoming 1984 Forecast. (Response to Second Staff Information Requests, No. 1.) Given the value of an econometric cross-check on end-use models, we urge the Companies to continue working with econometric models and exploring methods for linking these methodologies. In the Council's view, the two metodologies, in combination, offer the most reliable means of forecasting.

2. Residential End-Use Model: The Long Run

NU uses an end-use model to forecast long run sales. Sixteen household appliances are considered, all if which are major users of electricity. These include electric space heating, heat pumps, renewable resource and fossil fuel heating backup systems, water heating, air conditioning, refrigeration, etc. Long run residential sales are projected as a function of appliance penetration and intensity of use. The variables are estimated separately for single- and multi-family dwellings since the former has exhibited historically higher patterns of usage.

First, sales are initialized to the 1982 level. Internal billing data is used to gather information on number of customers. Next, census and building permit data are analyzed to approximate the distribution of customers between single- and multi-family dwelling units. Electric heating customers are disaggregated according to space heat, heat pump or electric assisted renewable resource heating systems. This distribution is based on a 1982 saturation survey of all electric customers. Percentages from the NU saturation survey are applied to the customer estimates within each dwelling type to define the 1982 stock of appliances.

Incremental changes in the initialized stock of appliances are estimated to forecast appliance use beyond 1982. First, the market for new appliances is disaggregated into the new housing market, the replacement market, and the existing market. Penetration percentages are applied to market projections to estimate sales by appliance. These percentages are judgmentally derived beyond 1982. NU does not provide adequate detail about the rationale behind these judgments to allow the Council to properly review them. This concern is alleviated somewhat by the results of sensitivity tests on electric heating and water heating penetrations that reveal relatively small impacts on the overall sales forecast. Use per appliance is projected to decline in future years due to residential conservation, greater appliance efficiency, smaller dwelling size and fewer people per household.

It appears, however, that price does not directly enter the long-run model. It is imperative that NU explicitly incorporate long-run price effects in future forecasts, for it is price that provides the fundamental link between the Companies' supply plans and consumer demand. Absent this link, the Companies are not in a position to optimize their long-range supply plan. Condition 3 addressed this issue.

D. COMMERCIAL SECTOR

Sales to the commercial sector are projected to grow by a compound rate of 1.6% during the forecast period. This is down from 3.3% experienced over the 1969-82 period. Sales are forecast separately for the short run and the long run. A short run econometric model estimates sales as a function of the number of residential customers and the price of electricity. Beyond the first three years, NU uses an end-use model to forecast sales.

1. Commercial Econometric Model: The Short Run

NU's commercial econometric model was developed by its staff in 1982. It empirically estimates sales as a function of electricity prices, the number of customers, cooling degree days and commercial sales from the previous year. The number of residential customers is chosen as an explanatory variable since commercial sales have been shown to be affected by demographic pressures. In addition, the availability of area-specific demographic data enhances the appeal of this specification.

The regression, run using OLS, yielded an R-squared of .91. The electricity price variable, from NU's rate schedules, is the price that is most likely to apply to changes in the quantity of electricity used for commercial purposes. The sign of the coefficient on this variable is negative as one would expect, but it is, at best, only marginally significant. With respect to the other independent variable, NU states (p.11) that, "while other growth variables were tested, the number of residential customers proved to be the most statistically significant".

The coefficient on number of customers has the sign that one would expect, but it too was, at best, only marginally significant. The coefficient on the temperature variable also had the proper sign but turned up only marginally significant. The only variable which was statistically significant at the 5% level of confidence was lagged sales.

As specified, questions could be raised about the explanatory power of this model. However, it should be kept in mind that it is only used to project three years into the future. A dependent variable which is primarily driven by previous values of itself is not so troublesome in the short run.

2. Commercial End-Use Model: The Long Run

To forecast sales beyond 1986, NU uses the same commercial end-use model that it used last year. Sales are forecast for four end-uses: heating, cooling, lighting and other. These are disaggregated into "stores", defined as wholesale and retail trade establishments, and "offices" defined as all other SIC classifications except manufacturing. The Council staff remains unclear on the basis for this delineation. The Systems' response to our concern, as addressed in Staff Information Request C-2-A, provided only a reiteration of what was stated in the Forecast.

The initialized values for sales to the four end uses are, in the words of the System (C-2-B-E), "judgmentally derived because actual service area estimates were unavailable at the time the 1983 forecast was prepared". NU relies on an assortment of "miscellaneous sources". Here again, the Council is unable to adequately review the methodology because of a lack of detail in NU's documentation. The Council is cognizant of NU's difficulties obtaining data to model the commercial sector. Nevertheless, in future filings, even when the inputs to the forecast are judgmentally derived, the Council expects NU to submit a thorough description of all data, assumptions and modes of analyses.

NU regards use per employee as a function of energy efficiency, and therefore classifies all commercial buildings as either "with" or "without" energy efficiency standards. The model is initialized with NU's estimated 1982 level of sales for each building type. New buildings are expected to require one-third less electricity than comparable older buildings. In addition, NU adjusts its sales projections for conservation. Savings accruing to existing customers are expected to result in a 5% reduction in sales by 1992. (Sensitivity tests performed on key assumptions with respect to conservation and efficiency standards reveal relatively small impacts on the System's forecast.)

Changes in this level are expected to be a function of employment growth, electricity's share of total energy use per employee, and the intensity of electricity use per employee. The System defines "potential electricity use per employee" as the actual electricity use in any year plus the use of other fuels converted to electric equivalent units. It is assumed that the average end-use efficiency of fossil fuels is 60% of that of electricity. Potential electricity use per employee prior to conservation is projected to grow at 5% for both types of buildings. These estimates are judgmentally derived because actual service area estimates were unavailable at the time the 1983 forecast was prepared. Here again, NU's estimates appear arbitrary and unfounded since there is no substantive information on their basis.

Electricity penetration rates per employee were projected into 1992. NU used DRI's estimates for electric heating penetration. It is expected to increase from 6.8% in 1983 to 14% in 1992. All other penetration percentages were judgmentally derived by NU staff, and are expected to remain constant throughout the forecast period. Cooling and heating penetration will maintain at 95% and lighting penetration will remain at 100%.

The price of electricity was held constant in NU's commercial forecast "to avoid a double counting effect" extending from the Companies' assumptions concerning ASHRAE Building Standards in new and retrofit construction. It is not evident to Council Staff, however, that this is an adequate mechanism for incorporating price effects. Sensitivity to price tested with the econometric model is significant (Tables S-1, Forecast) and should be explicitly incorporated in the end-use model. Efforts, of course, should be taken to minimize the double counting the Companies are correctly concerned with. This concern parallels that with the residential forecast and is also addressed in Condition 3.

The Council has been informed by NU that it plans to implement a new state-of-the-art commercial end-use model in its 1985 forecast. (Response to Second Staff Information Request, no.1). The Council's initial response to presentation of the so-called "Jackson Model" by Boston Edison, has been favorable, and we look forward to seeing NU's implementation of its version. In Re Boston Edison Co., 10 DOMSC 203, 225-232, March 5, 1984.

E. INDUSTRIAL SECTOR

Sales to the industrial sector are projected to grow at an annual compound rate of 2.1% during the forecast period. This growth is considerably greater than the -0.4% rate experienced during 1969-82. This is, in fact, the only customer class for which NU expects the rate of growth of sales to increase. Although NU anticipates greater increases in sales than were experienced during the last decade, these projections are lower than similar independent forecasts of electricity use by the industrial sector. NU's forecast is also lower than previous in-house projections. Industrial sales are typically sensitive to fluctuations in the economy. Indeed, in the past decade they were considerably more volatile than sales to the other classes.

1. Industrial Econometric Model: The Short Run and Long Run

NU uses an econometric model to forecast industrial sales through 1992. Sales are estimated as a function of the price of electricity and a production index developed by NU staff using DRI data. Production in NU's Massachusetts service territory is a weighted average of industries by SIC. Each SIC component of the production index reflects the percentage of industrial sales attributable to it times its average electric efficiency (KWH per value added).

NU has indicated that it will experiment with alternative groupings in the current year. (Response to Second Staff Information Request, No.1). Whether successful or not, we order the Companies, in Condition 4, to present the results of their investigation with its next filing.

The industrial econometric model projects sales using OLS. The explanatory power of the overall equation and the statistical significance of individual parameters were both satisfactory. Problems with serial correlation similar to those addressed above are again troublesome. However, the Council's main concern with NU's industrial sales forecast is with the inputs to this model--particularly the production index. Sensitivity tests reveal that increasing this index by 10% results in a 12% increase in the forecasted compound growth rate of sales. This is a key variable, and yet it is not sufficiently documented or substantitated in the forecast.

To capture savings beyond what is induced by price, sales projections are discounted by 0.5% annually to reflect conservation, technological change and building standards. By 1992 this adjustment reduces industrial sales estimates by 4.5%. The Companies have indicated that a literature search will be conducted to investigate this assumption. (Response to Second Staff Information Requests, No.1). The Council concurs with the Companies on the need for this further investigation. Consequently, Condition 4 further requires NU to present the results of this investigation with its next filing.

F. OUTPUT REQUIREMENTS AND PEAK LOAD FORECASTING

NU uses an hourly load model to distribute forecasted sales, by sector, into total hourly demand. The residential load shape is quantified in the form of hourly load factors (HDFs). HDFs reflect residential load for every hour. This is calculated, by appliance, as the product of the percentage of the estimated stock being used each hour and the amount of electricity required to operate it. HDFs are a function of the month, week, day, hour and revenue rate. Temperature sensitive HDFs are also a function of expected outdoor temperature. (Temperature data is accessed through a separate input file.) Commercial and industrial load shapes are quantified in the form of hourly load profiles (HLPs) which reflect the fraction of total electricity used during any hour. Commercial HDFs are a function of the requirements of stores and offices and, for temperature sensitive enterprises, expected outdoor temperatures. Likewise, industrial HDFs depend upon electricity demand by SIC.

Total hourly load equals the sum of hourly demand from each customer class. Net electrical energy requirements are projected to grow at an annual compound rate of 1.2%. The period 1969-82 registers a compound rate of 1.6% per year.

NU has documented increasing customer sensitivity to peak winter and summer temperatures. Growth in summer peak output requirements are projected to decline from an annual compound rate of 2.5% to 1.4%. Growth in winter peak output requirements, however, are projected to increase from 1.4% to 1.9% annually.

The Companies' hourly load methodology and its work with weather normalized forecasts are advanced, and commendable.

G. DEMAND SUMMARY

Despite concerns over aspects of the demand forecast raised above, the Council is generally pleased with NU's filing. It reflects NU's continuing efforts to refine its forecast methodology. Nonetheless, the Council finds the following items troublesome.

Inadequate documentation made it impossible to properly review parts of the demand forecast. This has been a recurring problem with NU's submissions to the EFSC. The Council is seriously concerned because many important inputs, such as appliance penetration rates, are presented virtually without explanation or rationalization.

Problems ensuing from inadequate data are manifest throughout the demand forecast. The end-use and econometric models in this forecast would be enhanced if the data were more service-territory specific. Although the Council is cognizant of the scarcity of quality data, we persist with our expectation that future filings reflect improvements in these data.

In addition, the Council sees potential for improvements in NU's econometric modeling. Overall, the models are on firmer ground theoretically than statistically. For example, the regression statistics for the housing stock model suggest insigificance of crucial variables and probable serial correlation. Results from this particular model serve as inputs for NU's projections of number of residential customers.

V. SUPPLY ANALYSIS

A. Introduction

Due to the aggregate nature of NU's supply planning, the Council reviews the supply plan of the System as a whole. As stated by the Company, "Generating capacity has been listed and discussed for the Northeast Utilities System as a whole since loads and required reserve margins in the years ahead and the resulting determination of generating capacity additions depend on the relationship between load and capacity for the total NU system. The two Massachusetts Subsidiaries will, of course, have entitlements in their appropriate shares of future NU generation capacity."[1]

In terms of existing generating capacity, the Massachusetts subsidiaries hold 18% of the system total, including the coal-converted Mt. Tom facility.[2] Of NU's planned new sources of capacity, the Massachusetts subsidiaries hold entitlements to 157 MW (Hadley Falls Hydro - 15 MW; Millstone Unit 3 - 142 MW) of the total System's planned 855.9 MW, or 18.3%.[3] The majority of NU's 65% ownership of Millstone 3 and all of NU's 4.06% ownership in both Seabrook Units are held by the Connecticut subsidiary. Under NU's Generation and Transmission Agreement, however, costs associated with these, and all other System generation, are allocated according to the subsidiary's share of System load rather than actual ownership in a particual unit.

B. Adequacy of Supply

NU has existing and planned capacity that is more than sufficient to meet load and reserve requirements over the forecast period. Table 1 on the following page indicates that the Companies' reserve margin will be in the 36-55% range through 1992. Even without Seabrook Unit II, the System's reserve margin would only be 1% lower in 1992. On-line dates for NU's other major planned generation, Millstone 3 and Seabrook 1, could therefore slip well beyond their planned in-service dates without posing capacity problems for the Companies.

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1. Forecast, Vol. I, p.IV.
2. Forecast, Vol. II, p.III-23.
3. Forecast, Vol. II, p.III-24, 25.

Table 1

Northeast Utilities Projected Resources and Requirements

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Existing Generation[2]	5944.3	5970.1	5864.3	5940.4	5913.5	5860.7	5859.9	5870.9	5871.5	5729.5	5626.5
Hadley Falls Hydro		15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Seabrook I			46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7
Millstone III					747.5	747.5	747.5	747.5	747.5	747.5	747.5
Seabrook II							46.7	46.7	46.7	46.7	46.7
Total Capacity	5944.3	5985.1	5926.0	6002.1	6722.7	6716.6	6715.8	6726.8	6727.4	6585.4	6482.4
Winter Peak	3975.0	4094.0	4205.0	4289.0	4354.0	4424.0	4504.0	4565.0	4634.0	4678.0	4757.0
Reserve Capacity	1969.3	1891.1	1721.0	1713.1	2368.7	2292.6	2211.8	2161.8	2093.4	1907.4	1725.4
Reserve %	49.5	46.2	40.9	39.9	54.4	51.8	49.1	47.4	45.2	40.8	36.3

1. From Forecast, Vol. II., p.III-28, Table E-17.
2. Includes purchases and sales, and accounts for retirements and reratings.

The Council's sole concern with respect to NU's projected supply-demand balance is apparent capacity in excess of the system's projected requirements throughout the 1980's. The Council is aware that NU is continuing to attempt to sell its ownership in both Seabrook Units,[4] and that NU has intermediate oil-fired units available for sale to interested utilities on a short-term or long-term basis.[5] The Council is further aware that capacity in excess of short-term requirements may in some cases, offer long-term savings to ratepayers, or reduced rates through lower running costs than existing capacity. The Council, however, urges the Companies to continue to evaluate capacity requirements and to aggressively negotiate sales contracts for any deemed excess where such sales will lower the system's revenue requirements.

C. Cost and Diversity of Supply

The cost and diversity of NU's supply plan hinge directly on the outcome of the Companies' efforts in four major areas of generation planning and demand management: Nuclear units under construction; coal conversions; renewables and cogeneration; and conservation and load management. The Companies' plans in these areas were originally set forth in Northeast Utilities Conservation Program For the 1980's and 1990's in January, 1981. The Council, having reviewed this program in our most recent NU Decision,[6] now focuses on the Companies' progress in implementing these programs designed to reduce oil consumption and to expand customer conservation activities.

1. Nuclear Units Under Construction

Millstone Unit 3 is a 1150 MW nuclear unit under construction in Waterford, Connecticut, presently scheduled for completion in May, 1986.[7] The Companies estimate that the unit, 77.7% complete as of September, 1983, will ultimately cost $3.54 billion (including AFUDC).

NU has unsuccessfully sought, since 1981, to reduce its ownership share below the present 65% level. The Council is aware that the Connecticut legislature has taken action designed to "cap" the costs of Millstone 3 at the $3.54 billion estimate,[8] and we expect this action to add to the Companies' existing incentives for timely completion of this project.

NU's other commitment to nuclear units under construction amounts to 46.7 MW in each Seabrook Unit. NU continues to seek to sell its entire ownership in Seabrook. Also, a recent Connecticut DPUC Decision orders the Connecticut Light and Power Company, NU's subsidiary with the entire Seabrook entitlement, "to make every effort to disengage from

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4. Forecast, Vol. II, p.iii.
5. Response to Staff Information Request S-1.
6. See 8 DOMSC 62-147.
7. Millstone Unit No. 3, Quarterly Progress Report, Quarter Ending September 30, 1987, Response to Staff Informatin Request D-4.
8. Northeast Utilities Prospects Supplement, July 18, 1983, p.3, Response to Staff Information Request D-5.

Seabrook Unit No. 2".[9] In light of these events, the Council views Seabrook II as an improbable addition to the System's capacity.

Together, Seabrook I and Millstone 3 represent an additional 794.2 MW of non-fossil capacity coming on-line for NU in the 1980's, and will account for 11.8% of the System's total capacity in 1986. NU projects that these additions will increase the share of total energy requirements met by nuclear from 57% in 1982 to 64.5% in 1987,[10] largely displacing oil. For this reason NU views completing Millstone 3 as the "cornerstone" of its oil reduction program.

Massachusetts ratepayers have a significant interest in seeing the timely and economic completion of Millstone 3, and the Council urges NU and its subsidiaries in the Commonwealth to continue to evaluate the relative economics and oil displacement value of their present ownership shares. We further ask the Companies to inform the Council, in future filings, of any changes in the projected on-line date or final construction cost.

2. Coal Conversions

NU's coal conversion program led to the successful conversion of the 148 MW Mt. Tom unit in Holyoke, Massachusetts in late 1981. Proposed conversions at Norwalk Harbor, Devon Units 7 and 8, and West Springfield would convert an additional 767.3 MW of oil fired capacity to coal, but "substantial uncertainty" surrounds these plans, according to the Companies.[11] The major outstanding issues are uncertainty over environmental equipment costs, coal and oil cost differentials, and the potential for new Federal air quality standards resulting from the national acid rain debate.[12]

In the face of uncertainty on so many fronts, the Council finds the Companies' strategy of undertaking a detailed re-study of the lower cost Norwalk Harbor Conversions to be reasonable. The Council requests that NU provide a summary of the study, scheduled to be completed in mid-1984,[13] with its next filing, and to also update its longer term plans for converting Devon and West Springfield. To the extent that NU can satisfy federal and state environmental standards, while also reducing revenue requirements through its proposed coal conversions, the Council reiterates its past support of these plans.

3. Other Planned or Potential Supply Sources

NU's recent hydroelectric restoration and expansion program has resulted in 22.6 MW of restored or new hydro capacity coming on-line since 1980, including the recently completed Hadley Falls Unit 2 in Holyoke. With these additions the Systems' share of energy provided by hydro is expected to remain at approximately 4%.[14]

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9. Decision, Docket No. 83-03-01, Aug. 22, 1983. p.51.
10. From forecast, Vol. II, p.III-4 for 1982, and response to Staff Information Request p-2 for 1987.
11. Response to Staff Information Request S-8.
12. Ibid.
13. Ibid.
14. Derived from Response to Staff Information Request P-2.

NU also stands to gain significant amounts of capacity and/or energy from the Power Authority of the State of New York (PASNY) and from Hydro-Quebec.

Under a proposed reallocation of hydroelectric power under PASNY's control, Massachusetts may receive 48 MW firm and 8 MW peaking power, and Connecticut may receive 35 MW firm and 5 MW peaking, effective in 1985. NU's share of these amounts remains uncertain, however, until the ultimate allocation scheme is finalized by PASNY.[15]

Along with other New England Utilities, NU is a participant in the Phase I 690 MW interchange with Hydro Quebec. According to provisions outlined in this agreement, NU will receive 23.61% of the benefits accruing to NEPOOL from economy interchange, energy banking, and non-firm energy purchases.[16] The transmission facilities required to effect this exchange are projected to be in place in October, 1986.[17] Phase II negotiations, involving a larger 2000 MW tie with the possibility of capacity purchases, are still underway.

Potential energy and/or capacity from PASNY and Hydro-Quebec are not integrated into NU's overall forecast of supply at this time, presumably due to uncertainty concerning precise PASNY allocations and Hydro-Quebec dispatch. The Council is concerned, particularly with Hydro-Quebec, that a system own-load dispatch for NU will no longer be representative of actual operation or running costs for its planning purposes. In its next forecast, the Council expects to see the operating effects of Hydro-Quebec (and other predictable exchanges of energy and capacity) incorporated into the Companies' planning models and price forecast. Otherwise, the study of other oil-displacing strategies might not reflect their true worth, and the price forecast may not reflect expectations of System revenue requirements. In compliance, NU should fully document the changes to input assumptions or explicit changes to output with its planning and forecasting models. This requirement is set forth in Condition 5.

4. Cogeneration and Small Power Production

During 1982, NU purchased 7,583 MWH from existing customer owned generation,[18] amounting to 0.04% of total system energy requirements. The majority (91%) of this energy originates from small scale hydro facilities along the Connecticut River, with the remainder being derived from one fossil fuel and two biomass facilities.

NU has since lost the contribution of facilities amounting to one-half the 1982 energy supplied, primarily due to a single owner of five hydro units opting for a long-term contract with Fitchburg Gas and

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15. Forecast, Vol. II, p.III-8. The Council has since learned that the allocation scheme has been finalized so we expect subsequent filings will reflect more up-to-date information.
16. Information distributed by NEPOOL and Hydro-Quebec at the Hydro-Quebec signing, March 21, 1983, NEPOOL Participants - Percentage Share of Hydro-Quebec Power Based on Relative Energy Sales 1980.
17. Ibid.
18. Forecast, Vo. II, p.III-11.

Electric Light Co.[19] However, newly signed contracts with a cogenerator and hydro facility are projected to add 95,000 MWH annually beyond 1985.[20] This would increase the share of NU's system requirements supplied by cogeneration and small power from 0.04% to 0.54%.

To increase the contribution of cogeneration and small power to NU's system, the Companies have taken two major steps foreward - the cogeneration study, and the adoption of a flexible floor-pricing policy.

In 1981 NU, through a contractor, conducted a preliminary assessment of the cogeneration potential of the 370 largest Connecticut customers. This assessment indicated an "economically developable potential of about 200 MW of cogeneration."[21] In 1982, NU also sponsored cogeneration seminars in six locations within its service area that were attended by 309 customers.[22] A recently completed more comprehensive analysis concludes that 59-91 MW of potential cogeneration capacity, in both Connecticut and Massachusetts, warrants development.[23] This significant conclusion is based on a survey of 452 large demand customers, from which 260 responded. Of the responses, 118 customers met minimum technical requirements, and 98 of these facilities met internal rate of return criteria.

The Council lauds NU's effort directed at identifying potential cogeneration capacity within its service area. In its next Forecast, we request that NU keep the Council informed of the Companies' follow-up efforts and the status of the designated facilities.

The second important step taken by NU to encourage small power development is the establishment of a floor-price policy that allows for payments to developers greater than avoided costs in the early years to be recovered through lower than avoided cost rates in later years. NU has found that DPU-set short-term avoided cost rates are generally not sufficient to assure project construction and that developers and their financial backers require a long-term stable rate.[24] NU's floor pricing policy is an innovative mechanism that meets both the developer's needs for a guaranteed minimum revenue stream to cover payment of financing costs and the utility's requirements that ratepayers be kept whole in the long-run.

The Council wholeheartedly endorses this pricing mechanism and supports the fact that NU is applying long term economic return criteria

19. See response to Staff Information Request S-4, and Forecast, Vol. II, p.III-11.
20. Forecast, Vol. II, p.v-5.
21. Forecast, Vol. II, p. III-10.
22. Response to Staff Information Request S-3.
23. Cogeneration Potential in Northeast Utilities Service Area: Phase II Investigation, Final Report, Dames and Moore, December 26, 1983, provided to Council Staff by the Companies at the Technical Session on January 22, 1984.
24. Response to Staff Information Request S-7, "Northeast Utilities System Cogeneration and Small Power Production Purchasing Policy", October, 1983.

to cogeneration and small power facilities, akin to how the Company evaluates its own investments. There are, however, other aspects of NU's cogeneration policy that the Council believes warrant further consideration.

The first concern is NU's standards for setting the projected present worth of cogeneration contracts in relation to probable values of future avoided costs. NU's cogeneration contract price terms are determined on the basis of certain probabilities that long term avoided costs - derived from NU's judgements concerning oil price forecasts - will or will not be exceeded. NU requires, for example, that no greater than a 10% probability exists that the payments under a cogeneration contract will exceed 120% of avoided costs, and that no greater than an 80% probability exists that payments will exceed 80% of avoided costs. According to Council Staff's computations, weighing the Companies' probabilities leads to a long term value for expected payments of approximately 87% of avoided costs.[25] This appears to be a significant premium in exchange for offering the developer a long-term contract and incorporating initial rates that exceed avoided costs. The Council feels that NU should more fully develop the basis for selecting its PURPA contract probabilities and indicate whether these same probabilities apply to internal supply investments.

A related concern is NU's requirement that developers post a performance fund that allows NU to recover payments in excess of avoided costs in the event of terminated or unacceptably low generation.[26] The Council appreciates NU's combined efforts to responsibly encourage the development of cogeneration and small power while also protecting ratepayers from undue risk and higher costs. The Council does feel, however, that NU may be requiring cogenerator and small power production developers to take on too great a share of the risk of these contingencies.

In sum, it is not evident that the goals of PURPA and equitable sharing of risk are achieved with a contract that offers long-term expected payments that are, on average, no more than 87% of avoided costs, while also requiring the developer to post funds against initial payments to the extent that they are greater than avoided costs. Therefore, the Company is urged to re-evaluate and justify its contractual policies for small power producers, with particular attention to the combined effect of less-than-avoided-cost payments and performance requirements.

5. Conservation and Load Management

Since the January, 1981 introduction of its 80's/90's Program, NU has gained considerable experience with its conservation programs. Over this period, NU's programs have generally been well received by its customers and other regulatory agencies.[27]

25. Ibid, p.11. From the Companies probabilities, the Staff's weighting calculation is ((120x10) + (100x25) + (85x50) + (80x80))/165 = 86.9% of avoided costs.
26. Ibid, p.11.
27. See MDPU No 1300; and CDPUC No. 83-07-15.

The Council, in its last Decision, favorably reviewed NU's overall conservation program development. Paralleling this approval, we directed the Companies to conduct a cost/benefit analysis of its conservation programs, and to meet with Council staff to develop and appropriate methodology for addressing the Council's specific concerns. 8 DOMSC 146. The DPU included a similar order in its review of WMECo's 1982 proposed rates.[28]

In response, NU staff met with Council and EOER Staff on July 15, 1982, to discuss its proposed cost/benefit methodology, and has further provided an analysis of nine programs in the instant proceedng. This document, Cost Benefit Analyses of Northeast Utilities Customer Conservation Programs, July, 1983, and the aforementioned meeting represent good faith efforts at satisfying our Conditions set forth in EFSC NO. 81-17. We now review NU's 1983 program activities in Massachusetts and the Cost/Benefit Analysis.[29]

Table 2 shows the wide array of programs offered in 1983 to WMECO's customers along with estimated expenditures. The majority of estimated activity and dollars have been earmarked for the Mass Save, Wrap-Up/Seal-Up and Energy Care residential programs, the commercial/industrial audit program, and the streetlighting conversion program. These direct or "service" type programs account for 85% of estimated 1983 expenditures. The other programs are largely "informational" or research oriented. This appears to be a good balance of program emphasis. Estimated expenditures on the programs in Table 2 amount to the modest sum of about one-half a percent of WMECO's total operating revenues.[30] In order to begin assessing the appropriateness of this level of investment, we turn to the Companies cost/benefit analysis.

In its analysis, NU has selected nine programs for study. All of these are offered in Massachusetts with the exception of the low interest loan program. The Companies' methodology incorporates an application of the "no-losers test" in a straightforward manner. This test, simply stated, says that conservation expenditures will benefit non-participating customers as long as the per-unit cost of the conservation program (C) is less than the amount by which long-run marginal costs (MC) exceed long-run average costs (AC):

$$C \leq MC - AC.$$

NU has found, in evaluating these nine programs, that none pass the no-losers test. This is due to the finding that NU's marginal operating costs (principally fuel burned at the margin) do not exceed average costs (fuel and capacity). On a 15 year present value basis, NU estimates that the nine programs (running for 3 years each) will

28. MDPU 957, p.65.
29. NU states that program information for 1984 will be available "on or about March 15, 1984". Northeast Utilities Customer Assistance Conservation Programs, Western Massachusetts Electric Co., December, 1983, p.1.
30. Based on WMECO's 1982 Operating Revenues, Annual Report, 1982, p.7, provided in response to Staff Information Request D-2.

Table 2
NU's Conservation Programs in Massachusetts and Estimated Expenditures for 1983[1]

	Program	Description	Estimated 1983[2]
Residential Programs:	Mass Save	Home energy audits	$485,000
	Wrap-Up/Seal-Up	Delivery of water heater wraps and low-cost weatherization services	345,900
	Energy Care	Information, workshops, and weatherization kits for low-income households	115,300
	100 Plus Dwellings	Promotes energy efficient dwellings, new and retrofit	41,400
	Energy Value plus	Information on appliance purchases and use.	33,700
	Operation Solar	Information on solar technology	15,000
	Conservan	Mobile conservation van to promote residential programs	13,200
	Radio-Controlled Water Heating	Promotes installation	500
Commercial/ Industrial Programs:	Energy Check	Audits	67,500
	Information for Large C/I Customers	Conservation information	8,900
	Energy Value Building	Promotes efficiency in new construction	1,800
	Technical Training Courses	Conservation courses	10,900
Municipal Programs:	Conservation Assistance	Provides an EMS consultant, promotes audits and street-lighting conversion	6,600
	Streetlighting	Provides for conversion to sodium lamps	68,400
Other:	Research, Evaluation, and Admin.		50,800
Total			$1,269,400

1. From Exhibit 4, Northeast Utilities Customer Assistance Conservation Programs, Western Massachusetts Electric Co., December, 1983.
2. Includes estimated direct costs less revenue received plus allocated payroll.

increase revenue requirements by about $97 million. Contrasted with total revenue requirements over the same period, this represents an increase of one-half of one percent.[31]

For the programs studied, NU estimates that its programs in Massachusetts achieve an impressive average cost/benefit ratio of 6.9 to 1. It is clear that participating customers derive significant benefits from these programs.

If we were to strictly adhere to a lowest long-run revenue requirement standard, the Council might recommend the abolition of NU's conservation programs based on the no-loser's test results. Three factors, however, lead us to a contrary conclusion: the need for refinement in the Companies' analysis; the restrictiveness of the no-losers test; and the Council's broader mandate. We discuss each in turn.

The Company's study is generally well documented and a commendable effort in a difficult area of analysis. The overall methodology is sound, but certain inputs and underlying assumptions are in need of refinement. First, the kilowatthour savings attributable to the programs are in some cases well documented engineering estimates, while for other programs they are unsubstantiated or deemed "unquantifiable". The Council understands the difficulty associated with measuring the impacts of some conservation programs but we encourage the Companies to continue to monitor the costs and benefits of these programs.

The Companies' definition of average cost, or foregone base revenues, also needs refinement. NU recognizes that the system average cost used in its analyses "may be over-or understated, depending on the relationship of class average revenue to total company average revenue". In the Council's view, not only should class average cost be considered, but more specifically, we see the class "average cost" at the margin as the appropriate measure of foregone base revenues as long as the Companies' rates exhibit declining block characteristics. For example, a residential customer using 500 Kwh per month in WMECo's service area would currently pay a rate of $34.21, for an average 6.8 cents/Kwh, plus a flat fuel charge. A conserved kilowatthour, however, would only result in a base revenue loss of 5.8 cents in this first block. For a conserved kilowatthour by an electric heating customer, or

31. Calculated from Cost/Benefit Analysis, p.39, provided under cover of September 30, 1983, and Response to Staff Information Request CLM-4.

others using over 500 Kwh per month, the base revenue loss is only 4.286 cents.[33] The differences between average class revenue and "average cost" at the margin are more pronounced in the general service rate schedules with steeper declining blocks.[34] In sum, the more the Companies' fixed costs are recovered in initial blocks or through a fixed customer charge, the lesser the fixed cost losses attributable to conservation at the margin. Each program should therefore be assessed with the applicable "average cost".

Lastly, on refinement, the Companies' analysis assumes a zero value for unused capacity and for unused transmission and distribution (T&D). The capacity value of conservation to a system with excess, such as NU's, is less obvious than that for a system facing immediate expansion. NU has indicated elsewhere, however, that it actively promotes off-system sales.[35] To the extent that conserved energy and capacity can be marketed off-system, this should be reflected in the analysis. Similarly, while the Companies reflect uncertainty as to the appropriate value of conservation to its T&D system, such a benefit is recognized in its Cogeneration and Small Power Producer rates.[36] Given the Companies' present analysis, that indicates its conservation programs may result in increased rates of only $.0005 to $.001 per kilowatthour,[37] recognition of even very small "fixed cost" benefits may affect the Companies' results.

On the appropriate test for evaluating conservation programs, the Council has not thusfar announced a specific policy. The programs we have reviewed to date have been largely experimental and research oriented without supporting cost/benefit analyses. NU's progress to date in implementing and evaluating its programs presents an appropriate time for the annunciation of Council policy in response.

The Council does not adhere to the tenet that conservation programs must pass the no-losers test, as long as other guidelines are met. We are cognizant that ratemaking, by practical necessity, contains certain inevitable inequities.[38] The indication of subsidization by non-participating customers, in and of itself, should not thwart a conservation program. It does, however, indicate the need for even more careful program development.

It is the Council's position that a utility's conservation programs should meet the following guidelines:

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33. WMECo Residential Schedule 10, MDPU No. 491, Effective July 5, 1983. Customer charge of $5.21 plus 500 Kwh times 5.8 cents.
34. Small General Service Schedule 20, MDPU 492.
35. See Response to Staff Information Request S-1.
36. See Response to Staff Information Request CLM-5.
37. See Cost/Benefit Analysis, p.5.
38. For example, remote electric customer with higher transmission and distribution requirements pay the same customer charges as a company's more urban customers. New customers who cause the construction of the newest and highest cost plant pay the same rates as existing customers.

1. Individual or groups of programs, should be designed so that the customers who bear the costs of the program have, to the largest extent possible, an opportunity to participate.

2. Programs offering the greatest, long-run savings to participants, per utility dollar spent, should be emphasized.

3. Programs should be targeted to the utility's submarkets that, due to lack of information or capital, might not otherwise enact these conservation measures.

4. Programs should target the conservation of the utility's product (electricity or gas) over other fuels.

The first guideline addresses equity between customer groups, without the imposition of the uneccessarily restrictive no-losers test. The second guideline addresses the cost-effective use of the utility's and participants' capital. The third guideline addresses market imperfections, a situation in which a utility is in a unique position to act effectively. The last guideline recognizes that a utility operates most effectively where its own product is concerned.

The Council feels that these guidelines properly balance the issue of inter-customer subsidization with those of federal and state energy policies, and the Council's mandate to "provide a necessary power supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost" MGL Ch. 164, sec. 69H. Conservation is probably the most environmentally benign energy resource at a utility's disposal, and although the externalities associated with conventional supply sources have not been quantified in this record, the Council finds the small premium indicated for NU's conservation programs to be within reasonable bounds.

Finally, to ensure NU's continued progress in evaluating its investments in conservation, the Council requires the Companies to submit a refined analysis with its next filing. Condition 6 incoporates this requirement.

D. Summary of Findings on Supply

1. NU has existing and planned capacity that is more than sufficient to meet forecast load and reserve requirements.

2. NU should continue to evaluate its capacity requirements and aggressively negotiate sales contracts for its near term excess capacity.

3. The Companies' strategy of undertaking a detailed re-study of the Norwalk Harbor coal conversions is a reasonable response to present circumstances.

4. The Companies' cogeneration study and floor-pricing policy are positive first steps toward encouraging small power production.

5. NU should not require more risk and cost protection from small power production than is required of the Companies' investments.

Preliminary indications are that:

6. NU's customer conservation programs do not pass the "no-losers test", but nonetheless offer significant benefits to participants.

7. The Companies' cost/benefit analysis of conservation programs needs refinement.

VI. DECISION AND ORDER

It is hereby ORDERED that, given the points and considerations set out in the foregoing analysis, the 1983 Annual Supplement of the Northeast Utilities System is APPROVED subject to the following Conditions:

1. The Forecast documentation shall be expanded to comply with EFSC Rules 63.5 and 69.3. Council staff shall meet with Company staff within 60 days to clarify how the Company might comply with this and other conditions.

2. The Companies shall re-evaluate its short-term housing stock model and further substantiate the basis for deriving service-area customer and employment forecasts from state-wide forecasts.

3. Price effects shall be explicitly incorporated into the Companies' long-run forecasting models and suitably documented.

4. The results of the Companies' experimentation with forecasting industrial sales on a disaggregated basis, and the Companies investigation into its conservation, technological change and building standards assumption shall be provided to the Council.

5. NU shall incorporate in its planning models and price forecast and fully document, the operating effects of PASNY, Hydro-Quebec, and other predictable exchanges of energy and capacity.

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

Lawrence W. Plitch, Esq.
Hearings Officer

Unanimously APPROVED by the Energy Facilities Siting Council on April 30, 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); Charles DeSaillan (for James S. Hoyte, Secretary of Environmental Affairs); Joellen D'Esti (for Evelyn F. Murphy, Secretary of Environmental Affairs); Ineligible to vote: Dennis J. LaCroix (Public Gas Member).

May 14, 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 & Electric Light Company for Approval of the First Supplement to the Second Long-Range Forecast of Electric Needs and Requirements	)	Docket No. 83-11

FINAL DECISION

James G. White, Jr.
Hearing Officer

On the Decision

William Febiger
Staff Analyst

April 30, 1984

TABLE OF CONTENTS

The Energy Facilities Siting Council ("Siting Council") hereby APPROVES the First Supplement to the Second Long-Range Forecast of Electric Needs and Requirements of the Fitchburg Gas and Electric Light Company ("Fitchburg" or "the Company") subject to the CONDITIONS set forth herein.[1]

I. Background and Procedural History

Fitchburg is an electric company within the jurisdiction of the Siting Council. Mass. Gen. Laws Ann., ch. 164, sec. 69G. Fitchburg is an investor-owned utility which provides electric service to the City of Fitchburg and the Towns of Ashby, Townsend and Lunenburg. Fitchburg filed the current Supplement on April 15, 1983, and provided public notice of the filing through publication and posting of the Notice of Adjudication. The Siting Council received no intervention petitions. Fitchburg filed responses to one set of information requests, and later filed updated responses to several information requests involving electricity supply.

II. Prior Conditions

In its decision involving Fitchburg's Second Long-Range Forecast, the Siting Council attached four conditions 7 DOMSC 238, 241 (1982). Two of the conditions involved the demand portion of the Forecast. Previous Condition 2 provided:

> That documentation of industrial survey data shall be provided in the next EFSC filing. This includes providing verification of all judgements and supporting documentation, which can be provided without violating the confidentiality of the industries surveyed.

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1. The Energy Facilities Siting Council has employed the same review criteria herein as in past decisions. Fitchburg Gas & Electric Light Co., 7 DOMSC 238, 241 (1983).

As discussed herein, the Siting Council finds that Fitchburg has not complied with this condition. Fitchburg's industrial documentation continues to be inadequate, and a condition is included requiring development of a more reviewable industrial model. See Section III-C, infra.

Previous Condition 3 provided:

> That the Company actively endeavor to collect and analyze territory and sector specific data, particularly with respect to the demand forecasting methodology for the residential sector. Further, data which assesses the conservation potential and impact, by sectors should be documented. Given the Company's limited resources, the Council recommends that the company develop a long-term data collection plan and implement it in planned, low-cost phases.

In the current Supplement, the Company has incorporated data from its residential audit program, but has not established a program or demonstrated a commitment for long term data collection. Accordingly, the Council reasserts its recommendation for development of a long term data collection plan. In addition, the Council suggests that the Company consider development of econometric models to more expeditiously meet the Council's concerns for reviewability and reliability. See Section III-A, infra.

The Council's last decision contained two supply conditions. Condition 1 provided:

> [T]hat the Company develop comprehensive supply plans to be implemented in the event that; (1) the 40 MW Boston Edison supply contract is not offered or renewed by BECo, or not accepted by the Company; (2) the start-up of Seabrook Unit No. 1 is delayed until power-year 1985/86; (3) Seabrook Unit No. 2 is delayed until 1988; (4) Seabrook Unit No. 2 is not in service at any time during the forecast period. ...This shall be presented to the Council within 60 days.

In response to this Condition, the Company on April 17, and April 20, 1982 provided additional written and oral information regarding its supply plan including an indication that an extension of the 40 MW contract with Boston Edison Company ("Boston Edison" or "BECo") would be finalized in the near future. The Council concluded that the additional information was an adequate response to the Council's concern regarding the supply plan, that the contract extension was viable, and that the Company was taking the steps necessary with Boston Edison to insure viability.[2] While, Fitchburg complied in 1982 with Condition 1, the Siting Council's concerns as discussed *infra*, about Fitchburg's supply plan, particularly the lack of an extension or replacement of the Boston Edison contract, are more pressing than ever.

Previous Condition 4 provided:

> That the Company continue to encourage development of all cost-effective low-head hydro sites and to actively and aggressively support development of cogeneration and other small power producers. ...

The Company has signed contracts with two hydropower developers and studied cogeneration potential with two large paper firms. As to Condition 4, the Council commends the Company's progress. The Council believes the Company should continue its efforts and, where appropriate, consider new approaches to encourage greater response from small power producers. See Section IV-C-6, *infra*.

2. See letter dated May 13, 1982, from Siting Council Chairperson Margaret N. St.Clair to Fitchburg's President, H.W. Evirs, Jr. In the current Supplement, Fitchburg states that Condition 1 to the previous Decision "was responded to adequately in April 1982" as evidenced by the letter from Chairperson St. Clair. The letter expressly stated, however, that "[t]his does not constitute an adjudication of the merits of Fitchburg Electric's supply plan." Docket No. 81-11.

III. Review of the Demand Forecast

Fitchburg has projected total electrical energy requirements for its system to grow from 362,300 megawatthours (MWH) in 1982 to 483,600 MWH in 1992; a 2.93% equivalent annual compound growth rate. The industrial class, which accounts for over half of system sales, leads all classes with a forecasted annual compound growth rate of 4.33%. Fitchburg has projected the summer peak system load to grow from 61.7 megawatts (MW) in 1982 to 87.7 MW in 1992; a 3.58% equivalent annual compound growth rate. The shares of system sales and forecast period annual growth rates are shown by class in Table 1.

Table 1
Relative Sizes and Annual Growth Rates By Customer Class

Class	Percent Change, 1982-92	Percent Of System Sales, 1982
Residential:		
Electric Heat	1.20	2.11
Without Electric Heat	0.34	27.55
Commercial	1.61	12.42
Industrial	4.33	56.91
Street Lighting	-0.61	1.01
Total Sales	2.92	100.00
Total Requirements	2.93	-

A. Residential

Fitchburg forecasts residential electricity demand by adjusting actual sales data from a base year to account for anticipated changes in consumption over the forecast period. In this Supplement, the Company used 1982 as its base year. Actual 1982 sales were adjusted to account for "normal growth" (historical growth in use-per-meter), new construction, and the impacts of energy-efficient replacement appliances, audit-stimulated conservation, and new wood stoves. The Company forecasts that new customers will consume over 25 percent less electricity per meter than existing customers.

Fitchburg's forecast of new construction is based on 1977 service territory population projections from the Montachusett Regional Planning Commission and the Fitchburg Planning Office, adjusted to accommodate 1980 Census data. The Company anticipates an average annual increase of 100 homes per year, the bulk of which will be in one and two person households.

The Council questions the continued applicability of the seven-year old population study, especially now that 1980 Census figures have been available for some time. Although the Company adjusted the 1977 data for consistency with the 1980 Census data, the Council is concerned with the magnitude of these adjustments. The Siting Council requests the Company to provide more information to support the adjustment methodology and the adjusted data, and to describe the efforts and plans of the local planning agencies to update the 1977 data in future filings.

The Company has for the first time integrated estimates of potential savings identified in energy audits into its residential forecast -- a positive step in the Council's view. Fitchburg estimated savings of 15 Mwh per year in the non-electric heat class and 42 Mwh per year to electric heat customers. (Supplement, Appendix AC).

The Council remains concerned with the quality of appliance data utilized by the Company to calculate reductions in consumption from 1982 levels due to energy-efficient replacement appliances. In its previous Decision, the Council recognized the Company's appliance saturation study which was based on a sample of customers who visited the Fitchburg Gas and Electric booth at the Fitchburg Home Show. 7 DOMSC 238, 244. However, the Council urged the Company to improve upon the quality of its data in this area, and recommended that the Company develop a long-term data collection plan. In the present filing, the Company has incorporated revised Edison Electric Institute usage levels and replacement rates for appliances. However, the Company neither responded to the Council's concerns about data reliability nor presented a data collection plan.

With regard to replacement rates, downward adjustments of 20 percent were made for a number of appliances, apparently based on the poor economy and/or possible appliance upgrading by customers. The Company suggested that savings from replacements are "hard to predict as evidenced by the increase in residential load in 1982 from 1981." Supplement at 10. The Siting Council believes that the Company's difficulty in estimating the effect of appliance replacement points out the need for better information on customer activity with regard to replacements, and for consideration of other causal factors, such as trends in electricity prices.

Fitchburg has adjusted its residential forecast to account for its estimate of the electricity required to charge batteries for electric cars in its service territory. This allowance was reduced by more than 50% from that made in the Company's previous forecast, to 2.9 MW, but still represents 71% of the 4.1 MW increase in total residential sales over the forecast period. Other than the Electric Power Research Institute Study, which was also cited in the 1981 Forecast, the Company provides no evidence supporting this allowance or any adjustment to it.

Additionally, the Company does not discuss or analyze the impact on electric cars of trends in the relative prices of competing forms of energy.

The Company's efforts in the areas of appliance efficiency and electric vehicles illustrate significant problems that apparently exist in the overall forecast methodology. The overall approach depends on a collection of judgements that are difficult to substantiate, and lacks references to the causal factors (other than population growth) that drive residential demand. For example, the price of electricity is an underlying causal factor that is important in the prediction of appliance usage and electric vehicles, but has not been considered in the Company's projections. Price of electricity is likely to be significant in the Company's projection of "normal growth" in the average electricity use per residential customers as well.

The Council believes that the Company should consider econometric modeling as an expeditious means of addressing the Council's concerns about reviewability and reliability. The Council notes that the Taunton Municipal Light Plant, a utility of approximately Fitchburg's size, recently began to forecast demand using econometrics (10 DOMSC 252 (1984). The Council observes that an econometric model would provide a basic framework for forecasting, but would not negate the need for and significance of the analyses in the Company's current forecast. These would continue to be important for verification and for selective adjustments to the model. Analyses of appliance use would of course also remain important for pursuit of conservation-load management as a supply planning option. See *infra* Sec. V-D. Additionally, the Company still would need to develop and implement a plan for collection of customer use data. The Company, however, could be more selective and focused toward its conservation-load management program objectives.

Therefore, as a CONDITION for approval of its 1983 Supplement, the Council hereby ORDERS the Company to review its residential forecast methodology and related data collection needs in light of this and previous Council Decisions. The Council ORDERS the Company to consider alternative approaches including use of econometric models, and to develop a plan for addressing Council concerns regarding reviewability and reliability in an expeditious and cost-effective way. The Company shall submit a preliminary compliance plan within 90 days, and shall include a detailed compliance plan in its next filing. The Council Staff is available to meet with the Company to discuss Compliance with this Condition, affixed hereto as part of Condition 1.

B. Commercial

The Company's commercial forecast, which includes municipal housing units, is based on separate allowances for new development and normal growth in existing customer usage, added directly to 1982 actual data. Expected sales to new commercial and small municipal entities were based on information from interviews. Fitchburg added these additions to the anticipated normal growth in commercial sales to existing customers, which were estimated at 300,588 Kwh/year based on past levels of commercial energy per residential meter and population projections of the Montachusett Regional Planning Commission adjusted by 1980 Census data.

With regard to expected new or expanded commercial establishments, the interview method identified expected additions in only the first two years of the forecast period. The Siting Council questions the reliability of this methodology. The methodology appears either not to capture growth in the later years of the forecast period, or to be optimistic in the timing of the growth that it does capture. The interview method also is inherently limited in its reviewability, as the interviews reflect collective intentions in the past not linked to any identifiable common assumptions about regional economic growth or commercial needs.

The Council recognizes that Fitchburg's Commercial class is small, and that the "normal growth" component of the forecast is in fact based on a reviewable statistical method. As indicated above, however, there are areas for improvement in the commercial methodology. Given the Council's mandate to the Company to review its residential methodology, the Council believes the Company should make a concurrent review of the commercial methodology. Therefore, as a CONDITION for approval of its 1983 Supplement, the Council hereby ORDERS the Company to review its commercial forecast methodology and related data collection needs in light of this and previous Council Decisions. As in the case of the residential methodology, the Council ORDERS the Company to consider alternative approaches including use of econometric models, and to develop a plan for addressing Council concerns regarding reviewability and reliability in an expeditious and cost-effective way. The Company shall submit a preliminary compliance plan within 90 days, and shall include a detailed compliance plan in its next filing. The Council Staff is available to meet with the Company to discuss compliance with this condition, affixed hereto as part of Condition 1.

C. Industrial

Nearly 60% of Fitchburg's sales are to industrial customers. The Company based its forecast of future industrial sales on projections of normal growth in sales to existing customers, specific estimated increases in industrial load, and additional requirements for projected development of the Montachusett Industrial Park, the 231 Industrial Park and the planned Hotel Complex near the intersection of Routes 2 and 31 in West Fitchburg. The Company compiled this information through interviews with its industrial customers and local planning boards.

The Council has expressed its concerns with the subjective nature of the Company's interview-based methodology in the past and continues to express them here. As discussed in this Section and generally acknowledged by the Company, industrial sales appear to be strongly affected by macroeconomic fluctuations. In order to meet the Council's standards, the forecast methodology should provide a consistent and reviewable set of assumptions concerning macroeconomic variables, such as Gross National Product.

The Company's industrial consumption has declined at an increasing rate since 1979. Fifty percent of the Company's industrial load is composed of paper industry customers. The Company attributed its loss of load to their depressed condition and forecasted an 8% annual sales increase for both 1983 and 1984 based on expectations of economic recovery. These increases, and the 4.3% average annual compound rate of industrial sales increases for the overall 1982-92 Forecast period, are significantly higher than available projections for relevant state and national economic indicators.[3]

3. See e.g., Bank of Boston The Economic Outlook for the Tri-City Area in Southeastern Massachusetts: New Bedford, Fall River and Taunton (October, 1983), which projects an average annual compound increase of 2.54% in manufacturing employment for Massachusetts from second quarter, 1983 to fourth quarter, 1985. Also, the deflated Gross National Product, as reflected in other 1983 Forecasts has been projected to increase at 2.9% annually through 1992. See Taunton Municipal Light Plant (Docket No. 83-51); East. Util. Assoc. (Docket No. 83-33).

The sharpness of the expected 1982-84 recovery, taken together with the 12% 1981-82 decline, might be attributed to a relative sensitivity of Fitchburg's industries to cylical fluctuations in the economy.[4] In addition, Fitchburg noted that its large paper industry customer, James River-Massachusetts, recently converted its process boiler from oil to coal and now expects to be more competitive. However, it is the Council's view that other factors, such as permanent loss of market share, permanent plant streamlining and efficiency measures, and plant closings or relocations, must be systematically reviewed to evaluate the trends in the load requirements of Fitchburg's paper and other industrial customers.

In addition to its expectations of recovery for its recession impacted customers, the Company expects considerable new development in the service territory. The Company submitted a Fitchburg Industrial Development Commission Report (Supplement Appendix O) and a large number of optimistic newspaper articles (Supplement Appendix AB) in support of its projections. The Council believes something firmer than developer press releases and similar materials is necessary to support the Company's assertions of the rate at which the area's new industrial parks will be filled.

Both new growth and sales to existing industrial customers are a function of macroeconomic variables. In response to a staff request for information on the Company's macroeconomic modeling methodology, Fitchburg replied:

> "The economy as a whole is incorporated into the Company's forecast to the extent that it affects residential development and

4. The average annual compound growth rate for 1981-92, largely spanning the 1982 recession, would be 2.7%, which is significantly lower than the 1982-92 rate of 4.3%.

> what the developers tell us they expect to do and when and what the commerical developers do and what our customers tell us about load expansion or cutbacks, all of which are incorporated into the forecast."

The lack of precision indicated in the above response is exactly what gives the Council cause for concern regarding the industrial forecast. The Council does not doubt that the Company knows its service territory and customers well. However, the Council must question the reliability of a forecast that incorporates perceived prospects for economic recovery and growth in the absence of any consistent and explicit consideration or documentation of regional and national trends. The Council believes that the Company should consider econometric modeling as an expeditious means of addressing the Council's concerns about reviewability and reliability. With a statistically-based model as the starting point, the Company could work selectively to make any supportable adjustments based on knowledge of its service area and customers. Therefore, as a CONDITION for approval of its 1983 Supplement, the Council hereby ORDERS Fitchburg to begin development of a reviewable industrial forecast methodology which includes a consideration of macroeconomic variables. The Company shall submit a preliminary compliance plan within 90 days, and shall provide a detailed compliance plan and report its progress in its next filing. The Council Staff is available to meet with the Company on request to discuss the requirements of this Condition, affixed hereto as Condition 2.

IV. Review of the Supply Plan

The adequacy of Fitchburg's supply plan is a serious issue over much of the forecast period. Of primary concern, is the apparently dire need of the Company to extend or modify in some form its 40 MW power purchase contract with Boston Edison beyond 1986, or to present a clear, reliable and economic alternative to this BECo entitlement. While Fitchburg has indicated an intent to have a new contract with Boston Edison signed by the end of 1984, the Siting Council cannot view this development with certainty. Of secondary concern are changes and uncertainties concerning 22.5 MW of planned nuclear capacity included by the Company in its supply plan. Prospects for cancellation of Seabrook 2 have increased, and the Company now supports cancellation. The loss of Fitchburg's 9.9 MW share of Seabrook 2, along with possible delays in completing other units,[5] would complicate the Company's efforts to meet a projected increase of about 25 MW in its NEPOOL responsibility over the forecast period.

A. Existing Supplies

As of 1983, Fitchburg's supply plan includes 48.7 MW of owned generating capability and 46.7 MW of capacity purchases. Table 2 summarizes existing capabilities as well as the amounts of energy generated or purchased from each source in 1982. As indicated in Table 2, the Boston Edison contract currently represents 41.9% of Fitchburg's long term capability, yet provided 65.8% of the energy from long term sources in 1982, thus underscoring the importance of the Boston Edison contract to Fitchburg's supply plan. By contrast, Unit 7, which

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5. The entire Seabrook Project was placed under a work stoppage by Public Service Company of New Hampshire April 18, 1984, raising questions about the timing and reliability of Seabrook 1 as well. Boston Globe, April 19, 1984, P.1.

represents over 25% of Fitchburg's capability, was only ocassionally called into service and provided 0.4% of energy from long term sources in 1982.

Fitchburg also made significant purchases under short term contracts in 1982, totaling 56,400 Mwh from four sources. Approximately matching these purchases was a 57,961 Mwh excess of NEPEX power delivered by Fitchburg above NEPEX power received by Fitchburg.

B. Supply Plan Deficiencies

Table 3 compares Fitchburg's capabilities and summer peak requirements, including allowances for 1985-1992 reserve requirements based on regional factors that NEPOOL uses for planning purposes.[6] Entitlements included in the original filing but now recognized by the Company as uncertain (including Seabrook 2 and the extension without modification of the BECo contract) are omitted. Table 3 also omits a provision for "miscellaneous purchases" included in the original filing. These purchases cannot be found as reliable by the Council, and are thus omitted.

Table 3 clearly shows the Company's considerable deficiencies from 1987 through the end of the forecast period. The Council notes that Table 3 reflects only winter ratings for system capacity, as used in the Company's Supply analysis. The summer ratings for Fitchburg entitlements are 5.7 MW lower, and should not be overlooked in the Company's season-specific supply planning.

6. Company-specific reserve requirements on which Fitchburg's NEPOOL capacity responsibilities actually will be based may differ from the regional factors. Reserve requirements may increase in 1986 and 1987 as new nuclear units come on line.

Table 2

Existing Capacity and 1982 Energy
By Source

Source	Capacity (MW)	1982 Energy ('000 Mwh)
New Haven Harbor (NU)	20.1[1]	99.7
Wyman 4 (CMP)	1.1[1]	2.1
Fitchburg 7	27.5[1]	1.3
Boston Edison	40.0	238.7
Maine Electric	3.1	13.5
Linweave (hydro)	3.1	5.9[2]
Mass. Hydro Assoc.	.5	1.8[3]
Total Long Term Sources	95.4	363.0
Short Term Variable Purchases		56.4
James River (Cogeneration)		1.5
NEPEX Delivered - (98.0)		
NEPEX Received - 40.0		
Net NEPEX		(58.0)
Total Energy		362.9

1. Ownership or Lease
2. April to December
3. August to December

Source: 1982 Return to the DPU

C. Supply Planning Options

Fitchburg has indentified a number of supply options to help make up deficiencies recognized in the course of this proceeding. Clearly the most important supply option is to continue to purchase power from Boston Edison. Other current options are discussed below, including participation in regional hydropower projects, conversion of the Company's combustion turbine to combined cycle operation, addition of an expander turbine at Fitchburg's gas pipeline reducing station, purchase of power from the Fibrex coal-fired cogeneration plant, and purchase of one or more unit contracts for intermediate oil and possible base load capacity. The Company also reports it has undertaken additional analyses and discussions relating to a number of cogeneration and renewables projects, although no further projects appear to be under active consideration at this time.

1. Regional Hydro Projects

Under recent NEPOOL support agreements, Fitchburg is entitled to 3.2 MW of the Phase I transmission capacity for imported 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. Fitchburg is also interested in Phase II of Hydro Quebec, which may provide additional energy and/or capacity beginning in the 1990's.

In conjunction with other Massachusetts utilities, Fitchburg is pursuing 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). PASNY recently issued a plan for post-1985 allocations of power that ultimately would provide

Table 3

Comparison of Long-Term Capability and Estimated Capacity Responsibility, 1985-92

	83	84	85	86	87	88	89	90	91	92
Peak Load	67.2	71.0	73.4	75.2	77.0	79.4	81.8	83.8	85.8	87.7
Per Cent Reserve[1]	-	-	20	21	22	21	21	21	21	21
Cap. Responsibility[1]-	-	-	88.1	91.0	93.9	96.1	99.0	101.4	103.8	106.1
Own Generation	48.7	48.7	48.7	51.2[2]	61.2[3]	61.2	61.2	61.2	61.2	61.2
Capacity Purchases	46.7	46.7	46.2	43.1	3.1	3.1	3.1	3.1	3.1	3.1
Long Term Capability	95.4	95.4	94.9	94.3	64.3	64.3	64.3	64.3	64.3	64.3
Surplus (Deficit)	-	-	6.8	3.3	(29.6)	(31.8)	(34.7)	(37.1)	(39.5)	(41.8)

1. Based on NEPOOL's regional factors. Utility-specific reserve requirements for Fitchburg may differ.
2. 2.5 MW share of Millstone 3 on line.
3. 10.0 MW share of Seabrook 1 on line. See also n.5, *supra*.

about 34 MW to Massachusetts utilities,[7] of which Fitchburg's share would be about 0.3 MW.[8] However, the PASNY plan provides for an initial Massachusetts allocation in 1985 of only 5 MW, with phased increases to 34 MW by 1994. Further, at least one affected state plans to appeal the PASNY plan.

In summary, Fitchburg appears likely to obtain from regional hydro projects 0.1 MW in 1986, 3.3 MW in 1987, with a gradual increase to 3.5 MW by the end of the forecast period. However, the 3.2 MW interest in Phase I Hydro-Quebec does not insure capacity credit, and hence cannot serve to satisfy the Council's requirement for a reliable power supply.

2. Conversion of Unit 7 to Combined Cycle

The Company has analyzed the option of adding a 10 MW generator to its Unit 7 Combustion Turbine for combined cycle operation. The cost was last estimated in 1977 at $4.3 million, or $430 per Kw. However, Fitchburg does not view the option as one that would provide needed base load capacity or reduce its oil dependence, and thus has not pursued it. The Company implies that it considers the project to be a back-up option, which "would be implemented as the lowest cost option or perhaps the only option if required." The implementation lead time is estimated at 3-5 years. Information Return S-11.

While analysis of the Unit 7 combined cycle option evidently has been based on use of oil, the Company indicated that it also has studied options for joint cogeneration facilites with paper company customers

7. Electric Utility Week, February 6, 1984.
8. The allocations in Massachusetts are based on number of 1981 residential class customers. See Power Authority of the State of New York, 1985 Neighboring State Hydroelectric Allocation Plan Proceeding, Recommended Decision by Presiding Examiner Edward L. Block.

using various fuels. One outcome has been a suggestion for further investigation of a joint cogeneration plant with Fitchburg Paper Company, based on use of interruptible gas in the Unit 7 combustion turbine. The option has not been pursued due to Fitchburg's view that no large supply of gas is available. Supplement at 6. The Council recognizes that prospects for gas supplies are uncertain, but notes that the Company should be prepared to evaluate options based on use of natural gas to the extent that future supplies warrant.

In light of the Company's uncertain commitment and the estimated lead time for implementation of the combined cycle conversion, it is unlikely that the option could be available to meet possible deficiencies before 1988. The significance of a further one or two year delay in the first available on-line date is unclear (See <u>infra</u> sec. IV-C-7). Nevertheless, the Company should be active in pursuing its options for developing economic supplies at the Unit 7 facility. The Council expects as part of this effort, for the Company to give adequate consideration to alternative fuels, and possibilities for cogeneration and interchangeable fuel use.

3. <u>Expander Unit</u>

A preliminary analysis was made in 1981 on installation of a 611 KW expander turbine at Fitchburg's gas pipeline reducing station. The project was estimated to cost $1.2 million or nearly $2000 per Kw. Costs in the vicinity of $2000 per Kw are not uncommon for low-operating-cost projects being implemented in the Northeast, for example new and restored hydropower projects. The Company is requested to review its cost estimate, identify any operating cost implications, and provide an update in its next filing on the economics of the option relative to typical small power opportunities of comparable size.

4. Fibrex Coal-Fired Plant

Fitchburg has begun contract negotiations for a long-term purchase of 9 Mw of capacity from the Fibrex plant under construction in Ware, Massachusetts. See Information Return S-3, updated. Fitchburg is seeking a capacity contract beginning in November 1986, but has indicated a willingness to negotiate an avoided-cost contract if the unit is on-line before then, as now expected. Fitchburg also has expressed interest in an additional 13 MW of coal-fired capacity that may be developed by Fibrex at the same site.

Although the costs of the project must be carefully evaluated, it appears to offer Fitchburg the benefit of fuel and unit diversity. The Council supports Fitchburg's efforts to pursue the most economic options capable of both diversifying its supply plan and meeting identified capacity deficiencies.

5. Unit Capacity Contracts

Fitchburg has reported discussions with Northeast Utilities ("NU") and New England Power Company ("NEPCo"), as well as BECo, concerning its need for long term capacity purchase contracts to replace the BECo contract that expires in October 1986. Discussions with BECo have indicated that Pilgrim I capacity included in the current contract will no longer be made available, but that 30-40 MW of oil-fired, and prospectively coal-fired, capacity would be available through about 1990. NU and NEPCo also have indicated availabilities of oil-based capacity through the mid 1990's. NU has apparently made an offer to Fitchburg of capacity from its Montville 6 unit. Fitchburg, however, has not indicated the possible amounts available from NU and NEPCo.

The Company is evidently concerned about the prospect of a further increase in its 75% dependence on oil which could result from replacement of the current BECo contract with predominantly oil-based contracts. In the course of its preliminary discussions with NU and NEPCo, Fitchburg thus requested evaluation of non-oil based increments as part of any prospective contracts. As of March 14, 1984, Fitchburg reported that these discussions are continuing. See Information Return S-3, updated.

The Council supports the Company's efforts to avoid any further increases in oil dependency, and recognizes that the Company may need to assume higher costs initially in order to maintain and improve system diversity and to attain a supply mix capable of long term benefits over oil. Fitchburg's ultimate needs in the area of system diversification, however, appear to be great enough to merit a comprehensive approach, including consideration of all forms of participation in renewables, cogeneration and interchangeable fuel use. With regard to the Company's specific negotiations with NU, NEPCo and BECo, the Council must require the Company to balance its pursuit of diversification with its obligation to timely provide a reliable, least-cost supply plan for all years in the current forecast period. The Company has indicated a commitment to have the successor contract to the present BECo contract executed prior to the end of 1984. See Information Return S-9, updated. The Council expects the Company to meet this commitment (or to demonstrate a totally reliable and economic alternative), and is placing reporting requirements on the Company to monitor progress. See Sec. IV-C-7, _infra_.

6. Renewables and Cogeneration

The Company has been active in signing two hydropower contracts and studying cogeneration potential in conjunction with two large industrial customers. As of summer 1982, a total 3.6 MW of capacity has been under contract from two hydro projects on major rivers outside Fitchburg's territory. The 0.5 MW Massachusetts Hydro Associates contract expires in 1984, while the 3.1 MW Linweave contract continues through 1992.

Additional prospects studied in the Fitchburg area include two projects that could potentially generate electricity and/or produce steam for use by paper companies. In one case, the Company participated with James River-Massachusetts, the Fitchburg Paper Company, and the State Energy Office in a study of a new cogeneration plant at James River. The prospective economic benefits of the project were diminished when James River converted its process burners to coal. The study recommended alternatively that conversion of Fitchburg's Unit 7 facility to cogenerate steam for Fitchburg Paper Company utilizing interruptible gas should be investigated. See Sec. IV-C-2, *supra*. In addition, the City of Fitchburg has pursued a possible refuse burning plant that would generate electricity for the Company and produce steam for James River. The project does not appear to be economic without the steam sales, however, and no acceptable site with adequate proximity to James River has been found.

The Council commends the Company's efforts to obtain capacity as well as energy from renewable resources, and to investigate major process-related cogeneration opportunities provided by Fitchburg's biggest industries. The Council encourages the Company to continue and broaden its efforts, and to include consideration of state-of-the art approaches for encouraging greater response from small power producers.

For small power producers generally, a broader program would include efforts to encourage both firm and non-firm capacity. While it is recognized that Fitchburg needs capacity, energy from non-firm as well as firm sources can provide long term economic benefits through diversity. As one method of encouraging more small power contracts, the Council suggests that Fitchburg consider instituting contractual policies that include minimum-floor-pricing opportunities under appropriate circumstances.

In the particular area of cogeneration, a broader program might extend beyond the major process industries to include smaller industrial, commercial and institutional concerns with sizable thermal requirements. Pre-packaged cogeneration units in the 50-150 KW range and costing under $1000 per Kw are increasingly available and prospectively an important part of the industry.[9] The Company should be more agressive in identifying the thermal-based potential for cogeneration in its service territory, and in promoting and assisting its development.

7. Summary and Conclusions

Table 4 summarizes the specific capacity options by year based on information provided by the Company, and compares them to the capacity deficiencies identified in Table 3. Over the forecast period, assuming inclusion of all identified capacity options, Fitchburg would have sufficient capacity through 1990 and be about 3.5 and 5.8 MW short in 1991 and 1992 respectively. However, deletion of the 13 MW additional Fibrex capacity, which appears to be the most speculative of the

9. See Energy User News, "Pre-Packaged Cogeneration Units Now Available for Small Users", December 12, 1983.

specific options presented, would leave a deficiency of 18.8 MW in 1992. Deletion of both the additional Fibrex and the Unit 7 conversion to combined cycle, which the Company does not appear to be actively pursuing or supporting, would leave a deficiency of 28.8 MW in 1992.

The Company is dependent on prospective unit capacity purchases of an unspecified amount in some years. See Sec. IV-C-5. It is recognized that a utility of Fitchburg's size is limited in its ability to build central generating stations on its own or as a lead participant. Given the current surplus in the region as a whole and the surplus of selected utilities in particular, reliance on prospective but uncommitted contracts to purchase surplus may be acceptable for a utility of Fitchburg's size and circumstances. However, with the successive losses and delays of planned nuclear units in the region over recent years, the Council is less prepared to accept, without seeing contracts or other evidence supporting the prospect, that surplus supplies are assured for the region through the mid 1990's. Clearly, the responsibility must fall on Fitchburg, and not on utilities such as NU or NEPCo, to assess the continuing availability of surplus capacity and any likelihood of competition among the region's capacity deficient utilities in contracting for any surplus energy over the next 10-15 years. As a CONDITION for approval of its 1983 Supplement, the Company shall in all future filings identify by source the capacity ranges of any significant unit purchases proposed, or planned on a contingency basis, from NEPOOL members. Where contracts have not been signed, the Company shall assess the availability and the cost of any planned capacity, particularly as it may be affected by regional competition, as part of the Company's plan to obtain such capacity.

Table 4

Comparison of Forecast Deficits and
Supply Options, 1985-1992

	85	86	87	88	89	90	91	92
Surplus (Deficit)	6.8	3.3	(29.6)	(31.8)	(34.7)	(37.1)	(39.5)	(41.8)
Supply Options								
Unit 7 conversion		-	-	10.0	10.0	10.0	10.0	10.0
Expander Turbine		.6	.6	.6	.6	.6	.6	.6
Hydro Quebec[1]		-	3.2	3.2	3.2	3.2	3.2	3.2
PASNY II		.1	.1-.3	.1-.3	.1-.3	.1-.3	.1-.3	.1-.3
FIBREX	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
FIBREX (additional)		13.0	13.0	13.0	13.0	13.0	13.0	13.0
BECo Replacement	-	-	30-40	30-40	30-40	30-40	-	-
Total Additional[2]	9.0	22.7	61.0	71.0	71.0	71.0	36.0	36.0

1. 3.2 MW Phase I is primarily an energy purchase. An additional 6.2 MW capacity purchase is being pursued as part of Phase II, but will not likely be available during the forecast period.
2. Assuming midpoint of ranges.

Capacity shortages are unacceptable to the Council for any year of the Forecast period. The Company should indeed continue to be active during the rest of 1984 in pursuing contract negotiations for the economic options. The Council intends to closely monitor Fitchburg's progress or lack thereof in pursuing contract negotiations capable of removing forecast deficiencies.

While the foregoing discussion relates to Fitchburg's supply options as a whole, the Council belives that a specific CONDITION is required regarding a prospective new contract to replace the existing Boston Edison contract. As indicated by Tables 3 and 4, in the absence of the Boston Edison contract beginning in 1987, and without additional capacity purchases, Fitcbhurg's capacity deficiency will be severe, indeed greater than its NEPOOL reserve requirements. Given the difficulties associated with negotiating such contracts, as evidenced by the lengthy discussions with Boston Edison, the Council seriously questions whether reliable and cost-effective purchases from other sources could replace the Boston Edison purchase in the event a replacement contract is not negotiated. The Siting Council's approval of Fitchburg's supply plan rests on Fitchburg's representation that a replacement contract will be negotiated with Boston Edison, a representation similar to the one made by the Company in 1982 in response to our last decision. The Council ORDERS the Company as a CONDITION to this Decision, to file an interim report before filing the next Supplement on the status of all discussions or negotiations for base and intermediate load capacity purchases. The Company shall make specific and detailed reference to the status of negotiations with Boston Edison including the terms of purchase. The Company shall substantiate its report with reports on meetings with Boston Edison, and with specific documentation (including documentation provided by Boston Edison to Fitchburg). The Council reserves the right to commence an inquiry into Fitchburg's supply plan.

D. Conservation and Load Management

The Company administers its own audit program, CONTACT, that has been providing over 1200 audits per year. Supplement Appendix AC. Based on follow-up information, the Company believes that customer response to audit recommendations is good. An average 10% reduction in heating-related electrical requirements of audited customers has been estimated and incorporated into the residential class forecasts. See sec. III-A, supra.

The Company also has actively pursued a rate restructuring, initiated in its latest rate case, DPU No. 1270. The Company proposed a new structure to better reflect costs of service by breaking out separate cost components, including customer, facility and energy charges. In addition, the Company sought to flatten its rates, while retaining time-of-use rates as an incentive for load management.[10] The Council commends the Company for pursuing these important changes in its rate structure, to the extent they can be supported by long-term cost of service analysis.

10. The DPU approved some rate simplification and flattening, but did not support Fitchburg's proposed level of facility charges. Fitchburg Gas & Elec. Light Co., DPU No. 1270 (March 1983).

With regard to programs for encouraging conservation and load management, the Company asserted in the current proceeding that passive methods (education programs, T-O-U rates) appear to be the most promising. The Company further stated that "[i]f capacity conservation is important, the level of charges can signal that to the customer." Supplement at 14-15. The Company did not provide any evaluation of the merits of more direct utility investment in or incentives for conservation and load management.

The Council appreciates that passive methods can provide a level of results at minimal costs, given a reasonable time period for such results to emerge. However, other utilities have begun to evaluate and in some cases to invest in more active approaches to conservation and load management, including direct financial incentives, as alternatives to expensive new capacity. Programs that offer shared savings to participating parties through utility installed or third-party financed conservation measures are examples of state-of-the-art approaches capable of benefitting both the utility and individual customers. As a capacity-deficient utility, Fitchburg should proceed to identify the most effective approaches for maximum capacity reductions and demonstrate the capability to systematically compare them with conventional supply planning options. As a CONDITION for approval of its 1983 Supplement, the Council hereby Orders the Company in its next filing to present a preliminary evaluation of both active and passive conservation-load management techniques, and describe its efforts and/or plans to demonstrate an integrated evaluation of the most promising conservation-load management techniques with the Company's options for capacity expansion.

V. Decision and Order

The Council hereby APPROVES the 1983 Supplement of the Fitchburg Gas and Electric Light Company subject to the CONDITIONS set forth below. The next Supplement is due November 1, 1984.

1. The Company shall review its residential and commercial forecast methodologies and related data collection needs in light of this and previous Council Decisions. The Company shall consider alternative approaches including use of econometric models, and shall develop a plan for addressing Council concerns regarding reviewability and reliability in an expeditious and cost-effective way. The Company shall submit a preliminary compliance plan within 90 days, and shall include a detailed compliance plan in its next filing. The Council Staff is available to meet with the Company to discuss Compliance with this Condition.

2. The Company shall begin development of a reviewable industrial forecast methodology which includes consideration of macroeconomic variables. The Company shall submit a preliminary compliance plan within 90 days, and shall provide a detailed compliance plan and report its progress in its next filing. The Council Staff is available to meet with the Company on request to discuss the requirements of this Condition.

3. The Company shall submit a detailed report (as an interim report before the next Supplement) on August 1, 1984, regarding the status of discussions or negotiations for all base and intermediate load capacity purchases, including Boston Edison Company. The report shall include supporting documentation.

4. The Company shall in all future filings identify by source the capacity ranges of any significant unit purchases proposed, or planned on a contingency basis, from NEPOOL members. Where contracts have not been signed, the Company shall assess the availability at reasonable cost of any planned capacity, including the effects of regional competition to obtain such capacity.

5. The Company in its next filing shall present a preliminary evaluation of both active and passive conservation-load management techniques, and describe its efforts and/or plans to demonstrate an integrated evaluation of the most promising conservation-load management techniques with the Company's options for capacity expansion.

James G. White, Jr.

James G. White, Jr.

On the Decision:

William Febiger

April 30, 1984

Unanimously APPROVED by the Energy Facilities Siting Council on April 30, 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); Joellen D'Esti (for Evelyn F. Murphy, Secretary of Economic Affairs); Charles DeSaillan (for James S. Hoyte, Secretary of Environmental Affairs). Ineligible to vote: Dennis J. LaCroix (Public Gas Member).

May 14, 1984

Date

Sharon M. Pollard

Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Eastern Utilities Associates for Approval of the Second Supplement to the Second Long-Range Forecast of Electric Power Needs and Requirements, 1983-1992	)	EFSC No. 83-33

FINAL DECISION

James G. White, Jr.
Hearing Officer

On the Decision:

Juanita M. Haydel

TABLE OF CONTENTS

LIST OF TABLES

I. INTRODUCTION

The Energy Facilities Siting Council ("Siting Council") hereby APPROVES the Second Supplement to the Second Long-Range Forecast of the Eastern Utilities Associates[1] subject to certain conditions outlined in Section IV.

A. Background and History of the Proceeding

Eastern Utilities Associates ("EUA" or the "Companies") is a Massachusetts voluntary association organized and existing under a Declaration of Trust dated April 2, 1928, and is a registered holding company under the Public Utility Holding Company Act of 1935. EUA owns directly all of the shares of common stock of two operating electric utility companies (the retail subsidiaries), Blackstone Valley Electric Company (Blackstone) and Eastern Edison Company (Eastern Edison). Eastern Edison owns all of the permanent securities of Montaup Electric Company (Montaup), a generation and transmission company, which supplies electricity to it, to Blackstone, and to municipal and unaffiliated utilities for resale. EUA also owns directly all of the shares of common stock of a service company, EUA Service Corporation. The holding company system of EUA, the retail subsidiaries, Montaup and EUA Service Corporation are referred to as the "EUA System".

The EUA System's retail subsidiaries supply electric energy to a combined service area of 539 square miles in Massachusetts and Rhode Island with an estimated 1983 population of 649,000.

Eastern Edison distributes electricity in two separate geographical areas in sourtheastern Massachusetts. The Brockton division of Eastern Edison consists of 17 communities located in the area surrounding the city of Brockton, serving a population of approximately 301,000. The Fall River division of Eastern Edison consists of five communities located in and around the city of Fall River, serving a population of approximately 147,000.

Blackstone distributes electricity in northern Rhode Island, serving Pawtucket, Woonsocket and five other surrounding communities with a combined population of approximately 201,000. Blackstone is not subject to the Siting Council's jurisdiction, however, the Companies submit its forecast voluntarily since it is an integral part of the System forecast. Rule No. 61.5(2).

EUA filed the current Supplement to the Second Long-Range Forecast of Electric Needs and Requirements on April 20, 1983. EUA provided public notice of the filing by meeting the Council's publication and posting requirements. The Council received no petitions to intervene. A prehearing conference was held on June 1, 1983 during which the Siting Council Staff and EUA agreed to defer active review until the filing of

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1. The Siting Council's October, 1982 decision in Docket No. 81-33 involved the Second-Long-Range Forecast. East. Util. Assoc., 8 DOMSC 192 (1982). EUA did not file a supplement in 1982. Thus, the current Supplement was denominated as the Second Supplement.

the Technical Supplement. EUA filed the Technical Supplement on August 31, 1983. The Council Staff issued three sets of Information Requests. In addition, the Council Staff met once with EUA's Technical Staff to discuss the third set of information requests. EUA has filed responses to the information requests, and provided supplemental information on the supply plan on February 21, 1984.[2]

II. ANALYSIS OF THE DEMAND FORECAST

A. Previous Forecasts

1. Third Supplement to the First Long-Range Forecast (Docket No. 79-33, 5 DOMSC 10 (1980)).

In review of EUA's Third Annual Supplement to its first Long-Range Forecast the Siting Council found that overall, the Companies' end-use approach was theoretically sound, but if implemented with a limited data base the results might be less than reliable. The Council found that EUA's estimates of critical parameters were often based on theoretically unsupported judgement, and were not based on reasonable statistical methods relative to the selected methodology.

The Council criticized EUA's forecasts of the number of residential customers and the number of new appliances, which were found to be based on various data that were neither timely nor service-territory specific. The Council also found EUA's forecast of average use for appliances to be problematic due to a limited data base.

Similarly, the Council expressed concerns with both the theoretical and statistical aspects of the commercial class forecast, in both the forecast of the number of customers and average use. The Council also found that in the industrial sector forecast, EUA relied to a greater degree than in other parts of the forecast on unexplained judgement, impinging on the reliability and appropriateness of the method. The Council also found the industrial forecast had a weak theoretical basis noting that no attempt had been made to identify the indicators of industrial activity and electricity use.

The Council approved the forecast subject to certain conditions. The Companies were ordered to reexamine the residential methodology, with emphasis on the development of timely and service-area-specific estimates of initial appliance saturations, appliance average use and base use. The Companies were directed to develop an analysis of fuel

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2. The Siting Council observes that a Supplement to a Long-Range Forecast constitutes a Petition (Rule No. 62.1), and that by statute the petitioner bears the burden of proof to demonstrate the Petition meets the statutory requirements. Mass. Gen. Laws Ann. ch. 164, sec. 69J. The Siting Council will endeavor to cooperate with the Companies to alleviate the burden where possible. Nevertheless, it is a requirement that each filing be self-contained, and be supported by sufficient documentation without reference to prior proceedings to allow the Council's Staff to review the current filing. Northeast Util. Co., 8 DOMSC 62, 87 (1982).

prices to support certain judgements and assumptions regarding future appliance penetrations and the future desirability of electricity. Additionally, the Companies were ordered to support the appropriateness of the method of projecting industrial and commercial sales by implementing a study of the composition and determinants of industrial and commercial growth and energy use.

2. Second Long-Range Forecast (Docket No. 81-33, 8 DOMSC 192 (1982)).

The Second Long-Range Forecast filed with the Council in 1981 was the product of an entirely new forecasting methodology which, overall, addressed the concerns expressed by the Council in Docket No. 79-33. The new forecasting framework was the product of several years effort and expense which involved the adaptation of the NEPOOL/Battelle Load Forecasting Model to the Companies' three service areas.

The Companies retained the services of a consultant for the area specific forecast of key demographic variables, constituting important exogenous input to the other forecasting models. Additionally, in response to demand condition 4 of the Decision in Docket No. 79-33, the Companies developed a class specific fuel price forecast for use in the model.

The Council unconditionally approved the forecast and praised the Companies for a new methodology that represented a significant advancement in their forecasting capability, both in terms of sophistication and credibility. The Companies were also commended for adding the forecasts of key economic and demographic variables to their methodology.

The Council did note that even the most appropriate methodology was worthless if inadequately supported with the requisite, service area specific data, and encouraged the Companies to incorporate the results of the 1980 Census, and the then planned residential survey as quickly as possible. Similarly, the Companies were encouraged to expand the commercial sector data base with more end-use specific information, and to continue the development of the industrial sector submodel.

B. Overview of the Current Forecast

EUA's adaptation of the NEPOOL/Battelle Model may be described as a detailed end-use model. It develops energy forecasts by examining components of power consumption in the major customer classes. The same basic model structure is used to make projections for each of EUA's three service territories. To capture differences between service territories, each area has its own data base.

In the residential sector, the model develops total energy use by multiplying the total number of household appliances times the average use per appliance. In the commercial and industrial sectors, consumption is a function of employment, historical trends in energy usage per employee, and the price of electricity.

The forecast of key economic/demographic variables required as input to the submodels were obtained through a contract with Planning Economics Group, Boston, Inc. The price forecast was prepared internally by EUA personel. Major assumptions, such as fuel oil prices and general inflation rates, were coordinated between the two forecasts for consistency.

The current forecast projects a 1.9 percent growth in the energy requirements of the affiliated Companies through 1992. Total system requirements, including sales to partial requirements customers, are forecasted to grow at the slightly slower rate of 1.8 percent per year. Peak loads for the affiliated Companies and the total System are projected to grow at annual rates of 1.2 percent and 1.1 percent, respectively. Table 1 summarizes the results of the Companies' system forecast.

A detailed description of EUA's adaptation of the NEPOOL/Battelle Model appears in the Companies' current filing and Technical Supplement, and in the Council's Decision on the 1981 forecast submission.[3] In the following description and discussion of the Companies' 1983 Forecast Supplement, the Council attempts to focus only on those improvements to the energy forecast methodologies and those areas where the Council sees need for improvement.

It must be stressed that EUA has made tremendous progress in the area of demand forecasting since its 1979 submission to the Council. The Companies continue to improve upon their forecast with this filing by the acquisition of additional service area specific data. The Companies documentation of the models is certainly worthy of emulation by larger utilities in the Commonwealth. Given data constraints, the Companies' current forecast meets the Council's criteria of reviewable, appropriate and reliable.

C. Economic and Demographic Forecast

Future population and employment levels, personal income, fuel prices and indicators of economic activity and inflation are important determinants of future energy demand. As in the Companies' previous forecast, EUA has retained the services of Planning Economics Group ("P/E") to provide forecasts of these key exogeneous inputs to the three forecasting submodels.[4] Planning Economics provided EUA with projections of population, per capita income, and price deflators for personal consumption expenditures and GNP. With the exception of the last two variables, these measures are specific to each of EUA's three service territories.

3. See 8 DOMSC 192 at 196-220; Long-Range Forecast, March 31, 1983, at p. II-1 to II-59 and Technical Supplement to the Forecast, September 1, 1983, Sections V to VIII.
4. See Technical Supplement, Section III, Report of the Planning Economics Group "Regional Economic Forecasts for EUA's Service Territories," (December 20, 1982).

Table 1

Eastern Utilities Associates

System Load Forecast

	Annual Energy (GWH)		Average Annual Compound Growth Rate
	1982	1992	1982-1992
Residential	1137	1252	0.97%
Commercial	1045	1410	3.04
Industrial	772	895	1.49
Street Lighting & Misc.	37	42	1.28
Total Affiliated Sales	2991	3599	1.87
Affiliated Losses + Internal Use	146	181	2.17
Total Affiliated Requirements	3137	3780	1.88
Sales for Resale	363	382	0.51
Montaup Losses	60	73	1.98
Total System Requirements	3560	4235	1.75
	Peak Load (MW)		
Blackstone Valley	231	249	0.75
Eastern Edison	390	447	1.37
Total Affiliated	621	696	1.15
Sales for Resale	44	46	0.45
System Losses	15	15	0.00
Total System	680	757	1.08

Source: Long Range Forecast, p. II-3.

The basic approach used in deriving the forecast of economic and demographic variables involved finding regression fits between county and national data series maintained by P/E and those maintained by EUA for its service territories.

Planning Economics has enhanced its product to EUA this year by further disaggregating its forecast of industrial employment in the three service territories and by using as the national measure of industrial activity the Federal Reserve Board Index of Industrial Production for various SIC codes, a variable previously unavailable. Planning Economics used thirty-eight regression equations to generate forecasts of industrial and commercial employment, per capita income, and population for EUA's three service territories, ten more specifications than supplied to EUA in the previous year.[5]

Population in the Blackstone service area is projected to decline less than two-tenths of one percent per year, while population in the Brockton and Fall River service areas is projected to increase at the rate of one percent per year. Real per capita income in Blackstone, Brockton and Fall River are projected to increase at average annual rates of 2.3 percent, 1.8 percent and 1.8 percent, respectively.

Commercial employment in Blackstone, Brockton and Fall River are projected to all increase at average growth rates of 2.4 percent, 3.5 percent and 2.6 percent, respectively. Industrial employment in Blackstone and Brockton are projected to have annual growth rates of 1.3 and 2 percent, respectively. Fall River is projected to see a decline in industrial employment of nearly 2 percent per year. Table 2 summarizes the results of the Economic/Demographic forecast by P/E.

Table 2

Economic/Demographic Forecast
Average Growth Rates

	Population	Per Capita Income	Commercial Employment	Industrial Employment
Blackstone	0.002	2.3	2.4	1.3
Brockton	1.000	1.8	3.5	2.0
Fall River	1.003	1.8	2.6	-1.9

5. For a detailed description of the specifications and the models used by P/E, see "Specification of the Regression Equations, Procedures used to Develop Forecast of Exogenous Variables", Docket No. 81-33; 8 DOMSC 192 at 199-201.

While other utilities in the Commonwealth have chosen to adopt the economic/demographic submodule of the NEPOOL/Battelle model,[6] EUA has chosen to use an independent forecast of these key variables. Given the problems inherent in using a regional economic model to simulate the activity in a utility service territory, the approach EUA has taken is possibly a more reliable, cost-effective method of obtaining this information.

The Companies have informed the Council that in the near future it will be evaluating the possibility of producing its own economic/demographic model.[7] Due to the distinct economic and demographic characteristics of its three service territories, it would be necessary for the Companies to develop three different models, as well as three different data bases. The Companies are commended for showing a commitment to the continuing development of the most reliable and cost-effective forecasting approach for the system characteristics.

D. Price Forecast

In Demand Condition 4 of the Council's Decision on EUA's 1979 Forecast, the Companies were ordered to support certain judgements about the future desirability of electricity with a detailed fuel price analysis.[8] In the Decision on the Companies' 1981 filing the Council found that "[t]he effort, and the documentation which was provided to the Council, are most certainly worthy of emulation by larger electric systems in Massachusetts. While the Council does not pretend that electric prices can be forecasted with any substantial certainty, the Companies have developed and documented an approach that constitutes a major step in dealing with this uncertainty."[9]

The electric price forecast is a major input to the residential, commercial and industrial forecasting model, and is itself dependent on the forecasted energy levels and peak demands. In this year's filing the Companies have used the same approach to forecasting electricity prices by class of service as used in the previous forecast, and as approved by the Council.

As a result of the electricity price/energy growth interdependency, the price forecast was developed in an iterative manner. Initial energy forecasts and peaks were assumed in order to develop the first price forecast. This price forecast was then used to drive the load forecasting model, which in turn generated new energies and peaks. This iterative process was continued until the change in electric price forecast from one iteration to the next was minimal.

The Companies are again commended for their excellently documented fuel price forecast.

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6. See Commonwealth Electric Co., (Docket No. 82-4) 1982 Long-Range Forecast and MMWEC, (Docket No. 82-1) 1982 Long-Range Forecast.
7. Response dated February 9, 1984 to Information Request No. 50.
8. 5 DOMSC 10 at 37.
9. 8 DOMSC 192 at 202 (emphasis in original).

E. Residential Energy Model

EUA's residential energy model is derived from the residential power submodel in the NEPOOL/Battelle Load Forecasting Model,[10] and is essentially unchanged from that used by the Companies in their 1981 filing.

The residential sector, which accounted for 36 percent of the total energy consumption of the affiliated Companies in 1982, is forecasted by EUA to grow at an average growth rate of 1 percent per year through 1992. The total number of residential customers is forecasted to grow at an annual rate of 1.4 percent through 1992, while the average use is forecasted to decline two-tenths of a percent per year. Electric heating customers are forecasted to grow at 3 percent per year, while average use by these customers is forecasted to grow at one-tenth of a percent per year. Table 3 summarizes the results of the residential forecast.

To develop the residential energy forecast EUA performs several steps which are discussed below.

1) an estimation of the number of households in the EUA service territories, derived from population;
2) saturation levels of the nineteen appliance types must be estimated; these saturation levels are applied to the number of households to compute the total number of appliances;
3) annual energy use for the nineteen appliance types are estimated and adjusted to account for several factors, including price elasticity, appliance efficiency improvements, changing family size, income changes, and appliance substitution.

1. Estimating the Number of Households

The Companies' general method for calculating the number of households is unchanged from their previous filing and will not be discussed in detail here. However, the Companies have been able to improve their product this year by incorporating data from the 1980 Census and the 1982 Residential Survey, data unavailable for the 1981 Forecast.

To account for differing household formation rates across age groups, the Companies disaggregate the population forecast for each service territory into six distinct age groups. Age-specific population estimates are converted to households through household formation rates.[11] After the total number of households is determined, they are split into owner/renter categories and single-family/non-single-family housing types.

10. See Report of the Load Forecasting Task Force of the NEPOOL Planning Committee, (October, 1981), "The NEPOOL Load Forecasting Model - An End Use Simulation Model for Long-Range Forecasting of New England Electric Energy and Peak Demand, Overview of the NEPOOL Model" and Part 1, Chap. 1, "Residential Power Submodule".
11. Also referred to as headship ratios or heads of households to population ratios and defined as the percentage of a particular age group which are heads of households.

Table 3

Eastern Utilities Associates

Residential Energy Forecast

	1983	1992	Average Annual % Growth 1983-1992
No. Residential customers	210,099	237,997	1.4
Average use (kwh)	5,343	5,261	(0.2)
No. Residential with heat	7,646	10,217	3.3
Average use (kwh)	16,097	16,204	0.1
No. Residential without heat	202,453	227,780	1.3
Average use (kwh)	4,937	4,770	(0.4)

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

Included from the 1980 Census are age-distribution data, household formation rates and housing split data. Included from the 1982 residential survey are housing split data. As in last forecast, the Companies use linear interpolation procedures and trends contained in the NEPOOL model to derive estimates of the above factors for years in which actual service area data are not available.

In order to compute the saturation levels of certain types of appliances, estimates of personal income for each service territory, as well as its distribution across housing types are necessary. Total personal income in each service territory is defined as the product of historical and projected per-capita income and population values, data supplied by P/E. Per-capita income is in real 1970 dollars, deflated by the Consumer Price Index. Once a service area's total personal income has been determined, the income is distributed across seven income classes and four housing types.

Census data were used in developing 1970 income distributions; additionally, information from the 1982 survey was used. Data from the 1980 Census was unavailable at the time the forecast was prepared.

The Companies are commended for updating the forecast with the most current data available. The Council encourages the Companies to continue to update the forecast as additional service area data, such as 1980 income distribution data, become available.

2. Estimating Appliance Saturations

As in the previous forecast submitted to the Council by EUA, the saturation levels[12] of eight of the nineteen appliance types treated in the model are forecast as a function of income.[13] As in the previous filing, these saturation/income functions were derived from the 1970 Census of Housing data for the three Standard Metropolitan Statistical Areas (SMSA's) appropriate to EUA's service territories.

The Companies originally intended to update the income/saturation functions used in the residential energy forecast by incorporating the results of the 1980 Census and the 1982 Residential Survey. However, for the present filing, 1980 Census data (covering space and water heating, cooking and air conditioning) were not available, and saturation/income equations produced from the survey were unreasonable and were not utilized.[14] In the future, the Companies plan to update the equations with the 1980 Census data and data from future surveys. The Companies currently plan to conduct a second residential survey in 1985. The Council urges the Companies to proceed with plans to update the 1970 appliance saturation/income equations, now 14 years old.

12. Saturation is defined as the number of a certain type of appliance as a percentage of the number of households.
13. Room and central air conditioners, electric clothes washers and dryers, electric ranges, dishwashers, and freezers (standard and frost-free).
14. Response dated February 9, 1984 to Information Request No. 4.

The saturation levels of the other 11 appliance types,[15] are not forecasted by income/saturation equations. The saturation levels of lighting and miscellaneous use are assumed to be 100 percent. The saturation of refrigerators (standard and frost-free), televisions (color and black and white) and microwave ovens are based upon data from the Residential Survey and data developed for use in the NEPOOL model. The number of fossil fuel heating auxilliaries is equal to the total number of households minus the number of electric heating households.

The projections of the numbers of electric heating customers are based on average penetration rates[16] in EUA's three service territories. The Companies do not possess true penetration rates, per se. Instead, the Companies have data on changes in total customer levels (all changes in customer levels are not represented by the addition of new customers only). The Companies calculated the average penetration rates based on the change in residential customers.[17] After adjusting to account for the conversion of master-metered units to individually metered units, the resulting penetration rates are 6.5 percent in Blackstone, 10.7 percent in Brockton, and 5.3 percent in Fall River.

In the previous forecast the Companies attempted to forecast the penetration of electric space heat as a function of the comparative installation and operating costs of oil heating and electric heating. The results of the study were not satisfactory due to lack of historical data, and the Companies decided upon a rate based on judgement.[18] The Companies have indicated that they may attempt to perform a penetration study in the future.[19]

The number of controlled and uncontrolled electric water heaters for 1982 is based on the Companies' Residential Survey and billing records. The forecast of the number of controlled and uncontrolled electric water heating customers are based on two assumptions. First, it was assumed that all new electric space heating customers would have controlled electric water heaters, and secondly, that the number of uncontrolled water heaters would remain constant at the 1982 level.

In summary, the saturation levels for the nineteen appliance types for 1982, 1987, and 1992 are shown in Table 4.

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15. Lighting, miscellaneous, fossil auxilliaries, frost-free and standard refrigerators, color and black and white televisions, microwave ovens, electric heating, controlled and uncontrolled electric water heating.
16. Penetration is defined as the percentage of new residential customers who choose electric space heating.
17. Response dated February 9, 1984 to Information Request No. 19.
18. Docket No. 81-33, Response to Question 12, Information Requests Set 2.
19. Response dated February 9, 1984 to Information Requests No. 50.

Table 4

Eastern Utilities Associates

Appliance Saturation Summary (%)

	Blackstone		Brockton		Fall River	
	1982	1992	1982	1992	1982	1992
Electric Range	55.1	58.3	73.7	76.0	43.1	45.2
Refrigerators	117.4	118.8	117.5	119.5	114.0	115.9
Freezers	36.8	38.3	33.2	34.5	36.5	37.8
Dishwasher	21.4	27.7	51.6	64.5	23.4	32.9
Clothes Washer	67.2	70.2	80.2	82.6	71.4	74.7
Clothes Dryer	43.6	46.9	52.3	55.3	36.0	38.3
Water Heater - Controlled	5.2	5.6	24.7	23.4	4.2	4.6
Water Heater - Uncontrolled	1.9	1.9	7.3	6.2	7.2	6.7
Microwave	16.2	60.0	13.6	58.0	14.1	60.1
TV - Color	112.3	132.0	117.0	135.0	120.0	138.5
TV - Black & White	85.1	59.0	92.1	65.6	76.6	54.6
Lighting	100.0	100.0	100.0	100.0	100.0	100.0
Misc.	100.0	100.0	100.0	100.0	100.0	100.0
Room AC	55.7	61.0	60.9	62.6	46.0	47.1
Central AC	1.2	1.4	6.5	7.0	0.7	0.7
Space Heat	1.7	2.1	5.4	6.5	2.2	2.6
Fossil Aux.	98.3	97.9	94.6	93.5	97.8	97.4

3. Average Use

The Companies method for calculating appliance saturations was discussed previously. The next step in the process is to calculate the actual number of appliances, a product of the number of households and the saturation of the particular appliance.

For a particular appliance and year, the total energy consumption is defined as the number of appliances times the connected load (appliance wattage ratings) and the number of hours of operation annually. A number of factors influence appliance annual use, such as electricity price, appliance efficiency improvements and family size. In reality, some of these factors influence appliance connected load, while others influence the average use by the household. In the model, since appliance electricity use is a product of connected load and the annual use pattern integral,[20] the assumption is made that the influence on hourly use factors is uniform, and the effects of the various factors are not partitioned.[21] Therefore, in the model the number of hours of operation is fixed and all required adjustments are performed to the connected load data for the initialization year.

As in the previous forecast, the Companies obtained connected load data for 1970, the initialization year, from NEPOOL. For non-temperature sensitive appliances, NEPOOL used national averages from a variety of sources, including Edison Electric Institute (EEI), the Association of Edison Illuminating Companies (AEIC), and NEPOOL member sources. For temperature sensitive appliances NEPOOL used data from NEPOOL member sources.

The Companies obtained the annual use pattern data from the NEPOOL Model. For non-temperature sensitive appliances NEPOOL obtained this data from load research findings reported by AEIC, from studies conducted primarily outside of the New England region during the late 1950's to the 1970's. Annual use pattern data for temperature sensitive appliances was obtained from studies done in New England in the 1970's.

In past Decisions the Council has expressed concerns over the use of the NEPOOL average use estimates, noting skepticism over the quality and currency of the data.[22] Citing that major changes in socio-economic and demographic characteristics since the time of the studies, as well as differences between geographic locations may affect the timing, level, and duration of appliance use, the Council has encouraged, and in some cases ordered companies to review and document the appropriateness of the use of NEPOOL data in company forecasts.

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20. This may be interpreted as the number of hours annually that the appliance is operating at full connected load.
21. For a complete discussion of the average use estimates in the NEPOOL Model see NEPOOL Documentation, Technical Chapter 1, p. 49 and Chapter 6.
22. See New England Electric System, 5 DOMSC 97 at 108 (1981) and 7 DOMSC 270 at 294 (1982); Boston Edison Co., 7 DOMSC 93 at 130 (1982); and 10 DOMSC 203, 220-21 (1984); and Commonwealth Electric Co., 9 DOMSC 222 at 313 (1983).

In the case of EUA, the Council criticized the Companies for the use of EEI estimates of average use in the 1979 forecast, noting that the Companies "should show that the estimates of average use which it chooses to utilize, be they national, state, or some sample of customers, are representative of electricity use in its service areas. With no service area specific information about average use per appliance in EUA service territories, the Council has no basis for confidence that national numbers used can represent or capture particular local characteristics."[23]

The Council remains skeptical of the use of the NEPOOL estimates without verification by the Companies. The Companies are therefore ordered to review the applicability of the NEPOOL average use estimates by conducting a literature review of existing load research data and presenting the results to the Council upon its completion. As the Council has noted in a past Decision,[24] the Companies should consider the applicability of the available data based on:

- the similarities and differences between EUA's service area and the source utilities' service territories;
- climatic similarities and differences;
- the date of the study;
- and, the credibility of the study.

We suggest the Companies initially concentrate their efforts on those appliances that are most energy intensive (ranges, refrigerators, freezers, water heaters, and space heating). Condition 1 addresses this issue.

Several adjustments are performed to the initial connected load values. To capture the effect on energy consumption due to changes brought about by changes in the real price of electricity, the connected load values are adjusted by an appliance specific price elasticity adjustment factor. The price elasticity within the adjustment factor includes a short-term component, to capture the immediate effects of a price change (change in the utilization rate), and long-term component, to capture the effects in the later years of the forecast (change in appliance stock). Also included in the adjustment factor is an appliance specific elasticity aging factor, included to relate how many years it takes a price change to be fully felt.

The specific short and long-term price elasticities and the elasticity aging factors are obtained from the NEPOOL Model. The elasticities are derived from a NEPOOL review of studies conducted in the 1960's and 1970's, using data series ranging from 1946 to 1974, and across various geographic locations including several national studies.

23. 5 DOMSC 10 at 19.

24. Commonwealth Electric Co., 9 DOMSC 222 at 317 (1983).

In the past the Council has expressed concerns over the use of the NEPOOL elasticities in service territory forecasts by Massachusetts utilities, while recognizing the difficulty of obtaining reliable estimates of price elasticity for each end-use modelled.[25] Accordingly, the Council has urged, and in some cases ordered several utilities to undertake aggregate price elasticity studies by class or to verify those price elasticities currently in use.

EUA has stated that it believes the NEPOOL price elasticities perform well for the Companies' service territories, however, has not presented the results of any empirical analyses.[26] The Companies are uncertain whether a price elasticity study would be beneficial or cost effective to their forecasting effort. In the previous EUA adjudication the Companies indicated that a price elasticity study was a long-term goal, but have expressed uncertainty about its plans regarding a future price elasticity study in this year's filing. However, the Council cannot continue to accept the use of the NEPOOL Model price elasticities without verification by the Companies. Therefore, we order the Companies to perform an aggregate price elasticity study by class of service. This should include at a minimum the price of electricity, and the price of alternative fuels and income. Condition 2 addresses this issue.

In addition to the price elasticity adjustment to connected load, the Companies make an adjustment to account for expected improvements in appliance efficiencies. The Companies base these estimates on efficiency standards promulgated in 1979 and 1980. However, the Department of Energy has recently completed a rulemaking in which it determined that mandated standards for eight appliances[27] would not result in significant conservation of energy or be economically justified. In making its determination, DOE relied on the Oak Ridge National Laboratory Residential Energy End Use Model, a model that projects energy savings attributable to a standard for a product.

The Company believes it appropriate to incorporate the old standards in spite of the implementation of the "no standard" standard, noting that consumers will continue to demand more efficient appliances, and manufacturers, who are tooled to meet the old standards, will strive to meet this demand.[28] We urge the Companies to reevaluate its assumption regarding appliance efficiency gains in the absence of a specific mandate, and in light of the work done for the Department of Energy by the Oak Ridge National Laboratory.[29]

25. See Commonwealth Electric Co., 9 DOMSC 222 at 328 (1983) and Northeast Utilities, 1 DOMSC 234 at 235 (1977).
26. Response dated February 9, 1984 to Information Request No. 42.
27. Clothes dryers, ranges, refrigerators, freezers, water heaters, room and central air conditioning and furnaces.
28. Response dated February 9, 1984 to Information Request No. 13.
29. See "Supplement to March 1982 Consumer Products Efficiency Standards; Engineering Analysis and Economic Analysis Documents;" United States Department of Energy, July 1983.

One final adjustment is the level adjustment applied to the residential forecast. The Companies indicate that this adjustment to non-temperature sensitive appliances is to calibrate the model to 1982 actual data. The NEPOOL Documentation indicates this is to regionalize the non-New England connected load data by comparing model produced aggregate Kwh with actual consumption for 1970. It is unclear from the Companies' documentation how exactly this level adjustment is derived and whether the forces that accounted for the shift in a pre-1982 consumption pattern will continue into the future. We request that the Companies enhance the documentation of the level adjustment in their next filing.

F. Commercial Sector Energy Model

As in the previous forecast, EUA used the commercial power submodule from its model which forecasts commercial energy as a function of employment in each service territory. The resulting forecast calls for a 3 percent annual increase in energy consumption.

The energy consumption in the commercial sector is assumed to be a function of the level of economic activity in EUA's three service territories, as measured by projected commercial employment. Employment projections for the service sector in EUA's territories were provided by the Companies' consultant, Planning Economics.

Applied to the projected number of employees is a derived measure of energy intensiveness, or annual energy consumption per employee. Measures of energy intensiveness (kwh/employee) were derived from employment and energy consumption data for the three service territories for the period 1970 to 1981. Commercial energy consumption is divided by the employment value and adjusted to account for the effects of price changes, thus the resulting energy intensiveness estimates are on the basis of a constant electric price.

For each service territory, the twelve historical values of energy intensiveness, on a constant price basis, are regressed over time to produce equations used to derive energy intensiveness in the forecast period.

In the model, the forecasted energy intensiveness values are adjusted to capture the effects of changes in price on consumption levels, necessary since the expressions for energy intensiveness were developed under a constant price assumption. This price elasticity adjustment factor (PEAF), is similar in form to that in the residential model. Within the PEAF are short and long-term elasticity components and an elasticity aging factor. The elasticity factors are presumably taken from the NEPOOL Model although the Companies' documentation is not clear on this point.[30]

Again, the Council's concerns are the same with respect to the use of the NEPOOL elasticities without verification (see discussion _supra_ at 14). We expect that the Companies' response to Demand Condition 2 will address the Council's concerns here.

30. See NEPOOL Documentation, Part 1, Chapter 3, p. 4.

One additional adjustment is performed on the commercial energy forecast to account for non-price,related conservation. EUA has assumed a 24 percent reduction in forecasted commercial class consumption in 1992 attributable to non-price related conservation and not incorporated into the PEAF. The adjustment is the same as that assumed in the previous forecast, trended two additional years. That is, in the last year's forecast the Companies judgementally estimated a 20 reduction in consumption in the commercial class due to non-price related factors in 1990; thus the variable CONS has a value of .98 in 1982, .93 in 1985 and .76 in 1992.

The Companies state that this adjustment is to simulate such factors as partriotism, heating and cooling standards and government mandates. The Council commends the Companies' recognition of these factors, however, we find that the Companies have not given rigorous treatment to these effects. The Companies conservation adjustment in the commercial sector requires a stronger empirical basis. The estimated potential load reduction through non-price related conservation is significant enough to merit more attention by the Companies.

One additional limitation in the commercial sector model is the level of detail of the data base. The Companies attempt to explain consumption in the commercial sector by examining historical usage trends over all building types and all end uses. For example, office buildings are combined with schools and hospitals, space conditioning is combined with lighting, in spite of different energy intensities and patterns of usage in each of these end-uses within the commercial class. No attempt is made to identify the behavior and factors which underlie consumption in these end-uses. The EUA forecast could be significantly improved with a more appropriate data base.

Accordingly, the Companies are urged to uphold their previously expressed goal to disaggregate all commercial class accounts according to two-digit SIC code. We realize that this is a long term project, requiring coding of over 10,000 customer accounts. However, the resulting data base will allow the Companies to forecast this sector on a disaggregated basis, resulting in a forecast that will capture the diversity of energy usage patterns present in the commercial class.

The Council would also like to commend the Companies' commitment to expanding its commercial and industrial sector data base with the commercial and industrial sector survey, planned for 1984. The information garnered from this effort should allow the Company to begin to compile the information necessary for a much more reliable end-use model.

G. Industrial Sector Energy Model

As in the commercial sector, and as in the Companies' previous forecast, the industrial energy forecast is dependent on economic activity in EUA's three service territories, as measured by employment. Unlike the commercial sector, the industrial sector, with the exception of Fall River, is disaggregated by two-digit SIC code. Fall River is forecast as a whole due to the lack of SIC specific data before 1976. In this year's filing the Companies have further disaggregated its industrial data base to include four additional SIC codes in Blackstone and one additional in Brockton.

For each service territory the product of the forecasted number of employees, provided by P/E, and of energy intensiveness (Kwh/employee), adjusted for price elasticity, yields the energy forecast for that sector.

Measures of energy intensiveness were obtained in the same manner as in the commercial forecast. Forecasts of employment were used to project the energy requirements of the industrial sector. The PEAF is derived in exactly the same fashion as in the commercial sector forecast except that the values of the short and long range elasticity components are different. It is not clear from the Companies' documentation what the source of these elasticities are, nor is it clear whether they are appropriate to the EUA territory. The Companies are requested to document in their next filing the source of these elasticities and their applicability to the Companies' service territory. See discussion at 14, supra. The Companies' response to Condition 2 in the next filing should address this issue.

In projecting future levels of energy intensiveness, the Companies assume that no change over those historical trends exhibited in the past, other than price induced, will occur. No adjustment is made in the industrial sector to account for conservation over and above that accounted for by the price elasticity adjustment factor. The Companies feel that the problems inherent in the commercial sector are not present in the industrial sector and no additional adjustment is required.[31] The Companies attempt to capture these autonomous affects in the commercial sector with the use of the conservation adjustment, although they do not support the assumption with empirical analyses. The Council is concerned that the Companies may have failed to capture changes in industrial energy intensiveness which may occur in the future due to technological change, changes in industry mix and efficiency of manufacturing procedures, government policies, and other non-price induced effects. We urge the Companies to continue development of the industrial sector model so that the projections of energy intensiveness incorporate all factors that are likely to influence consumption in this sector.

31. Response dated February 9, 1984 to Information Request No. 37.

H. Short-Term Modelling

The Companies have complemented their long-term forecast methodology with a short-term forecasting model. As the Companies have stated in their filing, long-term models are not designed to capture precise fluctuations in consumption, but rather long-term trends due to changes in population levels, industry mix, technology and other important factors. Short-term models, typically covering a period of one to three years, are able to incorporate seasonal variations and economic cycles, trends not captured by a long-term modelling approach.

Data Resources, Inc. (DRI), the Companies' consultant on this project, applied autoregressive integrated moving average models (ARIMA), also known as the Box-Jenkins approach, to produce a forecast for each of nine time series; sales to residential, commercial and industrial customers in Blackstone, Brockton and Fall River. As stated in DRI's report to EUA the ARIMA analysis "extracts the predictable movements from the observed history of a time-series own intrinsic historical properties."[32]

Each model is composed of a seasonal component, which compares each month in a given year to that month in previous years; and a normal component, which compares each month to recent growth trends.

The short-term forecasting model was used to produce projections for 1983 and 1984. After 1984, energy was increased at a constant rate until reaching the 1988 energy produced by the long-term model.

I. Peak Load

The Companies' System demand forecast was derived from the energy forecast by first considering load factor, and secondly, load management, a process in use by much of the electric utility industry today. Short-term load factors and "normal" long-term load factors were calculated. The Companies state that the 1982 load factor was considered unique to the short-term because although energy sales declined, peak loads were high, resulting in unusually low load factors. The 1982 load factors were used in projecting 1983 and 1984 winter and summer peak loads. A three year average of the load factors in 1979, 1980 and 1981 was considered a normal load factor and was used to project peak load in 1988 through 1992. In the intervening years, the load factor were assumed to be moving from short-term levels to long-term levels.

The Companies make an additional adjustment in deriving peak loads to account for the anticipated effects of load management, estimated to be a 4 MW reduction in 1983 and a 6 MW reduction in 1992.

The Council requests that the Companies expand their documentation of the effect of load management on peak demand, including assumptions made regarding water heater contribution to peak, as in the Technical Supplement to the 1981 Forecast.

32. See report by Data Resources, Inc., (October, 1982); "Box-Jenkins Analysis and Forecast of Monthly Energy Sales in EUA's Service Area."

J. Conclusions

Overall, the Companies' demand forecasting methodology meets the Councils standard of review. The methodology is appropriate to the EUA System; the documentation provided by the Companies render the models reviewable and worthy of duplication by some larger utilities in the Commonwealth; and given available data, the resulting forecast is reliable.

The Companies have shown a commitment to reducing its reliance on NEPOOL data, and in an effort to improve the reliability of the Companies' forecast, we encourage the Companies along these lines. We reiterate our concerns expressed in the preceeding discussions. We urge the Companies to:

- reestimate appliance/saturation functions, currently based on 1970 Census data;
- reevaluate the appliance efficiency improvements assumed in the model in light of the DOE rulemaking;
- more thoroughly document the residential level adjustment factor;
- provide an empirical basis for the conservation adjustment in the commercial sector;
- proceed with disaggregation of the commercial class accounts according to SIC codes;
- continue development of the industrial sector submodel;
- expand upon the documentation of the effects of load management on peak load in future forecasts.

The Council's more pressing concerns are outlined as Conditions to the approval of the demand forecast, infra at 46.

Table 5

Eastern Utilities Associates

Existing Generating Facilities
(as of 4/20/83)

	Unit	Location	System Interest (MW)	Type	System Interest
Base:					
	Somerset Steam	Somerset, MA	198	coal	Wholly Owned Capability
	Mass. Yankee	Rowe, MA	7	nuclear	Joint Ownership (4.5%)
	Conn. Yankee	Haddem Neck, CT	26	nuclear	Joint Ownership (4.5%)
	Maine Yankee	Wiscasset, ME	29	nuclear	Joint Ownership (3.6%)
	Vermont Yankee	Vernon, VT	12	nuclear	Joint Ownership (2.25%)
	Wyman No. 4	Yarmouth, ME	12	No. 6 oil	Joint Ownership (1.96%)
	Pilgram No. 1	Plymouth, MA	74	nuclear	Life of Unit Purchase Contract (11%)
	Canal No. 1	Sandwich, MA	142	No. 6 oil	Life of Unit Purchase Contract (25%)
	Colson Cove	Lorenville, N.B.	7 [1]	No. 6 oil	Purchase Contract (5.35%)
Intermediate:					
	Cleary No. 9	Taunton, MA	76 [2]	No. 6 oil	Purchase Contract
	Canal No. 2	Sandwich, MA	292	No. 6 oil	Joint Ownership (50%)
Peaking:					
	Somerset Jets	Somerset, MA	48	Jet Fuel	Wholly Owned Capability
			923		
Sales			(74)		
Net Generating Capability			849 MW		

(1) EUA is a joint participant with Maine Electric Power Co., receiving 7 MW in the summer of 1983 and continuing through October, 1985.

(2) Variable purchase contract with Taunton Municipal Light Plant. Amount represents entitlement through October 31, 1983. Montaup's share is expected to decline thereafter until it ceases (estimated to occur in power year 1986/87).

Source: Long-Range Forecast, p. V-13.

Table 6

Eastern Utilities Associates

Comparison of Resources and Requirements
(as of April 20, 1983)

	1982/83	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92
Existing Generating Facilities:										
Somerset Steam	198	189 [1]	186 [2]	186	186	186	186	186	186	186
Somerset Jets	48	48	48	48	48	48	48	48	48	48
Canal No. 2	292	292	292	292	292	292	292	292	292	292
Existing Nuclear	74	74	74	74	74	74	74	74	74	74
Wyman No. 4	12	12								
Total Capability and Joint Ownership	624	615	612	612	612	612	612	612	612	612
Purchases:										
Canal No. 1	142	142	142	142	142	142	142	142	142	142
Pilgram No. 1	74	74	74	74	74	74	74	74	74	74
Cleary No. 9	76	72	61	58	26					
Colson Cove	7	7	7							
Total Purchases	299	295	284	274	242	216	216	216	216	216
Sales:										
Newport	(15)	(15)	(15)	(15)	(10)	(10)	(10)	(10)	(10)	(10)
Pascoag	(2)	(2)	(2)	(1)	-					
Middleboro	(4)	(4)	(4)	(4)	-					
Braintree	(30)	(30)	(30)	(25)	(25)	(25)				
Taunton	(20)	(20)	-	-	-					
North Attleboro	(3)	(3)	(6)	(6)	-					
Anticipated Sales	-	(10)	(10)	(10)	(10)					
Total Sales	(74)	(84)	(67)	(61)	(45)	(35)	(10)	(10)	(10)	(10)
Capacity Purchases - Net of Sales	225	211	217	213	197	181	206	206	206	206
Planned Additions:										
Seabrook I [3]			33	33	33	33	33	33	33	33
Seabrook II [4]			-	-	-	34	34	34	34	34
Millstone III [5]			-	46	46	46	46	46	46	46
Total Planned Additions			33	79	79	113	113	113	113	113

(Table 6, continued)

	1982/83	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92
Net Capacity Available	849	826	862	904	888	906	931	931	931	931
Projected Peak plus Reserve Requirements	794	777	816	837	858	898	909	918	923	931
Excess or (Deficit) in NEPOOL	55	49	46	67	30	8	22	13	8	0
EUA Estimated NEPOOL Reserve Requirements (%)	19	19	21	22	22	24	24	24	23	23

(1) Somerset 5 & 6 rerated due to audit with maximum steam flow per boiler manufacturer's recommendation.
(2) Somerset 5 & 6 rerated due to coal operation with electrostatic precipitators.
(3) Seabrook Unit I on-line December, 1984.
(4) Seabrook Unit II on-line May, 1988.
(5) Millstone Unit III on-line May, 1986.

The two units began burning coal in March, 1983 under a Delayed Compliance Order (DCO) issued by the United States Environmental Protection Agency.[34] While burning coal under the DCO Montaup is in the process of installing state-of-the-art electrostatic precipitators, which, when installed, will allow the units to operate in compliance with clean air regulations and will result in fewer emissions from the plant than when it burned oil. The scheduled completion date for the installation of electrostatic precipitators is June 1, 1984.[35]

The cost of conversion, estimated to be $57 million, is being recovered through an Oil Conservation Adjustment (OCA) Rate approved by FERC, which allows Montaup to retain a portion of the fuel costs savings between oil and coal to pay for the cost of conversion. The remainder of the savings are passed on to customers. When conversion costs are fully recovered, 100 percent of the fuel cost savings will be passed on to customers. The System projects that annual savings will be $26 million initially.[36]

The capacity ratings of the units have been derated from 198 MW on oil to 189 MW under the DCO. With electrostatic precipitators the units will have a combined rating of 186 MW. The conversion, however, will allow the Companies to displace some 2 million barrels of oil per year from the System energy mix and provide 31 percent of the generation in 1992 with coal. The Siting Council commends the Companies pursuit of this cost-effective oil backout conversion within the appropriate state, local and federal guidelines.

C. Nuclear Additions

In making the load and capability projections shown in Table 6, the Companies made certain assumptions regarding on-line dates for three nuclear units presently under construction in which the System is participating. The assumptions underlying the forecast are an in-service-date for Millstone III of May, 1986, and an in-service-date for Seabrook I of December, 1984. These were based on the estimates of the lead participants in the project at the time of the filing. For planning purposes, however, the Companies incorporated a thirteen month delay into the lead participant's projected in-service-date for Seabrook II at the time of the filing. This moved the commercialization date from March 31, 1987 to May, 1988.

As the lead participant in the Millstone III project, Northeast Utilities, projects an in-service-date for that unit of May, 1986[37]. The Council finds this date to be acceptable in EUA's current filing. We note that in EUA's previous forecast it proposed to sell 2.0 percent, or 23 MW of its ownership interest in Millstone III, but later chose to retain its full share in the project and amended that filing.

34. The Delayed Compliance Order allows temporary violation of certain air quality standards.
35. Response dated August 12, 1983 to Information Request No. S2.
36. See Eastern Utilities Associates, 1982 Annual Report.
37. See Northeast Util. Co., Docket No. 83-17, Forecast, Vol. 2 at III-25.

Since the time of the Companies' filing several events have occurred regarding the Seabrook Project. In June, 1983, the Public Service Company of New Hampshire (PSNH), the lead participant in the project, revised its projected in-service date for Seabrook I to April 1985, and to July, 1985 for financial planning purposes. The Companies, in turn, revised their estimated in-service-date for Seabrook I to January 1, 1986.[38]

In September, 1983, the Seabrook Station Owners unanimously passed a resolution to reduce expenditures on Unit II to the lowest feasible level until fuel loading on Unit I took place, unless Unit II is cancelled at an earlier date.

On March 1, 1984 PSNH released the latest projections on costs and completion dates for the Seabrook Project. These most recent estimates are for a total cost of $9 billion for the two units, over 70 percent more than the $5.2 billion projected in 1982 and nearly 10 times the $970 million projected when the project was proposed in 1972. Most recent schedule estimates call for Unit I to be completed in July, 1986 and Unit II in December, 1990.[39]

At the meeting of the Joint Owners on that same day, four Seabrook owners sponsored a resolution to cancel the second unit. Seabrook participants holding 39.86 percent of plant ownership voted in favor of the resolution, while 44.83 percent voted against cancellation; 18.24 percent of ownership abstained. Montaup, holding 2.9 percent interest in the plant, abstained from the vote.[40]

In the last EUA decision, the Siting Council expressed concern over the ultimate completion date for the Seabrook Unit II.[41] This issue has been of continual concern to the Council in this and other EFSC dockets.[42] The most recent escalation in cost estimates and further scheduling delays have only heightened the Council's concerns over the Seabrook Project, particularly Unit II. As indicated by their votes in favor of cancellation, other New England utilities have determined that continued investment in the second unit at Seabrook is not in the best interest of their ratepayers and stockholders, nor part of an effective least-cost supply plan. Such may be the case with Montaup. While cost per kwh estimates provided by the Companies appear to show that Seabrook Unit II is a reasonable investment compared to other alternatives, the most recent cost estimate escalations render these figures virtually useless. Additionally, the most recently announced cost estimates and slippage of the on-line date are certain to increase the likelihood of

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38. Response dated February 3, 1984 to Information Request No. 74.
39. Seabrook Station Owners hope to reduce the projected cost estimates by restructuring management, among other efforts, and thus voted not to adopt the recently revised cost and schedule estimates. See PSNH Press Release, March 1, 1984.
40. Id.
41. 8 DOMSC 192 at 222.
42. See e.g. In Re Fitchburg Electric Co., 7 DOMSC 238 at 250 (1981); In Re NEES 7 DOMSC 270 at 312 (1982); In Re Comm. Elec. Co., 9 DOMSC 222 at 280 (1983).

cancellation of Unit II. Therefore, should Seabrook Unit II be included in the Companies' next supply plan filed with the Council, EUA is directed to indicate its position with regard to the desirability of completing that unit and provide the most recent cost estimates. Condition 3 addresses this issue.

In keeping with the mandate to insure that the EUA plans to meet projected needs with a supply strategy that is in fact least costly and environmentally acceptable, Mass. Gen. Laws Ann., Ch. 164, sec. 69H, the Siting Council also orders the Companies to provide with its next filing an analysis of the relative economics of continued participation in Seabrook Unit II, versus investments in alternative supply sources, including demand management strategies. Condition 3 also addresses this issue.

In its review in Docket No. 81-33, the Council chose to consider the Companies forecast without the addition of 34 MW of capacity from Seabrook Unit II within the forecast horizon. This resulted in a 1 MW shortfall in 1989/90 in the System's required reserves as established by NEPOOL. The Council found this unacceptable, and ordered the Companies to insure in their next filing that all NEPOOL reliability standards were fully met, taking into account potential delays in on-line dates for proposed nuclear additions.[43]

In response to that Condition, the Companies have presented a second load and capability scenario showing the effects on the System of an extended delay in the in-service-date for Seabrook Unit II, such that it does not come on line before 1993. Given the uncertainty surrounding the completion of Unit II and our concerns expressed above, we will again consider this scenario, in spite of PSNH's recent projection that the second unit will be on-line in December, 1990. Additionally we will revise the in-service-date of Unit I to July, 1986, consistent with PSNH's most recent projection. Table 7, in summary form, presents the Companies' load and capability forecast under these assumptions.

As indicated on Table 7, the Companies are able to absorb an additional one-year delay in the on-line date for Seabrook Unit I beyond that projected by PSNH, to power year 1985/86, provided Millstone III is completed as projected. Incorporating a delay into the in-service date of Seabrook II such that it is not on line before 1993, shows that the Companies will not have the required reserves in NEPOOL beginning in power year 1987/88, when the deficit is projected to be 26 MW, through 1992, when the deficit is projected to increase to 34 MW.

The Council notes that even if Seabrook Unit II comes on line in December, 1990, as projected by PSNH, EUA will experience reserve requirement shortfalls in the period 1987/88 through 1989/90 under the current load and capability forecast. The Council reaches this conclusion despite the Companies' statement that "the delay of one of the planned 1150 MW units would reduce reserve requirements significantly. ... This alone could eliminate any deficits through

43. 8 DOMSC 192 at 236, Condition 2.

Table 7

Eastern Utilities Associates

Comparison of Resource and Requirements
with Seabrook II Delay

	1982/83	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92
Existing Generating Facilities	624	615 (1)	612 (2)	612	612	612	612	612	612	612
Capacity Purchases - Net of Sales	225	211	217	213	197	181	206	206	206	206
Planned Additions:										
Seabrook I (3)				33	33	33	33	33	33	33
Seabrook II			-	-	-	-	-	-	-	-
Millstone III (4)				46	46	46	46	46	46	46
Total Planned Additions				79	79	79	79	79	79	79
Net Capacity Available	849	826	829	904	888	872	897	897	897	897
Projected Peak plus Reserve Requirement	794	777	816	837	858	898	909	918	923	931
Excess or (Deficit) in NEPOOL	55	49	13	67	30	(26)	(12)	(21)	(26)	(34)
EUA Estimated Reserve Requirement (%)	19	19	21	22	22	24	24	24	23	23

(1) Somerset 5 & 6 rerated due to audit with maximum flow per boiler manufacturer's recommendation.
(2) Somerset 5 & 6 rerated due to coal operation with electrostatic precipitators.
(3) Projected in-service-date for Seabrook Unit I of 7/86 (per PSNH March 1, 1984 projection).
(4) Projected in-service-date of May, 1986 for Millstone III.

Source: EUA Long-Range Forecast, p. II-55, adjusted to reflect revised in service date for Seabrook Unit I of 1/1/86.

1990."[44,45] While this fact does eliminate the projected deficits in reserve requirements in two of the five problematic years, the Companies still will not have the required reserves in NEPOOL in 1987/88, 1990/91 and 1991/92, when deficits will be 4 MW, 11 MW and 19 MW, respectively. Table 8 summarizes the Systems' load and capability with the reestimated reserve requirements.

In the Companies prior filing, the Siting Council found a 1 MW shortfall in capability responsibility unacceptable. Again, we find the currently projected shortfalls unacceptable and condition our approval of this forecast on the resolution of this issue. Therefore, the Companies are ordered to outline to the Council in its next filing a plan to meet the projected shortfalls in reserve requirements in the power years 1987/88 through 1989/90 assuming Seabrook II will be on-line in December, 1990; and in 1987/88 through 1992/93 should Seabrook II not be on-line during the forecast period. This plan shall include an analysis of the relative risks and economics of all alternatives, including demand management strategies, renewables and cogeneration. Condition 4 addresses this issue.

In response to our prior Decision and Order the Companies have outlined a number of supply alternatives currently under study or active negotiation which could impact the system capacity and cost in the 1987 to 1992 time frame. The alternatives include hydropower from Hydro Quebec and the Power Authority of the State of New York (PASNY), combustion turbine capacity in conjunction with Hydro Quebec Phase I, reactivation of Somerset Units 1, 2 and 4, and additional short and long-term capacity purchases. The Council requests that the Companies update the Council on these alternatives, and any other under consideration in its next filing, as far as is practicable. The alternatives currently under investigation are discussed below.

D. Future Supply Sources

1. Hydro Quebec

The Companies plan to participate in the NEPOOL planned economy interchange with Hydro Quebec. Phase I of this agreement, currently under contract, will provide a 690 MW link with Canada. Phase II, currently under negotiation could increase this link to 2000 MW.

Eleven year contracts were signed in March, 1983, consisting of three agreements. An energy agreement provides for Hydro Quebec to sell 33 billion Kwh of electricity to NEPOOL over the eleven year period, starting in October, 1986. Two-thirds of this energy will be

44. Supplemental Information, filed February 21, 1984.
45. Reserve Requirements are in part a function of the number of 1150 MW nuclear units on-line. The Companies estimate that a delay in Seabrook Unit II beyond 1992 would reduce reserve requirements by approximately 3% in power years 1987/88 through 1989/90 and 2% in 1990/91 through 1991/92. Id.

Table 8

Eastern Utilities Associates

Comparison of Resources and Requirements
with Seabrook II Delay and Revised NEPOOL Reserve Requirements

	1982/83	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92
Existing Generating Facilities	624	615 (1)	612 (2)	612	612	612	612	612	612	612
Capacity Purchases - Net of Sales	225	211	217	213	197	181	206	206	206	206
Planned Additions:										
Seabrook I (3)				33	33	33	33	33	33	33
Seabrook II			-	-	-	-	-	-	-	-
Millstone III				46	46	46	46	46	46	46
Total Planned Additions				79	79	79	79	79	79	79
Net Capacity Available	849	826	829	904	888	872	897	897	897	897
Projected Peak plus Reserve Requirement (5)	794	777	816	837	858	876	887	895	908	916
Excess or (Deficit) in NEPOOL	55	49	13	67	30	(4)	10	2	(11)	(19)
EUA Estimated Reserve Requirement (%) (6)	19	19	21	22	22	21	21	21	21	21

(1) Somerset 5 & 6 rerated due to audit with maximum flow per boiler manufacturer's recommendation.
(2) Somerset 5 & 6 rerated due to coal operation with electrostatic precipitators.
(3) Projected in-service-date for Seabrook Unit I of 7/86 per PSNH March 1, 1984 projection.
(4) Projected in-service-date of May, 1986 for Millstone III.
(5) Calculated using EUA's reestimated reserve requirements.
(6) Estimated Reserve Requirements per Supplemental Information, filed February 21, 1984.

Source: EUA Long-Range Forecast, p. II-55, adjusted to reflect revised in service date for Seabrook Unit I of 7/86.

prescheduled on an annual basis and priced at 80 percent of NEPOOL's average fossil fuel cost. The remaining third will not be prescheduled, but will be offered as available at the lesser of NEPOOL's replacement fuel or the Canadian price plus half the savings. An energy banking plan allows NEPOOL to ship off-peak power to Quebec and Hydro Quebec to return the power to NEPOOL during peak hours in New England. An interconnection agreement will allow NEPOOL to purchase surplus power on a short-term basis and provides for the supply of emergency power between systems.

NEPOOL participants will split the Quebec energy according to their percentage of NEPOOL's peak load. Based on 1980 sales, EUA is entitled to receive 3.78 percent of the energy, or 113,400 Mwh annually.

Phase II of the Hydro Quebec is currently under negotiation and would increase the capacity of the tie to 2000 MW. There is the possibility of firm capacity under this agreement and EUA estimates its share to be from 32[46] to 80[47] MW, with 490,000 Mwh[48] of energy annually.

2. PASNY

Additional hydroelectric power is expected as a result of allocation of hydro power from the Niagara and St. Lawrence PASNY projects to neighboring states. The allocation is expected to begin in 1985. An April, 1983 decision issued by an administrative law judge recommended allocating 31 MW of capacity to Massachusetts, without municipal preference, based on the number of residential customers (1/3), an Economic Dislocation Allowance (1/3), and state economic factors (1/3).

EUA estimates that under this allocation method Eastern Edison and Blackstone Valley will receive 2 MW and 3 MW of firm peaking power, respectively.[49] This decision is subject to appeal by the states and by municipals seeking preference in the allocation of power, so that the precise allocation is not known at this time.

3. Combustion Turbine Capacity and Reactivation of Somerset Units

The Companies are also studying the purchase of combustion turbine capacity from others, or the installation of similar equipment by EUA to, in effect, firm up a portion or all of EUA's Phase I Hydro-Quebec hydro energy allocation and make up any deficits caused by a delay in Seabrook Unit II. A gas turbine with a low capacity factor would be used to meet peak demand with minimal energy cost impact. In any event, EUA would use all available power from Hydro Quebec beginning in 1986/87.

46. Forecast, p.II-53.
47. Response dated February 9, 1984 to Information Request No. 73.
48. Forecast, p.II-53.
49. Response dated August 12, 1983 to Information Request No. S13.

The standard combustion turbine size is 75 MW, though smaller units are available. The installed cost of this type of capacity is estimated to be $250/KW in 1983. The Companies estimate a minimum 18 month lead time for delivery and installation.[50]

The Companies have also investigated the possibility of a unit contract purchase and have found two companies with such peaking capacity available. The Companies state that negotiations have begun with one of these companies and that when it appears to be in the best interests of the Companies' customers, a firm contract will be obtained for peaking capacity to meet capability responsibility until Seabrook Unit II or other base load capacity becomes operational.[51]

The Companies have also studied a combustion turbine as an alternative to reactivation of Somerset Units 1, 2, and 4 since Somerset Station would be the most likely site for such an installation. EUA performed a study to determine the economic feasibility of reactivating the Somerset 1, 2 and 4 thermal units in November, 1986 as an addition to the generation supply for the expected EUA System load conditions of the early 1990's.[52] Although the Somerset Units are more expensive to run than the combustion turbine, the Units' present worth of accumulated annual carrying charges may be less.

The addition of a 75 MW combustion turbine in 1992 was used as a benchmark for the analysis. Breakeven analyses between the Somerset Units and the benchmark case determine, within a range of economic parameters, the maximum capital investment that can be justified for reactivation of Unit No. 4 or all three units. The Companies are requested to provide the Council with the results of the final anaylsis of the reactivation of the Somerset units to meet capacity needs into the 1990's.

4. Other Supply Alternatives

The Companies have informed the Council of a number of other supply alternatives under investigation. These are summarized below.

EUA had been offered up to 70 MW of coal fired capacity from a New England utility looking for a 10 to 15 year commitment beginning in the late 1980's before proceeding with a planned conversion.[53] The Company determined that the offered price was too expensive to warrant the fixed charge portion of the rate. The same offer has now been extended to the entire POOL. Additionally, the supply would have been a short-term purchase and not a long-term source of capacity.[54]

50. Response dated June 22, 1983 to Information Request No. S18.
51. Supplemental Information, filed February 21, 1984.
52. See Draft Report No. 83-6 of Resource Planning Department of EUA Service Corp.,"An Economic Assessment of the Reactivation of Somerset Nos. 1, 2, and 4 Thermal Units."
53. Response dated August 12, 1983 to Information Request No. S18.
54. Response dated February 9, 1984 to Information Request No. 69.

The Companies also considered the merits of a purchase of 5 to 10 MW of capacity from the wood fired J. C. McNeil Plant in Burlington, Vermont. This capacity was expected to be available during the 1985-1999 period.[55] The Companies view this as a short-term purchase to be analyzed on an avoided cost basis. The offered price was greater than EUA's avoided cost, and thus was rejected.[56]

The Companies have also indicated that it may be possible for the System to take smaller yearly entitlements from Taunton Municipal Light Plant's Cleary No. 9 unit so that the current contract is extended over a longer period of time, offering a short-term solution for capactiy deficits in the mid to late 1980's.[57] Montaup, however, cannot extend its purchase of Cleary No. 9 power beyond the 25 percent life output of the Unit.[58]

The Companies have also indicated that they may study the purchase of capacity from the proposed Canadian Point Lepreau II nuclear unit, independent of NEPOOL, but are waiting to get a firmer idea on Hydro-Quebec Phase II before proceeding with this analysis.[59] The New Brunswick Power Commission has announced that it is prepared to construct a second nuclear unit at Point Lepreau for long-term export to interested New England utilities on a unit participation basis. Point Lepreau II would be a 630 MW CANDU unit, essentially a replica of the existing Unit I. Capacity and energy could be available as early as 1989 for a period of up to 20 years. Prices would be established to ensure recovery of costs plus a reasonable markup. Capital costs are estimated at $2 billion and power costs at 6 to 9 cents per kwh in 1989.[60] The New England utilities possibly would benefit from the project without incurring the risks usually associated with the construction, licensing and operation of nuclear units in the United States. A number of New England utilities are currently participating in the Point Lepreau Unit I, purchasing approximately 1/3 of that Unit's capacity and energy output.

E. Conservation and Load Management

The Council has consistently urged companies to evaluate the potential of conservation and load management as a means of achieving a least-cost supply plan. The Council has addressed these issues in past

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55. Response dated August 12, 1983 to Information Request No. S18.
56. Response dated February 9, 1984 to Information Request No. 70.
57. Response dated February 9, 1984 to Information Request No. 72.
58. Id; Due to an IRS rule which will remove Taunton's tax benefits if it finances more than 25 percent of a plant for an investor owned utility, Montaup is restricted from purchasing more than 25 percent of the net capability of Cleary No. 9, estimated at 825 MW-years. Taunton Mun. Lighting Plant, Docket No. 83-51, Forecast at V-13.
59. Response dated February 9, 1984 to Information Request No. 73.
60. Presentation by Premier Hatfield on the Point Lepreau nuclear generating station, at the Eleventh Annual Conference of the New England Governors and Eastern Canadian Premiers, June 21, 1983.

review of EUA's forecasts and supply plans. The following sections review the progress EUA has made in this regard. Specifically, the Council reviews Eastern Edison's proposed conservation and load management program, EUA's existing water heater control program and other initiatives underway by the Companies.

1. "Teaming Up"

The retail Companies of EUA, Eastern Edison and Blackstone Valley, have prepared similar conservation programs. The program, entitled "Teaming Up" was initially filed with the Massachusetts Department of Public Utilities (MDPU) on behalf of the Eastern Edison Company in August, 1982. The "Teaming Up" proposal was prepared in response to an order of the the MDPU to submit a program that could be implemented in a manner consistent with currently approved programs.[61]

Eastern Edison proposes to conduct the program for three years commencing with approval by the MDPU and to recover associated expenses through a monthly assessment to all of the Company's customers.[62] As of November, 1983 Eastern Edison had not begun implementation of the program.[63] This is of concern to the Council. Regardless of the Company's reason for delay, the Council believes the delay is inconsistent with sound supply planning and possibly inconsistent with established MDPU practice. The Council urges the Company to proceed with implementation of the program consistent with Council concerns outlined _infra_, _and_ consistent with MDPU established ratemaking principles. We direct the Company to inform the Council of its progress in implementing its Teaming Up proposal in its next filing. This issue should be addressed in the context of the Companies' response to Condition 5.

Eastern Edison's proposal consists of four parts which are designed to reduce energy consumption and demand for electric space heating and water heating customers as well as providing basic weatherization services for low-income customers. As the Companies state "[t]he purpose of this program is to gauge, in a controlled manner, customer response to a number of specific economic incentives. In addition to gathering data, the monitoring of selected installations will help the system to quantify the energy and demand benefits of heat pumps, storage and conservation technologies."[64] The program components are summarized below.

61. Eastern Edison Co., MDPU No. 837/968 at 52-55 (1982).
62. Blackstone Valley Electric Company is currently implementing the "Teaming Up" Program in its service territory. Brief, _infra_ n. 63 at 24.
63. See Initial Brief of the Executive Office of Energy Resources, MDPU No. 1580, at 24 (November 23, 1983).
64. Direct Testimony of Arthur A. Hatch, before the Massachusetts Department of Public Utilities, Eastern Edison Company, MDPU No. 1580. Submitted in Response dated February 9, 1984 to EFSC Information Request No. 55.

1. Weatherization Grant Program

Grants of up to $300 awarded to electric space heating customers who install certain weatherization measures. Eligible customers will be reimbursed 15 percent of the cost of the qualifying measure(s). The grant is not applicable to renewable energy devices.

2. Electric Water Heating Conservation Program

Eastern Edison will subsidize the installation of water heater wraps, low-flow shower heads, and water heating heat pumps. Customers may elect to have a water heater wrap for $10.00 and a low flow shower head installed for $5.00. The customer may elect to have other energy saving devices installed at the same time, at cost.

Grants of up to 15 percent of the cost of purchasing and installing a water heater heat pump (not to exceed $150) will be awarded when connected to an off-peak controlled circuit.

3. Electric Resistance Heating Conversion Grants

Residential customers who convert from electric resistance space heating to off-peak controlled storage or heat pump systems will qualify for reimbursement of 20 percent (not to exceed $800) of the installed cost of conversion.

4. Conservation Kits

Free conservations kits will be provided to low-income families who have had a fee-waived Mass Save Energy Audit.

The grant amounts, 15-20 percent of the cost of purchasing and installing qualifying measures, are intended to approximately cover the interest charges of a loan for 18 months (15%), and for 24 months (20%), assuming an annual percentage of 18 percent or a simple interest rate of 10 percent per year. The grants therefore are designed to be the equivalent of a zero-interest loan.

The first three elements of the program restrict eligibility to homeowners of a residential dwelling of one to four units. Programs 1 and 4 further restrict eligibility to those customers who have had a Mass Save Audit. In the case of the free conservation kits, a fee-waived Mass Save Audit is a requirement. It should be noted that the fourth element of the proposal is the only program available to tenants. Table 9 summarizes the program components, expected number of participants, expected energy savings and payback period. The Council notes that the estimates of program participation, cost and energy savings are based in part on borrowed data and judgement and actual results may be considerably different from the Company's projections.

Table 9
Eastern Edison Company Conservation Program
"Teaming Up"

	Program	Eligibility	Grant Amounts	Estimated No. of Participants	Customer Costs	Company Costs* (Grant expense)	Energy Savings (Kwh)	Simple Payback
1.	Weatherization Grant	Electric Space Heating Customers who are owners of homes (1-4 units) constructed prior to 6/1/82 and have had a Mass Save Audit.	15 percent, up to $300, of cost of installed qualifying measures.	535	235,000	35,000	1,240,000	2.1 years
2.	Electric Water Heating Conservation Plan	Electric water heating Customers who are owners of homes (1-4 units) constructed prior to 6/1/82.						
	a. Water Heater Wrap Flow Restrictor; Other items		Amount in excess of $10 and $5, respectively; Other items at cost	6000	90,000	138,000	18,344,000	2.0 months
	b. Water Heaters Heat Pump	Heat Pumps must be connected to off-peak circuit	15 percent, up to $150 of the installed cost of the qualifying measure	150	150,000	22,500	450,000	4.8 years
3.	Electric Heating Conservation Subsidies	Electric Heating Customers who are owners of homes (1-4 units) constructed prior to 6/1/82.	20% of installed cost not to exceed $800					
	a. Controlled Storage Heat			30	240,000	48,000	98,610	13.5 years
	b. Electric Heat Pump			30				23.0 years
4.	Free Conservation Kits	Low-income families who have received a fee waived Mass Audit.	-	2900	-	43,000	550,000 gallons of oil equivalent	Immediate

* Excludes Company administrative costs.

The programs appear to be well directed. That is, they are aimed at those devices that are most energy intensive.[65] The program also concentrates on those measures with the quickest payback and widest customer appeal. The Council is concerned that the programs are for the most part not directed towards tenants and completely exclude the commercial and industrial sectors.[66] The Council encourages the Companies to address these gaps in its programs in the future.

After long encouraging EUA to adopt a conservation program, we find the "Teaming-Up" proposal acceptable as an initial effort. The proposal should allow the Companies to acquire territory-specific information and experience on conservation and load management programs, monitor the effects of individual programs on consumption and on ratepayers' bills (including those of non-participants), analyze the life-cycle costs and benefits of individual programs and to develop a statistically reliable conservation data base.

However, in order to accomplish these goals it is imperative that the Companies conduct their programs in a manner that will allow them to monitor and evaluate the results in a statistically reliable and reviewable fashion. Therefore, the Council orders the Companies to present to the Council in their next filing, or as soon as is practicable, a framework for monitoring and evaluating its "Teaming Up" proposal. Specifically, the Companies should address how they plan to:

-collect information on the effect of each program including cost, participation levels, saturation of program measures, demographics of participants and energy savings achieved;
-compare programs with conventional supply sources;
-assess program components with each other on a comparable basis;
-segregate the energy or demand reduction attributable to Company programs from that attributable to other exogenous variables (e.g. energy prices, weather, government programs, economic conditions);
-assess the reliablility of demand reduction strategies and their cost;
-integrate the conservation data base with the demand forecasting data base; and
-incorporate the Teaming Up proposal with existing informational and promotional programs.[67]

65. Water heating accounted for 15 percent of the energy consumption in the residential sector in Eastern Edison's service territory in 1982, while electric space heating accounted for 5 percent. Forecast p. II-30.
66. Twenty-seven percent of Eastern Edison's residential customers are renters. Thirty-seven percent of EUA's residential customers are renters. See 1982 Residential Survey, Technical Supplement p. V-16.
67. EUA has conducted several conservation initiatives in the past and currently has several underway, including informational programs, a residential audit program, a water heater conservation program including wraps, off-peak water heating rates for controlled storage water heating, discussed below, a model water heating program, and a water heater heat pump pilot program. "Teaming Up", p. 7-10, Response to Information Request No. D2.

The Council urges Eastern Edison to proceed with implementation and monitoring of its proposed conservation program in a manner consistent with Council requirements outlined above and in a manner that will pass muster with the Department of Public Utilities' established ratemaking principles as applied to the recovery of conservation and load management expenditures.[68]

2. Water Heater Control Program

In the Council's Decision on EUA's 1979 Supplement the Companies were ordered to assess the potential for direct control of major residential and commercial loads for purposes of load factor improvement. The Companies responded in their 1981 filing by stating that due to System characteristics, the most effective load management option should concentrate on controlling water heaters. The peak demand forecast in that filing was reduced to show the impact of a load management system that would have the ability to control every water heater on the system by 1987, resulting in an 18 MW reduction at the time of peak in 1990.

Admitting the assumption was optimistic, the Companies outlined no specific means to achieve this goal, since at the time some 14,000 existing electric water heaters were not separately metered. The Council encouraged the Companies to continue their efforts and stated that it expected the Companies to outline in its next filing the results of the study on the feasibility of converting all water heaters to controls by 1987, the load management effects, and the required mechanism.

In this year's forecast the Companies have presented a less optimistic load management program for electric water heaters. It is assumed that all new electrically heated homes will have a controlled electric water heater and no conversion of presently uncontrolled electric water heaters will occur.

Approximately 26,000 electric water heaters on the Companies' system are currently controlled by standard time clocks. EUA projects to increase this figure to approximately 29,000 by 1992. Again, the Companies have offered no mechanism by which to achieve this goal. Presumably the savings resulting from the differential in rates for uncontrolled and controlled water heaters will provide sufficient incentive to customers to invest the additional money for a controlled system.

As noted in the Companies' study on the direct control of water heaters, discussed in detail <u>infra</u> at 40, the time clocks are subject to reliability problems such a a 5 percent failure rate and maintaining correct time settings. The Direct Control Study recommended that the Companies investigate ways to improve the current time clock scheme via better maintenance, clocks with battery carryover, alternative meters from different manufacturers, and more sophisticated control schemes

68. Western Mass. Elec., MDPU No. 1300 (1983), at 88-95 and Boston Edison Co., MDPU No. 1350 (1983), at 135-140.

where cost-effective. Another study completed by EUA Service Corporation[69] noted that in order to optimize effective control of water heaters more than one control period should be established and a specific number of heaters should be controlled under each time period. This would have the effect of nulling the payback phenomenon[70] and enable additional savings as more water heaters are added to the system. Regarding the current time clock system it also recommended the study of new rates or rate incentives to attract customers to adopt control of water heaters, the gathering of data on diversified load of water heaters in the Brockton area and the study of the payback effect and water heater control strategies in detail.

Given the previously discussed problems with the time clocks; and benefits to be gained from more than one control period, the Council is concerned that the EUA System may not be maximizing the potential benefit from its current water heater control program. Rate structures, Company promotional policies and proper maintenance of existing time clocks will have a major impact on the success of the program. The rate structure must be designed so that there is sufficient incentive to offset the additional cost of load management equipment and the system must be operated and maintained to insure reliability and maximize potential peak reduction.

The Council notes that the generic load management study was completed more than 2 and one-half years ago and the Companies in fact may have further studied its recommendations. However, the Council has nothing before it in this regard. To date, EUA has not presented a study outlining the feasibility of its water heater control program, the detailed load management effect, and the mechanisms required to achieve its stated goal, despite the Council's stated interest in these issues.

The Council therefore orders the Companies to provide to the Council with its next filing information detailing all measures they have taken to insure that the System is receiving the maximum potential peak reduction from existing controlled water heaters, including minimizing reliability and maintenance problems and controlling blocks of water heaters at different times so as to minimize the payback effect. The Companies are also directed to outline the feasibility of its current plans to control all electric water heaters in new all-electric homes including all rate and other incentives analyzed by the Companies to attract customers to time clocks, as well as promotional activities undertaken by the Companies. These issues are addressed in Condition 6.

As the Company notes, control by standard time clocks allows the ability to shift energy usage, however, it does not allow the flexibility to shift significant amounts of peak load. Also, as discussed above, the time clocks have inherent problems with them, such

69. Habib E. Merchant, Report of the EUA Service Corporation (July, 1983), "Generic Overview of Load Management".
70. "Payback" refers to the amount of water heater load which will appear immediately following a control period in which the water heater has been off.

as a 5 percent failure rate, maintaining correct time settings, etc. As an alternative and improvement to time clock control the Companies' Load Management Task Force undertook a study to evaluate the potential of direct control of water heaters with relationship to time clock control. In order to determine the potential benefit of each system, the study compared the continuation and expansion of the present time clock system to direct phase in of Direct Control by quantifying the resultant capacity savings due to peak reduction versus the cost of each method (capital, O & M, etc.).

The Task Force concluded that although greater capacity savings and greater gross savings would result from a direct control system over the present time clock system, the sizeable investment involved would result in an annual levelized savings equivalent to that provided by the present time clocks (approximately $1 million).

In evaluating the direct control scheme the Companies made certain assumptions regarding future capacity additions. It was assumed that Seabrook I and II would come on-line in 1985 and 1990, respectively; and that the Companies would receive 30 MW in 1989 from EG&G's New England Energy Park, proposed for a site in Fall River, and 12 MW in 1991 from Hydro Quebec, resulting in excess capacity for the System into the late 1990's. It was assumed that EUA would maintain excess capacity of 10 MW (above capability responsibility) and any amount above 10 MW would be available for sale. Capacity savings were calculated based on the capacity sold in Canal No. 2, the most marketable unit at that time.

Earlier in this Decision we have expressed our concerns regarding the timely completion of Unit II at Seabrook and the ultimate cost of that Unit. The projected commercialization date for Seabrook Unit I has again been changed to July, 1986. Also, capacity from the EG & G project is no longer a near-term option for the Companies[71] and whether Hydro-Quebec Phase II will include capacity entitlements is an uncertainty.

As the Companies note in the evaluation, "the economic worth of a direct load control system would be enhanced in the late 1990's when capability shortages will occur, or before if other controllable loads can be integrated into the system."[72] The Companies estimate that, if necessary, direct control would allow the System to pick up 17 MW of peak reduction in a three year time frame to forestall the need for additional capacity.

As noted earlier, under the Companies' current load and capability forecast, and assuming Seabrook Unit II does not come on line before 1993 shortages could occur as early as power year 1987/88.

71. EG & G failed to receive the necessary loan subsidies from the U.S. Synfuels Corporation in June, 1983 and withdrew its petition pending before the Council. Docket No. 82-42.
72. EUA Resource Planning Department Report No. 83-1 (January, 1983), "Load Management: Cost/Benefit Comparison Between Time Clock Control and Direct Control (Altran)."

Accordingly, it would seem prudent for the Companies to reevaluate the direct control scheme in light of its most recent load and capacity forecast incorporating the potential delay of Seabrook II beyond 1993 and the revised Seabrook I on-line date and compare the costs and benefits of the control scheme to the cost of all alternative capacity additions or purchases under study.

3. Other Load Management Options

The Direct Control Study also recommended that EUA investigate the feasibility of controlling loads other than water heaters such as deferrable industrial/commercial loads and air conditioning loads and to reexamine the direct control scheme. The Companies have indicated that in the future they will conduct those studies recommended by the Direct Control Study.[73] EUA has also stated that it will comprehensively examine all controllable loads and is particularly interested in interruptible rates, storage heat and heat pumps.[74]

As the Companies internally prepared document points out "[t]he development of a comprehensive load management strategy is essential for capacity planning around and beyond 1990."[75] As is noted there, an appropriate way for planning for a capacity deficiency situation is "by managing and controlling selected loads as well as evaluating capacity additions."[76]

In addition to deferring and/or reducing capital investments in generating capacity, a well-designed, comprehensive load management strategy can improve the reliability of the existing generation and transmission system and by introducing flexibility to the system, reduce operating costs, reduce spinning reserve requirements and reduce uncertainty costs by allowing the Companies to adjust to unforseen events more quickly than traditional power supply projects.

The Council believes that conservation and load management should be an integral component of a least-cost supply strategy for EUA, especially given EUA's potential capacity shortfalls in the late 1980's and in the 1990's. A company's long-term power supply planning should give equal consideration to load management and conservation as that given to conventional energy supply sources. The Council feels that the Companies should be more aggressive in the pursuit of cost-effective load management strategies.

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73. Response dated August 12, 1983 to Information Request No. S20; Forecast p. II-58.
74. Response dated February 9, 1984 to Information Request No. 59.
75. "Generic Overview of Load Management", <u>supra</u> n. 69 at 1.
76. <u>Id</u>.

With the exception of the "Teaming Up" proposal[77] EUA has not presented to the Council a plan for the systematic and comprehensive evaluation and implementation of all feasible load management strategies, although it has stated that it will conduct several such studies in the future.[78] The Companies should draw up a priority list of the potentially cost-effective load management options for EUA; select strategies for detailed analysis, estimate modification to load shape and resulting costs and benefits; choose the most favorable set of strategies; and develop a plan for implementation.

We therefore order EUA to present to the Council with the next filing its plans for studying direct and indirect load management stategies covering all feasible controllable loads. The Companies should outline its plans to study storage heat, heat pumps, air conditioning control for all classes, interruptible rates, time of use rates, and peak control time of use rates. Condition 7 addresses these issues.

F. Renewables and Cogeneration

The EUA System's pursuit of renewable resources and cogeneration has been of continual concern to the Council and the subject of conditions in the last two Decisions on the Companies' forecast. The Council in EFSC 79-33 conditioned its decision to the effect that "the Council encourages EUA to pursue actively and support the promotion of renewable resources and cogeneration in Massachusetts. The next EUA filing should address this point."[79] The Companies response to this in its 1981 filing was "...EUA supports such endeavors and includes them in its forecast, when known."[80]

The Companies also cited their pursuit of low-head hydro. The Council commended these effort, but found that due to circumstances which had transpired since the filing it had "become imperative that the Companies pursue alternatives such as renewables, cogeneration and load management."[81] The Council conditioned its approval of the filing on the development of a "unified long-range supply plan which shall set forth the Companies plans for filing the potential Seabrook 2 gap, discuss oil backout strategies and vigorously explore all conservation and alternative supply options available to the Companies."[82]

77. Teaming Up, the Company's initial conservation and load management program discussed supra at 36, is primarily concerned with water heater controls and water heater heat pumps, controlled storage heat, and heat pumps in the residential sector.
78. We take note here of the comprehensive plans prepared and implemented by New England Electric System (NEESPLAN) and Northeast Utilities (Program for the 1980's and 1990's).
79. 5 DOMSC 10 at 38.
80. EUA (Docket No. 81-33), Forecast at II-52.
81. 8 DOMSC 192 at 234.
82. Id.

We again take note of Blackstone Valley's pursuit of low-head hydro. Table 10 summarizes expected sales to Blackstone from hydroelectric facilities currently under contract. The Blackstone Falls, Roosevelt and Woonsocket Hydro facilities are business ventures designed solely to sell hydroelectric energy to Blackstone Valley. The Tupperware facility was installed to produce energy for the owner, however, Blackstone has agreed to purchase all surplus-energy. All of the facilities operate under run of the river conditions with no pondage, therefore these sites offer no firm capacity. In 1984, when Blackstone's Pawtucket Station No. 2 goes on-line, system energy from low-head hydro sites is expected to total 24,700 Mwh per year.

EUA states again this year that it is actively supporting other potential power producers as well as cogenerators within its service territory. The Companies have participated in preliminary discussions in a number of trash to energy project, the most recent in 1983.[83] However, none of the projects are currently active.[84] The Companies also stated that they have surveyed all potential low-head hydro sites within the service territories. With the exception of two sites in Rhode Island, one of which is currently being developed by Blackstone Valley, none were identified with economic potential.[85] The Companies state that "[u]nder federal regulations EUA will buy energy from any privately developed site. We therefore assume the market incentive will lead to efficient development of private sites."[86] The Companies state that they have provided whatever technical assistance potential cogenerators or small power producers have requested.

We note that the Companies study of the low-head hydro potential in its service territory is over five years old, and appears neither comprehensive nor systematic.[87] The Companies have performed no recent assessment of the small power and cogeneration potential within and outside of its service territory. To the Council's knowledge, the Companies have set no goals in the area of small power and cogeneration nor have they adopted progressive contractual policies, such as a minimum floor pricing where appropriate.

We feel that the Companies, particularly Eastern Edison, have not been aggressive enough in the encouragement and pursuit of power from small power producers and cogenerators. Given the Companies' potential capacity shortfalls in the late 1980's and 1990's, we once again find it imperative that the Companies take a more active role in the pursuit of these options.

83. See Direct Testomny of Arthur A. Hatch, supra n. 64 at 13.
84. Response dated August 12, 1983 to Information Request No. S7.
85. Response dated August 12, 1983 to Information Request No. S8.
86. Id.
87. The study submitted to the Council in April, 1979, merely confirmed the existence of several Massachusetts dams, and verified associated technical data.

Table 10

Eastern Utilities Associates

Hydroelectric Plan

Hydro Site Designation	Annual Deliveries For Blackstone (Mwh)	In-Service Date
Current Sources:		
Tupperware	3,100	1981
Blackstone Falls	3,800	1983
Roosevelt Hydro	3,800	1982
Woonsocket Hydro	1,000	1982
Prospective Company Owned Facility:		
Blackstone Station No. 2	7,000	1984

Source: Forecast, p. II-56.

The Council is on the record as being supportive of the development of capacity and energy from alternative energy source, where that capacity can defer capacity additions, and displace oil in an economically justifiable and environmentally acceptable manner. Thus, the Council's concern from its prior EUA decision still stands and we order the Companies to develop a unified long-range supply plan which includes the aggressive pursuit of renewable energy sources and cogeneration. This issue is addressed in Condition 8.

G. Conclusions

If the Companies planned nuclear additions, including Seabrook Unit II, come on-line as projected, the Companies will experience a short fall in capability responsibility in power years 1987/88 through 1989/90. If the Seabrook Unit II fails to come on-line within the forecast period, reserve requirement deficiencies will occur in 1987/88 through the remainder of the forecast period. The Council finds this unacceptable and has conditioned the Companies to address how they plan to meet these projected shortfalls in their next filing.

The Council has also expressed its concern over the Companies' continued investment in the second unit at Seabrook. While we have nothing conclusive in the record regarding the relative economics of continued investment in Seabrook II for the EUA System, the experience of other investors, and their call for the cancellation of that unit leads the Council to question whether the second unit at Seabrook represents a least cost supply strategy for EUA. Therefore, we condition the Companies to present an analysis of the relative economics of continued investment in Seabrook Unit II versus investments in alternative supply sources including demand mangement strategies.

We have also addressed the issue of conservation and load management in our review of the EUA forecast. We find Eastern Edison's "Teaming Up" proposal acceptable as an initial effort, but are concerned that as of November, 1983 the Company had not begun implementation of the program in its service territory, in spite of the fact that the program was initially proposed in August, 1982. Accordingly, we have ordered the Companies to report to the Council on its progress in implementing the Teaming Up proposal and its plans to monitor and evaluate the programs, consistent with our concerns outlined supra.

We have also found that the Companies have not been yet presented a comprehensive plan for the evaluation and implementatin of all load management strategies available to them, nor have they been aggressive enough in the pursuit of energy from renewable resources and cogeneration. We have accordingly ordered the Companies to address these issues in their next filing.

IV. ORDER AND CONDITIONS

The Council hereby APPROVES the Second Supplement to the Second Long-Range Forecast of the Eastern Utilities Associates subject to the Conditions outlined below. The Companies next Supplement is due on March 31, 1985.

It is hereby ORDERED:

1. That the Companies conduct a literature review on appliance use estimates, and either demonstrate the applicability and superiority of the NEPOOL data in light of that search, or address appropriate changes in the residential data base. The Companies should concentrate their initial efforts on the most energy intensive appliances (ranges, refrigerators, freezers, water heaters, and space heaters).

2. That the Companies perform an aggregate price elasticity of demand study by class of service. The study should include electricity prices, prices of substitute fuels and income. The Companies should attempt to demonstrate the applicability of the NEPOOL elasticities in light of this study or implement appropriate changes.

3. That the Companies state their position regarding the desirability of continued participation in Seabrook Unit II and provide the most recent cost estimates. Also, that EUA provide to the Council with its next filing an analysis of the relative economics of continued investment in Seabrook Unit II versus investments in alternative supply sources, including demand management strategies, renewable energy, and cogeneration.

4. That the Companies submit to the Council a plan that outlines how they plan to meet their capability responsibility in NEPOOL for all years assuming (1) Seabrook Unit I comes on-line in December 1990, and (2) Seabrook II does not come on-line within the forecast period.

5. That the Companies submit a plan for monitoring and evaluating the planned conservation and load management program, which addresses those issues outlined herein.

6. That the Companies provide with its next filing information detailing all measures they have taken to insure that the System is maximizing potential peak reduction from its existing water heater control program. The Companies are also directed to outline the feasibility of its current goal to control all water heaters in all new all-electric homes. The Company should specifically address all issues outlined herein.

7. That the Companies submit to the Council a comprehensive plan for studying the feasibility of implementing direct and indirect load management strategies covering all feasible controllable loads.

8. That the Companies develop a comprehensive and aggressive plan for the development of cost-effective renewables and cogeneration and present this plan to the Council with their next filing.

James G. White, Jr.

James G. White, Jr.

Unanimously APPROVED by the Energy Facilities Siting Council on April 30, 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); Charles DeSaillan (for James S. Hoyte, Secretary of Environmental Affairs); Joellen D'Esti (for Evelyn F. Murphy, Secretary of Environmental Affairs); Ineligible to vote: Dennis J. LaCroix (Public Gas Member).

May 14, 1984
Date

Sharon M. Pollard

Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Colonial Gas Company for Approval of the Second Supplement to its Second Long-Range Forecast of Gas Requirements and Resources: 1983 through 1988	)	Docket No. 83-61

FINAL DECISION

James G. White, Jr.
Hearing Officer
April 30, 1984

On the Decision:
George Aronson,
Director of Technical Analysis

TABLE OF CONTENTS

LIST OF TABLES

The Energy Facilities Siting Council ("Siting Council", or, "the Council") hereby APPROVES conditionally the Second Supplement to the Second Long-Range Forecast of Gas Requirements and Resources for 1983-1988 ("Forecast") of the Colonial Gas Company ("Colonial", or, "the Company").

I. INTRODUCTION

The Colonial Gas Company was formed in 1981 by a merger between the Lowell Gas Company, the Cape Cod Gas Company, and their corporate parent, the Colonial Gas Energy System. Currently, Colonial is a single investor-owned utility that distributes gas in two operating divisions. The Lowell Division ("Lowell") distributes and sells natural gas to approximately 50,000 customers in the City of Lowell and the surrounding towns of Billerica, Chelmsford, Dracut, Dunstable, North Reading, Pepperell, Tewksbury, Tyngsboro, Westford, and Wilmington. The Cape Division ("Cape") serves approximately 38,500 customers in the towns of Barnstable, Bourne, Brewster, Chatham, Dennis, Falmouth, Harwich, Mashpee, Orleans, Sandwich, Wareham and Yarmouth. Cape sells gas primarily to residential customers, while Lowell's gas sales are split more evenly between residential, commercial, industrial and interruptible customers. The two divisions have a total aggregate firm sendout of more than 15,300 million cubic feet (MMcf) per year of gas, making Colonial the fourth largest gas distribution utility in the Commonwealth of Massachusetts. Colonial also has a subsidiary, Transgas Inc., which engages in the transportation of LNG, propane, and other cryogenic fuels.

II. HISTORY OF THE PROCEEDINGS

Colonial filed its Second Supplement on September 30, 1983. Colonial provided public notice of the filing by meeting the Council's publication and posting requirements. The Council received no petitions to intervene. The Council Staff issued a set of Information and Document Requests on November 22, 1983. The Council Staff met in a technical session with Colonial's representatives to discuss these discovery requests. With the exception of one response, Colonial filed responses to the discovery requests on December 30, 1983. Colonial filed the remaining response on January 9, 1983. The Council appreciates Colonial's efforts in filing complete and timely responses.

III. PREVIOUS CONDITIONS

The Siting Council's Decision in review of the Company's First Supplement to the Second Long-Range Forecast of Gas Resources and Requirements ("1982 Forecast"), In Re Colonial Gas Company, 10 DOMSC 1, 58-59 (1983), imposed five Conditions:

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.

The Council is satisfied that the Company has complied with the five Conditions to our last Decision subject to the exceptions and reservations expressed in this Decision. Pursuant to Condition 3, the Company met with Council Staff to discuss incremental forecast improvements. Compliance with Conditions 1, 2, 4 and 5 is discussed in Sections IV.B.2., IV.B.3., VI.B.2., and VI.B.4, infra.

The Siting Council notes that Colonial continues to upgrade its forecasting methodology and to improve the documentation of its judgments and assumptions. The Company has evidently put a good deal of effort into its forecast. The Siting Council encourages the Company to continue to maintain this level of effort in its future filings.

IV. FORECAST OF SENDOUT REQUIREMENTS

A. Description of Forecast Methodology

Colonial produces separate forecasts of sendout requirements for its Cape and Lowell Divisions, but the methodologies used for the two Divisions are similar. Each Division forecasts sendout separately for each of its individual customer classes (and, occasionally, for subclasses or individual large customers), then adds its forecast of sendout for each class to projections of company use and unaccounted-for gas in order to calculate total firm sendout. Both Divisions use the following formula:

$$\text{Seasonal sendout by class}_c = \sum_{\substack{\text{time}\\\text{interval}\\ i}} \left[(BF_i \times NC_i) + (HF_{ic} \times NC_i \times DD_{ic}) \right]$$

where

- BF_i = Base use (in Mcf) per customer over the time interval i ("base factor");
- NC_i = Number of customers in the customer class over the time interval i ;
- HF_{ic} = Heating use (in Mcf) per customer per degree-day over the time interval i under weather condition c ("heating factor");
- DD_{ic} = Heating degree-days over the time interval i under weather condition c;
- i = Time interval (Cape uses seasonal intervals, and Lowell uses monthly intervals);
- c = Weather condition (Normal year or design year).

The Cape Division forecasts base factors, heating factors, and number of customers for each class based on its analysis of historical data trends as interpreted using management judgement and experience. For the residential heating class, Cape forecasts that its sendout will increase by 1.7 percent per year. Cape anticipates that the addition of 900 new heating customers per year in 1983-84 and 1984-85, and 750 per year thereafter, will outweigh the impact of declines in heating and base factors caused by customer energy conservation and the penetration of energy-efficient appliances. In addition, Cape forecasts that its residential non-heating class sendout requirements will increase slightly over the forecast period due to twenty net customer additions per year and its efforts to market additional appliances.

For the commercial class, Cape forecasts an annual growth rate of 1.3 percent, which is comparable to the historic five-year average growth rate. The Division states that "expansion of the distribution system into the Town of Sandwich will ... help make these projections attainable" (Forecast at C-18). Cape analyzes monthly data on consumption and the number of customers in order to account for the seasonal population fluctuations in its service territory. Cape forecasts sendout separately for several large customers. It produces separate forecasts of sales to one large commercial customer (the Otis Air Force Base), to the one customer that it classifies as firm industrial (the Cape Cod Hospital), and to one large interruptible customer (an asphalt production plant).

The Lowell Division also forecasts base factors, heating factors and number of customers for each class based on analysis of historical data as interpreted using management judgement and experience. Lowell, however, has a larger and more diverse customer base, and analyzes customer consumption data at a more disaggregated level than the Cape

Division. Lowell identifies two types of residential heating customers: space heating customers and central heating customers. Among its central heating customers, Lowell forecasts sendout separately for its existing residential customers, new homes, new apartments, and new condominiums. Lowell forecasts that it will add a total of 1000-1200 new residential heating services per year, and that its residential heating sendout requirements will increase by approximately one percent per year despite anticipated declines in usage-per-customer of one percent per year from 1982-83 levels due to customer conservation and penetration of energy-efficient appliances.

Lowell produces a combined sendout forecast for its commercial and industrial customers. Lowell, however, analyzes customer usage separately for its three commercial/industrial rate classes (commercial heating, commercial non-heating, and commercial optional), then sums forecasted sendout for each rate class in order to calculate aggregate commercial/industrial sendout. Lowell forecasts that total commercial/industrial sendout will grow by four percent per year based on "historical growth and economic activity in the area" (Forecast at L-17), and "Company sales records" (Information Request LD-6). Aside from its existing firm customers, Lowell anticipates that four large industrial customers currently using alternate fuels will switch to gas if the Massachusetts Department of Public Utilities ("DPU") approves a special rate. Lowell assumes "for the purpose of this forecast ... that such approval will be granted" (Forecast at L-20). Thus, Lowell includes 127.2 MMcf of sendout per year to these customers in its forecast. Finally, Lowell expects to maintain a constant level of sales to its fifteen interruptible customers subject to the continuing availability of excess pipeline gas at a price "competitive with alternate sources of energy" (Forecast at L-22).

Table 1 summarizes the forecasts of normal year sendout requirements by customer class for the Cape and Lowell Divisions for the 1983-84 and 1987-88 split years.

Cape and Lowell use substantially the same data and calculations to forecast both their design year sendout requirements and their normal year sendout requirements. Cape uses the same base factors and numbers of customers in each case, but increases the heating factor for its residential heating class to "the five-year average ... for the month of January" (Forecast at C-30). Lowell uses the same base factors, the same number of customers, and the same heating factors in each case. Both Divisions use the coldest degree-day total recorded since the 1960's as a design year standard, resulting in design year standards of 7403 effective degree-days[1] for Cape and 6808 degree-days for Lowell. In addition, both Divisions adjust company use and unaccounted-for gas to account for increased heating use.

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1. "Effective" degree-days, as used by the Cape Division, take into account wind speed and cloud cover because of Cape Cod's proximity to the ocean. (Forecast at C-5).

TABLE 1

Forecast of Normal Year Sendout by Customer Class
(MMCF)

	1983-84		1987-88	
	Non-heating Season	Heating Season	Non-heating Season	Heating Season
A. Cape Division				
Residential				
With heat	1046	1878	1132	1991
Without heat	84	37	86	38
Commercial	629	950	652	1008
Industrial	17	23	17	23
Company use and unaccounted-for	18	246	19	260
TOTAL FIRM SENDOUT	1794	3134	1906	3320
Interruptible	9	2	9	2
TOTAL SENDOUT	1803	3136	1915	3322
B. Lowell Division				
Residential				
With heat	1748.6	3636.7	1822.5	3794.2
Without heat	73.7	65.9	62.7	55.9
Commercial/Industrial	1446.7	2961.3	1643.1	3465.5
Dual fuel [a]	0.0	60.5	66.7	60.5
Company use and unaccounted-for	(220.3)	628.3	(155.9)	646.2
TOTAL FIRM SENDOUT	3048.7	7352.7	3439.1	8022.3
Interruptible	560.4	122.3	515.9	122.3
TOTAL SENDOUT	3609.1	7475.0	3955.0	8144.6

Source: *Forecast*, Tables G-1 through G-5.

a Includes loads of four dual-fuel customers currently using alternate fuels.

Table 2 summarizes the forecasts of design year sendout requirements for the Cape and Lowell Divisions for the 1983-84 and 1987-88 split years.

To calculate peak day sendout, Cape and Lowell again use the base and heating factors developed during the production of the normal and design year forecasts. Lowell uses its normal year base and heating factors to calculate peak day sendout (adjusted to units of MMcf-per-day), but adjusts its company use and unaccounted-for gas components to estimate actual peak day volume. Lowell then applies a Btu adjustment based on its anticipated mix of supplies for meeting peak day requirements. In its peak day calculations, Cape uses its normal year base factors, its design year residential heating class heating factor, and a judgementally increased commercial class heating factor. Both Cape and Lowell use the coldest degree-day total recorded on an individual day since the 1960's as a peak day standard, resulting in a standard of 77 effective degree-days for Cape, and 67 degree-days for Lowell.

Table 3 summarizes the forecasts of peak day sendout requirements for the Cape and Lowell Divisions for the 1983-84 and 1987-88 split years.

B. Analysis of Forecast Methodology

1. Documentation

The Council commends Colonial for the thoroughness and clarity of its forecast documentation. In its filing, Colonial provides graphs of historical values of important parameters, including the price of gas. Colonial analyzes trends in the data, and describes the judgements used by the Company to interpret these trends. Additionally, Colonial describes the relationships between the variables that are fundamental to the forecast, and provides sample formulas and calculations. The Council appreciates this level of documentation, which satisfies the Council's reviewability[2] requirement.

Although the forecast clearly is reviewable, the Council suggests several improvements for use in future filings. First, though Colonial describes its use of trend analysis, it does not present the relevant summary statistics. The Council could view the Company's judgements with more confidence if the Company provided regression results, confidence intervals, values of the mean and standard deviation for randomly-varying parameters, or other quantitative data that support its judgements. Second, the Company might provide actual data in tabular form for those cases (e.g., base factors by season by class, number of customers per class by time interval) where it uses data at a

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2. The Council's last decision involving Colonial Gas Co. sets forth the Council's review criteria, including reviewability. In Re Colonial Gas Co., 10 DOMSC 1, 5 (1983).

TABLE 2

Forecast of Design Year Sendout
(MMCF)

	1983-84		1987-88	
	Non-heating Season	Heating Season	Non-heating Season	Heating Season
Cape Division	1876	3606	1997	3913
Lowell Division	3190.4	7921.7	3600.7	8650.9

Source: *Forecast*, Tables G-5.

TABLE 3

Forecast of Peak Day Sendout
(MMCF)

	1983-84	1987-88
Cape Division	44.5	48.7
Lowell Division	95.8	105.2

Source: *Forecast*, Tables G-5 and G-23.

different level of disaggregation than is required by the standard EFSC tables. The Siting Council recognizes that the data used in the production of a sendout forecast are voluminous and that Colonial currently performs many of its calculations manually, making data presentation somewhat difficult and time-consuming. The Council, however, suggests that Colonial investigate the potential benefits and costs of using computerized management tools to prepare and document its forecasts for the Council in the future. The Council notes that computerized spreadsheets and databases might be used to simplify the presentation of data, and might be otherwise useful for forecasting (for example, to perform sensitivity studies, or to update the forecast from year to year).

2. The Impact of Price Changes

Condition 1 to our previous Decision required Colonial to monitor the impacts of natural gas price decontrol on its sendout forecast. The Council notes that Colonial has examined the impact of gas price changes on customer usage factors, as evidenced by the inclusion of price data in its forecast documentation, and by its assumption that conservation will continue during the forecast period. The Council commends the Company for taking this step.

Along with its impact on consumption by existing customers, price increases are likely to affect the Company's ability to market gas to new customers, especially now that natural gas has lost much of its price advantage as compared to oil. The marketing strategies of the Cape and Lowell Divisions necessarily differ because of the different economic climates of their service territories. Thus, the Council examines the growth projections of each Division separately in the following sections.

a. Cape Division

The Cape Division forecasts that the majority of its growth will occur in the residential sector. Cape projects the addition of 4050 new residential heating customers by 1987-88, an increase of 14 percent over its 1982-83 total. Few of these additions will occur because of conversion from oil to gas. Instead, Cape states that "over 90% of the new residential heating customers ... are expected to be the result of new construction" (Information Request CD-1).

Cape supports its forecast of residential growth with data and information from the Cape Cod Planning and Economic Development Commission. These data show an average of 2815 new housing starts per year on the Cape based on an analysis of building permit data (Information Request CD-3). Cape goes on to state that "the Division has secured approximately 50% of all new home construction that has occurred within reach of the Gas Distribution network" (Forecast at C-8). Finally, the Cape Division notes its addition of "over 500 new customers in this class as of July 1983" (Forecast at C-8), which lends empirical support to its projections.

The Council notes the particular importance of monitoring these projections in light of the uncertainties associated with gas prices, as well as the Cape's apparent need for new supplies of pipeline gas (See Section VI, infra). The Council is satisfied that Cape is monitoring the status of housing market, and that it has provided a reasonable level of documentation to support its marketing projections.

Moreover, Cape's evidence on housing markets shows that residential construction has historically been a cyclic business (Information Request CD-3, Attachment F, at 15-16). Cape's projections show "slightly better than average growth" in the 1983-84 period, and "a return to normal growth patterns for ... 1985 through 1988" (Forecast at C-8). Both projections are comfortably consistent with the historical data on housing that the Cape Division presents.

The Council does note, however, that housing markets appear to be extremely volatile. It is possible that the number of housing starts, or the percentage of new housing secured by the Division, will diverge significantly from historical trends, with an appreciable impact on the Cape's forecast. For this reason, the Council requests that the Cape Division, in its next forecast, compare its 1983-84 experience in securing new residential heating customers with its experience in previous years. The Council believes this comparison will enable Cape to verify the continued applicability of historical trends for forecasting purposes in the aftermath of price changes, and will instill more confidence in the Cape's use of trend analysis in its forecast of the number of residential heating additions.

b. Lowell Division

The Lowell Division forecasts substantial load growth in both the residential and commercial/industrial sectors.

In the residential sector, Lowell forecasts the addition of approximately 5300 new central heating customers over the forecast period, an increase of 16 percent over the 1982-83 level. Lowell expects over 90 percent of these additions to be the result of new construction. Half of the additions are projected to be single family homes, a third are projected to be condominiums, and the rest are projected to be apartments.

Lowell bases its forecast of residential growth on building permit data and contact with architects and developers that are active in its service territory. Lowell does not present a complete set of raw data from either of these sources. Lowell cites an American Gas Association ("AGA") forecast of pent-up demand for housing, and refers to Lowell's low unemployment rate and "strong industrial growth in the area" as "giving support to continued housing growth" (Forecast at L-4). Finally, Lowell notes its addition of "over 450 new customers in this class as of July, 1983" (Forecast at L-4), which lends empirical support to its projections.

The Council commends the Lowell Division for its disaggregation of new residential additions by type of housing. The Council notes that Lowell, like Cape, has adjusted its forecast of residential additions to account for the cyclic housing market. Unlike Cape, though, Lowell has not presented a comprehensive review of data on housing starts in its service territory, nor has it estimated the share of new construction that it must secure in order to meet its growth projections. The Council could place more confidence in Lowell's forecast of residential load growth if these data were provided. Accordingly, the Council requests Lowell to present these data in its next filing. The forecast could also be improved by a comparative analysis of historical trends in new residential construction and Lowell's market share of that construction with the actual experience in 1983-84. Finally, the Company might consider presentation of regional economic data or indicators to clarify the relationship between the status of the local economy and Lowell's forecast of new residential construction.

In the commercial/industrial sector, Lowell forecasts the net addition of 150 MMcf of load per year after 1984 in its commercial/optional ("CO") rate class. Growth in this class comprises about 86 percent of all of Lowell's commercial/industrial load growth over the forecast period, with new base load accounting for 20 percent of the CO class load growth. Lowell forecasts the addition of 150 MMcf of load in the CO rate class for 1983-84 as well, but this growth only serves to compensate for the loss of five large customers to alternate fuels in 1982-83. Lowell anticipates that four of the lost customers will switch back to gas upon DPU approval of its new C-8 incentive rate for dual fuel customers. Additionally, Lowell forecasts some growth in its Commercial Heat ("C-5") rate class, and forecasts a slight decline in sales to Commercial Nonheat ("C") customers.

Lowell bases its forecast of commercial/industrial growth rates on "historical growth and economic activity in the area" (Forecast at L-17), though it neither presents historical growth data by rate class nor explains why disaggregation by rate class is appropriate to forecast commercial and industrial sendout requirements.

The Council is concerned with Lowell's reliance on historical trends in individual rate classes to forecast commercial/industrial load growth. The Council notes that historical trends are not necessarily indicative of future performance, especially at a time of substantial changes in the natural gas industry and its markets. In particular, the behavior of large individual customers, such as the five that switched from gas to oil during 1982-83, can have a profound impact on historical sendout data for individual years. The linkage between industrial or commercial gas consumption and the cyclic nature of the local and national economies may not be captured by simple trending. Moreover, disaggregation by rate class is not necessarily the most reliable way to forecast commercial/industrial sendout. The Council questions whether the customers within each rate class share enough commonality in their consumption patterns and in their responses to changing economic conditions for a forecast disaggregated by rate class to be reliable. The Lowell Division itself recognizes that structural changes are occurring in its commercial/industrial markets, saying that "Lowell is becoming more of a service and electronic oriented area" (Information Request LD-5). The Council believes that Lowell's commercial/industrial forecast would be more reliable if Lowell specifically documented and accounted for these structural changes through further data disaggregation.

The Council recognizes that data disaggregation may require the expenditure of considerable amounts of time and resources. On the other hand, the Lowell Division is the largest segment of any gas distribution utility in the Commonwealth that submits a joint forecast of commercial and industrial sendout to the Council. Further, commercial/industrial sendout comprised over 43 percent of Lowell's total firm sendout in 1982-83. Given the relative size of the Lowell Division, the importance of its commercial/industrial sector, and the increasingly competitive nature of end-use markets in the wake of natural gas price changes, the Council finds that it is appropriate[3] for Lowell to disaggregate its commercial/industrial sendout forecast at least to the point where it presents separate forecasts of sendout for its commercial customers and its industrial customers. Further disaggregation by Standard Industrial Classification Code ("SIC code") may, in fact, be appropriate, but we cannot make that determination on the basis of the evidence before us in the instant proceeding.

The Council therefore ORDERS the Lowell Division to submit separate forecasts of sendout for its commercial customers and industrial customers in its next forecast. The Division shall distinguish between the commercial and the industrial classes on the basis of SIC codes, or on other such basis as the Division shall select. Lowell shall justify and document its basis for the distinction in its forecast documentation. If the Division chooses to use aggregated data for any of its individual rate classes (e.g., the Commercial Nonheat class), it shall provide historical data to document that consumption levels are stable within that class. Lowell also shall describe the distribution of usage-per-customer among the customers of that class, and shall explain why individual customers within that class whose consumption greatly exceeds the average usage-per-customer for the class as a whole are expected to maintain their consumption at historic levels. The Council Staff is available upon request to discuss the requirements of this Condition, affixed hereto as Condition 1.

3. Peak day forecast

Condition 2 to our last Decision required the Lowell Division to document explicitly the base and heating factors used to produce its peak day forecast. The Council further suggested that "Lowell should also consider the possibility of using an MCF/DD figure higher than the January average" 10 DOMSC 1, 26 (1983).

In the current forecast, Lowell has documented its forecast of peak day sendout to the satisfaction of the Council (Forecast, at L-57 and L-58). Lowell, however, continues to use the same base and heating factors to forecast peak sendout as are used in its forecasts of normal and design year sendout (See Section IV.A., supra).

The Council notes further that Lowell's peak day forecast results, based on base and heating factors derived from billing data, are consistent with analysis of actual sendout data that was provided by the

3. See 10 DOMSC 1, 5 (1983) for a statement of the Council's standard for whether a methodology is "appropriate".

Division (Document Request D-3). Using actual sendout data and degree-day totals for days of 40 degree-days or greater during the 1982-83 heating season, a regression analyis predicts a peak day sendout of 90.6 MMcf, which is consistent with the Lowell Division's predictions after adjustments for load growth and the thermal content of the gas. Likewise, the Council finds consistency between Cape's forecast of peak day sendout, based on billing data, and a regression analysis of actual sendout and degree-day data from the 1982-83 heating season. The Council concludes that Colonial's forecasts of peak day sendout are reasonable for both Divisions, and that the differences in methodology between the two Divisions are appropriate.[4] The Council suggests, however, that Colonial include in its future filings a description of any unusual customer consumption patterns that occur during peak or near-peak weather conditions such as have been reported by other gas distribution utilities in the Commonwealth.[5]

4. Base and heating factors.

In the previous Decision, the Siting Council stated that "given its historical performance, it is far from clear that the trends representing ... 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" (10 DOMSC 1, 21 (1983)). We have also stated our concern that trend analysis obscures the dynamics of the marketplace and relies too heavily on the assumption that past trends will continue unchanged into the future. In Re Boston Gas Company, 9 DOMSC 1, 44 (1982).

In its current forecast, Colonial has documented numerous instances of appropriate uses of judgement in the interpretation of historical trends, which alleviate some of the Council's concerns. Examples worthy of note are: Lowell's disaggregation of its residential sector, with different assumptions of conservation and usage-per-customer for each group; Cape's treatment of base load usage by residential heating and non-heating customers; and Cape's treatment of the seasonal nature of its base load.

Nevertheless, the Council remains wary of reliance on subjective assessments of historical trends. The Council notes, for example, that AGA assumptions about national rates of energy conservation are not necessarily indicative of customer behavior within specific service territories. Moreover, the fact that consumers are purchasing energy-efficient appliances and implementing energy conservation measures does not guarantee that residential usage-per-customer will decrease, just as usage of the latest in conservation practices in

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4 The Council infers that differences in peak day behavior between the Cape and Lowell Divisions may be attributable to differences in the nature of the customers they serve.

5 See e.g. In Re Boston Gas Co., 9 DOMSC 1, 18 (1982).

new construction does not guarantee that the occupants of the newly-constructed buildings will maintain their consumption rates at a constant level. The Council would welcome quantitative evidence that addresses the causal factors that drive customer behavior and consumption decisions. Such evidence might include service territory-specific appliance saturation and usage data, studies of local short and long-run elasticities, or territory-specific data on consumption patterns after the implementation of specific conservation measures.

The Council's aforementioned concerns should not be construed as criticisms, or as an order to undertake specific studies. Overall, the Council believes that Colonial has presented a reliable forecast and has utilized its judgement appropriately to interpret historical data. On the other hand, the Council has suggested areas that the Company may wish to explore for incorporation into its forecasts in the future. Such explorations may be useful for Colonial's review of long-term consumption trends, especially with the appearance of new supply options that require long-term commitments.

C. Summary

Colonial has submitted a thoroughly reviewable forecast of sendout requirements, and has improved both its forecast methodology and the supporting documentation. The Council appreciates these improvements, and is satisfied that Colonial has complied with Conditions 1 and 2 to our previous Decision. The Council looks forward to further refinements in Colonial's methodology and documentation in future years.

The Company has been ORDERED to comply with one Condition in its next forecast concerning separate treatment of industrial and commercial sendout by the Lowell Division. As stated earlier, this Condition is affixed in our Decision and Order as Condition Number 1. The sendout forecast of the Cape Division is approved unconditionally.

V. RESOURCES AND FACILITIES

A. Overview

Colonial's resources and facilities as presented in its Forecast are substantially the same as described in the Council's most recent Decision regarding the Company.[6] The Cape Division is supplied with pipeline gas by the Algonquin Gas Transmission Company ("AGT") under the F-1 and WS-1 contracts. Cape also purchases synthetic natural gas ("SNG-1") from AGT. The Lowell Division is supplied with pipeline gas by the Tennessee Gas Pipeline Company ("TGP") under the CD-6 contract. Lowell also purchases small amounts of natural gas on a best-efforts basis from the Boston Gas Company ("Boston"). This gas is delivered through an interconnection between their distribution systems. Both Cape and Lowell purchase liquefied natural gas ("LNG") from Bay State Gas Company ("Bay State"), and propane as required from a variety of local suppliers to meet heating season requirements. Both divisions inject gas into underground storage during the summer for delivery during the winter. In addition, both divisions own or lease LNG storage and vaporization facilities, propane storage facilities, and propane-air manufacturing facilities in their service territories.

Tables 4, 5 and 6 summarize Colonial's resources and facilities.

B. Changes

Colonial's current Forecast contains several changes in terms of resources and facilities that have occurred since the Council's previous Decision regarding the Company. In particular, the Council notes the potential for new firm pipeline supplies and the changes in the SNG-1 service provided by AGT.

1. F-1: Increases in contract volumes

For the 1983-84 contract year, the Company has negotiated with AGT to increase its maximum annual quantity (MAQ) of gas under Cape's F-1 contract by 115.77 MMcf per year, equivalent to ten additional days of supply at the maximum daily quantity (MDQ) of 11.577 MMcf per day. The Federal Energy Regulatory Commission ("FERC") approved the increase by letter order on September 21, 1983. Cape and AGT are examining the possibility of extending this increase in F-1 volumes through 1989, though the current Forecast does not reflect the extension.

The Council commends the Company's attempts to increase its MAQ of F-1 gas. An increase would help Cape to reduce its dependence on interruptible supplies, the availability of which must be considered uncertain in future years. As shown by Cape's Cost-of-Gas Adjustment Clauses ("CGAC's") submitted to the DPU, the F-1 contract is the Cape's least expensive source of firm gas supplies. Thus, Cape is seeking to

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6. 10 DOMSC 1 (1983). In several instances, the previous Decision was inconsistent in its treatment of MMcf, BBtu and gallons as units. This Decision notes the instances where corrections have been made.

Table 4
Agreements for Gas Supply
(All Quantities in MMCF at 1000 Btu per cubic foot)

Division	Contract	Supplier	MMCF	Transportation	Contract Dates
Cape	F-1	AGT	3126	AGT pipeline	Through 10/89
	WS-1	AGT	293	AGT pipeline	Through 11/89
	SNG-1	AGT	305	AGT pipeline	Through 9/87
	LNG (F=Firm: O=Option)	Bay State	546 F 155 O	Truck or AGT pipeline displacement	4/83 to 3/84
			565 F 161 O		4/84 to 3/85
			584 F 167 O		4/85 to 3/86
			603 F 173 O		4/86 to 3/87
			622 F 179 O		4/87 to 3/88
Lowell	CD-6	TGP	11000[a]	TGP pipeline	Through 11/2000
	LNG	Bay State	600 F 400 O	Truck or Displacement	Through 3/88
	SFR	Boston Gas	100	Interconnection (Best-efforts)	Through 3/84

Source: Forecast, Tables G-24, at C-49 and L-61; Answer to Information Requests LS-1, CS-5.

a At 1000 Btu per cubic foot. Actual AVL is 10732 MMcf at 1025 Btu per cubic foot.

Table 5
Gas Storage Capacity
(MMCF)

Division	Type	Contract	Capacity	Transportation	Contract Dates
Cape	Underground	ST-1	700	AGT pipeline	Through 4/2000
	LNG (Providence)	AGT-LNG	36 42	Truck or AGT pipeline displacement	Through 1986 1987-92
	LNG	-	198	In service area	-
	Propane	-	39	In service area	-
	Propane	At Lowell	41	Truck	1983
Lowell	Underground	Penn-York	2050	TGP pipeline	Through 3/1996
	LNG	-	1158[a]	In service area	-
	Propane	-	192[a]	In service area	-
	Holder tank	-	3	In service area	-

Source: Forecast, Tables G-14 and G-24, at C-33, C-49, L-30, and L-61; Answers to Information Requests CS-6 and LS-6.

a Data cited incorrectly in last year's Decision.

Table 6
Daily Sendout Capacity
(MMCF PER DAY)

Division	Source	Capacity
Cape	F-1	11.6
	ST-F	3.0
	WS-1	4.9
	SNG-1	4.1[a]
	Propane-air	9.7
	LNG Vap.	31.2
	Total	64.5
Lowell	CD-6	35.5
	UGS[b]	16.0
	Propane-air[c]	26.0
	LNG Storage	79.8
	Total	157.3

Source: *Forecast*, Tables G-14, G-23 and G-24 at C-33, C-46, C-49, L-30, L-59, and L-61; Answer to Information Request LS-3d.

a December 16 to February 29 only, through 1987.
b Underground storage service, firm.
c Not including 12.0 MMcf per day unit used as back-up.

replace an interruptible gas source of uncertain long-term availability with a firm gas source, and is doing so in a least-cost fashion.

2. SNG-1: Changes in contract terms

Though Colonial's full SNG-1 contract originally called for annual deliveries of 614.721 MMcf of SNG to the Cape Division, in previous years the Company has negotiated with AGT to reduce its SNG-1 purchases below the full contract quantity because of its high price. As indicated in the Company's CGACs, SNG-1 has been Colonial's most expensive source of gas since 1973. Thus, in 1982, the Company negotiated with AGT to reduce its annual take of SNG-1 to 307 MMCF.

In the spring of 1983, Colonial arranged to extend its reduction in SNG-1 quantities to 305 MMcf per year until the contract expires in 1987. Colonial will continue to receive SNG-1 during each heating season from December 15 until February 28 (or 29) at a rate of 4.071 MMcf per day. After 1987, Colonial states that it will continue to purchase the gas only "if more secure and economical than alternate supplies" (Information Response CS-4).

The Council is pleased that Colonial has extended its reductions in its takes of its highest-cost supply. The reduction in SNG-1 volumes will result in 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 encourages the Company to continue to reduce its obligations for high-cost supplies in order to maximize supply availability and meet sendout requirements in a least-cost fashion.

3. New pipeline supply projects: Trans-Niagara and CONTEAL

Colonial is participating in two projects to increase deliveries of pipeline gas to the Cape Division; the Trans-Niagara project and phase 1A of the CONTEAL project. In addition, Colonial has previously stated its intent to pursue additional pipeline supplies for delivery to its Lowell Division, though it presents no evidence of such action in this Forecast.

The Trans-Niagara project has changed substantially since the Council's last review. Recent regulatory decisions by FERC and the Canadian National Energy Board forced the participants in the Trans-Niagara project to renegotiate the allocation of gas volumes, the pipeline construction plan, and several contractual provisions.[7] The Council realizes that the renegotiations may cause substantial delay in this project, and is monitoring its progress at FERC.

The second project, the so-called "CONTEAL" project, was proposed as an alternative to a Canadian gas import project during hearings at FERC in the summer of 1983. During the settlement negotiations that followed the FERC hearings, Colonial entered into a precedent agreement

7. See In Re Boston Gas Co., 10 DOMSC 278, 315 (1984).

for 912 BBtu per year of gas from the Consolidated Gas Supply Corporation and the National Fuel Gas Supply Corporation, to be be delivered to the Cape Division via the AGT pipeline.[8] FERC proceedings to review the Settlement Agreement among the parties to this part of the Conteal project will begin shortly, with gas scheduled to flow as early as November, 1984. Prices and contract terms, which are subject to FERC approval, have not yet been finalized, and the timing of this project is also subject to considerable uncertainty.

The Council notes Cape's statement that acquisition of gas supplies from CONTEAL and/or Trans-Niagara "would eliminate the need for interruptible supply for the duration of the existing pipeline contract period and allow for reduction of supplemental use" (Forecast, at C-34). Yet, Colonial does not rely on the CONTEAL volumes in its Forecast. In light of the uncertainties surrounding these new projects, we feel the Company has taken a prudent course by not including these supplies in its Forecast.

C. Conservation Programs

Colonial is implementing several steps to assist its customers with energy conservation measures. Both Cape and Lowell actively promote Mass Save energy audits for their customers. Both Divisions provide information conservation to their customers in the form of bill-stuffers, brochures or leaflets. In addition, the Lowell Division assists customers who receive fuel assistance with the implementation of low-cost conservation measures, encourages sales of energy-efficient appliances through its merchandising department, and provides educational materials to local school children.

The Council notes that the Company presented a brief analysis of a demand management program in its 1982 Forecast. Though the Council did not review that analysis in its last Decision, the Council remains interested in the possibility that gas conserved under such a program might help the Company to meet its firm sendout requirements, especially at a time when the Company is pursuing long-term contracts for new gas supplies.

As noted in the recent Boston Gas Decision,[9] the Council evaluates conservation programs as a supply source on the same basis as the Company's other supply sources. However, the Company has not submitted enough information on the record for the Council to fully evaluate the role of conservation programs in the Company's supply plan. In particular, the Council is interested in evaluating the effectiveness of individual conservation programs for reducing requirements at different times of the year and under different temperature conditions, and in examining the potential for savings achievable by specific types of consumers. Though the Company made assumptions on these matters in its 1982 analysis, it has not yet presented a complete assessment of them in detail.

The Council therefore requests that the Company address these issues as it collects data on customer behavior, and as it evaluates its ongoing conservation efforts.

8. Algonquin Gas Transmission Co., (FERC Docket No. CP82-119-004), Certificate Application, Exh. I(v) at 19.
9. 10 DOMSC 278, 316 (1984)

VI. COMPARISON OF RESOURCES AND REQUIREMENTS

In assessing the adequacy of Colonial's resources to meet requirements, the Council must consider the differing characteristics of the Cape and Lowell Divisions. As such, in this section, the Council analyzes each Division separately. The Council examines whether each Division's gas supplies are sufficient to meet its normal and design sendout requirements, and whether its sendout capacity and storage arrangements are sufficient to meet peak day and cold snap requirements. The Council also examines each Division's contingency plans for meeting requirements in the event of a disruption of supplemental supplies.

A. Cape Division

1. Normal Year

In a normal year, the Cape Division must have adequate supplies to meet the requirements of its firm customers. Each summer, the Cape Division fills its storage facilities to capacity in order to be prepared to meet its requirements during the following heating season. In addition, Cape supplies gas to its interruptible customer as available. Table 7 shows the Cape Division's forecast of normal year sendout requirements and sources of gas supply for each non-heating and heating season over the forecast period.

As the Table indicates, the Cape Division anticipates that it will take its full allotments of F-1, WS-1, and SNG-1 gas in each year. Cape forecasts that the amount of propane and LNG taken from storage to meet requirements will increase steadily over the forecast period. Cape plans to steadily increase its purchases of LNG from Bay State over the forecast period. Finally, as a supplement to its firm supplies, Cape projects that it will steadily increase its purchases of propane on the spot market and its purchases of interruptible pipeline gas to refill its storage facilities during the summer.

The Council is concerned with the Cape Division's reliance on interruptible supplies to refill its underground storage facilities under normal weather conditions. Though interruptible pipeline gas historically has been available to the Company during the summer months, there is no guarantee that such supplies will continue to be available through the end of the forecast period.

The Company addresses its reliance on interruptible pipeline supplies to refill storage by stating that it "is actively pursuing negotiations for quantities of gas from [CONTEAL]... . Successful completion of these, and/or Canadian negotiations would eliminate the need for interruptible supply for the duration of the existing pipeline contract period, and allow for reduction of supplemental use" (Forecast at C-34).

The Council notes that successful negotiations to increase Cape's annual contract quantity of F-1 gas by 115 MMcf (See Section V.B.1, supra), along with the availability of 912 BBtu per year of gas

TABLE 7
COMPARISON OF RESOURCES AND REQUIREMENTS
CAPE DIVISION - NORMAL YEAR
(MMCF)

NON-HEATING SEASON

REQUIREMENTS	1983-4	1984-5	1985-6	1986-7	1987-8
Normal Firm sendout	1794	1826	1854	1880	1906
Fuel reimbursement	9	8	7	12	14
UGS refill	184	387	402	352	412
LNG refill	76	76	76	76	76
LPG refill	0	0	25	30	16
Interruptible sendout	9	9	9	9	9
TOTAL	2072	2306	2373	2359	2433

RESOURCES					
AGT F-1	1704	1633	1532	1378	1378
ST-1	138	122	121	189	216
I-1	76	400	550	600	650
Propane from storage	2	2	3	5	6
Spot propane	0	0	25	30	16
LNG from storage	76	73	66	81	91
Bay State LNG	76	76	76	76	76
TOTAL	2072	2306	2373	2359	2433

HEATING SEASON

REQUIREMENTS					
Normal firm sendout	3134	3189	3235	3278	3320
Fuel reimbursement	19	18	15	14	15
LNG refill	522	543	620	700	666
Propane refill	0	0	20	30	40
Interruptible sendout	2	2	2	2	2
TOTAL	3677	3752	3892	4024	4043

RESOURCES					
AGT F-1	1687	1748	1748	1748	1748
ST-1	297	280	231	223	241
WS-1	293	293	293	293	293
SNG-1	305	305	305	305	305
Propane-air	23	30	45	40	50
Spot propane	0	0	20	30	40
LNG from storage	550	553	630	685	700
Bay State LNG	522	543	620	620	666
TOTAL	3677	3752	3892	4024	4043

Source: Forecast, Table G-22 at C-34 to C-40.

from the CONTEAL project, would indeed eliminate the Divisions' reliance on I-1 interruptible pipeline supplies to refill storage during future non-heating seasons. The Council addresses this issue further in its analysis of design year requirements (VI.A.2., infra).

2. Design Year

During a design year, Cape must have additional resources available to meet the additional requirements of its temperature-sensitive customers. Table 8 shows the Cape Division's forecast of additional firm sendout requirements in a design year and the additional resources available for meeting the requirements.

As Table 8 indicates, Cape plans to meet the additional sendout requirements of a design year by taking additional volumes of LNG, propane and ST gas from storage, and by purchasing its full entitlement of optional volumes of LNG from Bay State. Consequently, during the non-heating season that follows a design heating season, the Company increases its need for interruptible supplies to refill its underground storage facilities. Similarly, the Cape relies more on spot purchases of propane or LNG in a design year than in a normal year.

The Council notes that Cape's reliance on spot purchases and interruptible pipeline gas to refill storage is even greater than Table 8 indicates. Tables 7 and 8 assume that 305 MMcf of SNG-1 are available to meet sendout requirements during each normal heating season over the forecast period. However, Cape's contract for SNG-1 supplies expires in 1987, and other gas utilities in the Commonwealth have forecasted that they will not take their allotment of SNG-1 during the 1987-88 heating season.[10] The Council questions whether the SNG production facility will continue to operate after 1987, and notes that the Cape Division might need to replace the 305 MMcf of SNG-1 that its Forecast shows to be used during the 1987-88 heating season.

Further, Cape's use of F-1 and WS-1 pipeline supplies is limited by dispatching constraints. For example, Cape's Forecast, which accounts for 1748 MMcf of F-1 gas per heating season, assumes implicitly that Cape will take its full MDQ of F-1 gas every day during the heating season.[11] However, on days during the shoulder months when daily sendout requirements are less than the MDQ of F-1 gas (20 actual days during 1982-83), or on days between December 16 and February 29 when daily sendout requirements are less than the sum of the MDQ's of F-1 and SNG-1 gas (12 actual days during 1982-83),[12] daily supply will exceed daily demand, and Cape will not be able to take its full MDQ of F-1 gas. Unless this gas can be stored, Cape will take less than its anticipated quantities of pipeline gas during the heating season. A design winter is likely to contain at least some days on which available pipeline gas volumes cannot be taken in full, thereby leading to overestimates of the amount of firm pipeline supplies available to meet design requirements and underestimates of the role of spot purchases.

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10. See In Re Boston Gas Company, 10 DOMSC 278, 310, 328 (1984); In Re Fall River Gas Company, 10 DOMSC 165, 172, 175 (1984).
11. The MDQ is 11.6 MMcf per day, and a heating season contains 151 days. 11.6 x 151 = 1748.
12. Derived from data received in response to Document Request D-3.

TABLE 8
COMPARISON OF RESOURCES AND REQUIREMENTS
CAPE DIVISION - DESIGN YEAR
(MMCF)

NON-HEATING SEASON

REQUIREMENTS	1983-4	1984-5	1985-6	1986-7	1987-8
Design firm sendout		1911	1942	1969	1997
(Normal firm sendout)		(1826)	(1854)	(1880)	(1906)
Excess of design over normal		85	88	89	91
Maximum additional storage refill		508	468	513	467
TOTAL ADDITIONAL DESIGN REQUIREMENTS		593	556	602	558
RESOURCES					
Interruptible sendout		9	9	9	9
Spot purchases		584	547	593	549
TOTAL ADDITIONAL DESIGN RESOURCES		593	556	602	558

HEATING SEASON

REQUIREMENTS	1983-4	1984-5	1985-6	1986-7	1987-8
Design firm sendout	3606	3692	3767	3840	3913
(Normal firm sendout)	(3134)	(3189)	(3235)	(3278)	(3320)
Excess of design over normal	472	503	532	562	593
RESOURCES					
AGT ST-firm	156	173	222	230	212
best-efforts	138	107	111	44	16
Stored propane	49	17	14	29	29
Stored LNG	217	210	210	220	171
Bay State LNG	103	107	55	0	59
Interruptible Sendout	2	2	2	2	2
Spot purchases	0	0	29	81	120
TOTAL ADDITIONAL DESIGN RESOURCES	665	616	614	606	609
FIRM TOTAL	527	509	503	481	473

Source: Forecast, Tables G-14, G-22, G-23 and G-24; Answers to Information Requests CS-2, CS-5, CS-6, CS-10, CS-11 and CS-12.

As noted in our discussion of normal year resources and requirements (Section V.A.1., supra), the Cape Division is actively seeking new gas supplies to eliminate its dependence on interruptible pipeline supplies and to reduce its spot purchases. Successful acquisition of the CONTEAL gas and the additional quantities of F-1 gas would go far to satisfy the Council's concerns. To the Council's knowledge, however, neither the CONTEAL project nor the increase in F-1 volumes has been finalized, and both projects are subject to change.

In view of the importance of these supply changes to Cape's supply plan, as well as the Council's concerns with reliance on interruptible pipeline supplies, the Council hereby ORDERS the Cape Division to report in its next forecast on the status of the CONTEAL project and the status of the proposed increase in F-1 volumes. The Cape Division shall describe the status of the regulatory approvals that are required in each case, and shall provide estimates of the on-line dates for each project. In the event that Cape anticipates major delays in the projects, Cape shall discuss its other options for reducing its reliance on interruptible pipeline supplies and spot market purchases, including conservation programs and reductions in its projections of load growth. Alternatively, Cape shall present evidence to support its assumption that interruptible pipeline gas will be available in the required quantities throughout the forecast period. This Condition is affixed as Condition 2.

Regarding spot purchases of propane, the Cape Division presents evidence that it monitors propane markets on a regular basis (Information Request CS-7). The Council discusses Cape's need for spot purchases of propane during extended periods of cold weather in the context of the cold snap analysis (See Section VI.A.4., infra).

3. Peak Day

The Cape Division must have adequate sendout capacity to meet the requirements of its customers on a peak day. Table 9 shows the Cape Divison's peak day sendout requirements and sendout capability.

Table 9

Peak Day Resources and Requirements
Cape Division
(MMCF PER DAY)

Available Resources	64.5
Projected Requirements	
1983-84	44.537
1984-85	45.914
1985-86	46.711
1986-87	47.923
1987-88	48.679

Source: Table 6, supra; Forecast, Table G-5.

The Siting Council finds that the Cape Division has sufficient sendout capability to meet its projected peak day requirements.

4. Cold Snap

The Council has defined a cold snap as a prolonged series of days at or near peak conditions, similar to that experienced in Massachusetts during the 1980-81 heating season. To meet cold snap requirements, a company must demonstrate that it has adequate sendout capacity to meet large daily loads, and adequate resources to maintain high sendout levels, over an extended period of time.

Table 10 shows the Cape Divisions's resources for meeting a cold snap during the 1983-84 and 1987-88 heating seasons. With its storage facilities full, Cape can meet sendout requirements at peak day levels for 13 consecutive days in 1983-84, and almost 10 consecutive days in 1987-88, without replenishing supplemental supplies. Cape states that (Forecast at C-58):

> Since the Division has experienced only one 77 EDD in the past twenty years, it can be seen that this represents the most stringent of situations, and that even under Design Year conditions, supplies will last considerably longer.

Cape goes on to state that (Forecast at C-58):

> ... the Division attempts to schedule monthly deliveries to maintain full supplemental storage quantities during the heating season.

The Council is satisfied that the Cape Division has adequate sendout capacity and resources to meet cold snap requirements.

Table 10
Cold Snap Resources and Requirements
Cape Division
(MMCF)

	1983-84	1987-88
Peak day sendout	44.537	48.679
Pipeline MDQ (F-1, WS-1, ST-1 and SNG-1)	23.534	19.463[a]
Required supplementals	21.003	29.216
Peak propane-air production rate	3.0	4.17[b]
Propane storage capacity	39.0	39.0
Days' propane storage	13 days	9.3 days
Peak LNG vaporization rate	18.0	25.04[b]
LNG storage capacity	234.0	240.0[c]
Days' LNG storage	13 days	9.6 days

Source: Forecast, at C-58 and Table G-5; Table 5, supra.

a. Not including SNG-1 MDQ.
b. Assumes same ratio of LNG vaporization to propane-air production as in 1983-84.
c. Includes additional storage at Providence.

TABLE 11
COMPARISON OF RESOURCES AND REQUIREMENTS
LOWELL DIVISION - NORMAL YEAR
(MMCF)

NON-HEATING SEASON	1983-4	1984-5	1985-6	1986-7	1987-8
REQUIREMENTS					
Normal firm sendout	3048.7	3236.4	3299.5	3367.8	3439.1
Fuel reimbursement	44.2	50.0	50.0	50.0	50.0
TGP storage refill	1385.0	1606.9	1710.0	1766.0	1823.0
LNG storage refill[a]	600.0	787.7	832.6	911.4	1002.3
Propane storage refill	0.0	50.0	50.0	70.0	70.0
Interruptible sendout	560.5	560.5	560.6	560.5	515.9
TOTAL	5638.4	6291.5	6502.7	6725.7	6900.3
RESOURCES					
TGP CD-6	4800.3	5450.1	5661.3	5702.0	5702.0
UGS	44.2	50.0	50.0	50.0	50.0
LNG from storage	193.9	141.4	141.4	141.4	176.0
Bay State LNG	600.0	600.0	600.0	762.3	902.3
Spot propane	0.0	50.0	50.0	70.0	70.0
TOTAL	5638.4	6291.5	6502.7	6725.7	6900.3

HEATING SEASON	1983-4	1984-5	1985-6	1986-7	1987-8
REQUIREMENTS					
Normal sendout	7352.7	7523.2	7690.2	7851.3	8022.3
Fuel reimbursement	72.7	75.0	80.0	82.8	86.2
Interruptible sendout	122.3	122.3	122.3	122.3	121.7
TOTAL	7547.7	7720.5	7892.5	8056.4	8230.2
RESOURCES					
TGP CD-6	5170.0	5270.0	5285.0	5298.0	5298.0
UGS	1556.9	1660.0	1716.0	1773.0	1845.1
Propane-air	48.0	48.0	60.0	72.0	72.0
LNG from storage	721.5	691.2	770.0	826.3	928.0
Bay State LNG	0.0	0.0	0.0	0.0	0.0
Boston Gas Interconnection	51.3	51.3	61.5	87.1	87.1
TOTAL	7547.7	7720.5	7892.5	8056.4	8230.2

Source: Forecast, Table G-22; Answers to Information Requests LS-1 and LS-3.

a Includes liquefaction and purchased LNG.

TABLE 12
COMPARISON OF RESOURCES AND REQUIREMENTS
LOWELL DIVISION - DESIGN YEAR
(MMCF)

NON-HEATING SEASON	1983-4	1984-5	1985-6	1986-7	1987-8
REQUIREMENTS					
Design firm sendout		3382.7	3450.7	3524.1	3600.7
(Normal firm Sendout)		(3236.4)	(3299.5)	(3367.8)	(3439.1)
Excess of design over normal		146.3	151.2	156.3	161.6
Maximum additional storage refill		433.7	463.6	491.1	506.9
TOTAL ADDITIONAL DESIGN REQUIREMENTS		580.0	614.8	647.4	668.5
RESOURCES					
TGP CD-6		251.7	40.7	0	0
Bay State LNG		400.0	400.0	237.7	97.7
Interruptible sendout		560.5	560.5	560.5	515.9
Spot purchases		0.0	0.0	0.0	54.9
TOTAL ADDITIONAL DESIGN RESOURCES		1212.2	1001.2	798.2	668.5

HEATING SEASON	1983-4	1984-5	1985-6	1986-7	1987-8
REQUIREMENTS					
Design firm sendout	7921.7	8107.2	8289.1	8464.7	8650.9
(Normal firm sendout)	(7352.7)	(7523.2)	(7690.2)	(7851.3)	(8022.3)
Excess of design over normal	569.0	584.0	598.9	613.4	628.6
RESOURCES					
TGP CD-6	128.0	28.0	13.0	0.0	0.0
UGS	493.1	390.0	334.0	277.0	204.9
Propane-air[a]	3.0	38.0	36.0	34.0	32.0
LNG from storage	433.7	388.8	310.0	253.7	102.0
Interruptible sendout	122.3	122.3	122.3	122.3	121.7
Spot purchases	0.0	0.0	0.0	0.0	168.0
TOTAL	1180.1	967.1	815.3	687.0	628.6

Source: Forecast, Tables G-14, G-22, G-23 and G-24; Answers to Information Requests LS-1 and LS-3.

a Assumes 41 MMcf owned by Cape Division as of December, 1983.

Moreover, the Council questions the reliability of Lowell's forecast of load growth in the commercial/industrial sector (See Section IV.B.1.b., supra). The Council notes that the forecasted design requirements for 1987-88 include at least 127.2 MMcf of load attributable to four large customers that switched from gas to oil in 1982-83. Conceivably, if gas prices are not competitive with oil in 1987-88, these customers might elect to use oil instead of gas, thereby reducing Lowell's sendout requirements for 1987-88 below the forecasted levels and eliminating part of the projected shortfall. In addition, the Council notes that Lowell's 1983-84 forecast of firm design requirements is 6-8 percent lower than its 1982-83 design forecast. Further reductions in Lowell's forecast of firm design requirements in the future might eliminate the entire shortfall.

The Council notes that Condition 4 to our previous Decision required the Lowell Division to demonstrate the availability of Canadian gas or to indicate alternative plans to meet its future firm design requirements. Lowell has not responded satisfactorily to this Condition in its current filing. In view of Lowell's projected shortfall in 1987-88, and noting Lowell's options for addressing its shortfall, the Council hereby retains Condition 4 from our previous Decision as Condition 3 to this Decision, and hereby ORDERS the Lowell Division in its next Forecast either to demonstrate the availability of additional gas supplies or to indicate alternative plans for meeting future firm design requirements.

3. Peak Day

The Lowell Division must have adequate sendout capacity to meet the requirements of its customers on a peak day. Table 13 shows the Lowell Divison's peak day sendout requirements and sendout capability.

Table 13

Peak Day Resources and Requirements
Lowell Division
(MMCF PER DAY)

Available Resources	157.3
Projected Requirements	
1983-84	95.840
1984-85	98.273
1985-86	100.494
1986-87	102.835
1987-88	105.185

Source: Table 6, supra; Forecast, Table G-5.

The Siting Council finds that the Lowell Division has sufficient sendout capability to meet its projected peak day requirements.

4. Cold Snap

The Council has defined a cold snap as a prolonged series of days at or near peak conditions, similar to that experienced in Massachusetts during the 1980-81 heating season. To meet cold snap requirements, a company must demonstrate that it has adequate sendout capacity to meet large daily loads, and adequate resources to maintain high sendout rates, over an extended period of time. In addition, Condition 5 to the previous Council Decision required Lowell to provide a contingency plan in the event of an unforeseen cessation of supplemental supplies.

Table 14 shows the Lowell Divisions's resources for meeting a cold snap during the 1983-84 and 1987-88 heating seasons. With its storage facilities full, Lowell can meet sendout requirements at peak day levels for three to four consecutive weeks without replenishing supplemental supplies. Lowell states that (Forecast at L-62):

> Since the Division has experienced only one 67 DD ($-2^{o}F$) in the past twenty years, it can be seen that this represents the most stringent of situations and that even under design year conditions supplies would last considerably longer.

The Council notes that the Lowell Division manages its inventories of supplemental supplies quite differently than does the Cape Divison. Cape maintains supplemental storage quantities near capacity by scheduling deliveries of supplies on a monthly basis during the heating season. In contrast, Lowell fills its storage to capacity during the nonheating season, then depends on supplies from its comparatively large storage capacity to meet its requirements through the winter. Lowell's inventories of supplemental supplies decline over the course of the heating season as these supplies are taken from storage to meet requirements.[13] Thus, to properly review Lowell's ability to meet cold snap requirements, the Siting Council must consider the impact of inventory levels that decline steadily over the heating season.

The Lowell Division addresses these concerns in its forecast with a special cold snap analysis. Lowell begins by computing the excess requirements of a cold snap over a normal year for 1983-84 and 1984-85 using actual degree-day data from December 20, 1980 through January 19, 1981, a period that Lowell describes as "one of the coldest periods in this century" (Forecast at L-62). Lowell then compares these excess requirements with the forecasted LNG inventory levels at the end of the heating season. Noting that the projected normal LNG inventories at the end of the 1983-84 (433.7 MMcf) and 1984-85 (388.8 MMcf) heating seasons exceed the projected excess requirements of Lowell's cold snaps for 1983-84 (326.3 MMcf) and 1984-85 (331.0 MMcf), Lowell states that (Forecast at L-62):

> ...the Division would have sufficient supplies to meet a cold snap similar to the one which occurred in December, 1980 and January, 1981.

The Council notes that Lowell's use of storage inventories at the end of the heating season in its cold snap analysis adequately considers the impact of inventory levels that decline steadily over the heating season. The analysis satisfies the requirements of Condition 5 to our previous Decision.

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13. During the 1982-83 heating season, Lowell's inventory of LNG declined steadily from 998.746 MMcf on November 1 to 592.238 MMcf on March 31. See Document Request D-3, Attachment C.

Table 14
Cold Snap Resources and Requirements
Lowell Division
(MMCF)

	1983-84	1987-88
Peak day sendout	95.840	105.185
Pipeline MDQ (CD-6 and firm underground storage return)	51.630	51.630
Required Supplementals	44.210	53.555
Peak LNG vaporization rate	35.810	43.379
LNG storage capacity	1158.	1158.
Days' LNG storage	32 days	27.7 days
Peak LPA production rate	8.400	10.176
Propane Storage capacity	192.	192
Days' propane storage	22.9 days	18.9 days

Source: Forecast, at L-62 and Table G-5; Table 5, supra.

On the other hand, Lowell's analysis only addresses the first two years of the forecast period. By 1987-88, due to forecasted load growth, Lowell anticipates that its inventory of stored LNG at the end of the heating season will be only 102 MMcf (See Table 12, supra). An analysis similar to the one that Lowell presents for 1983-84 and 1984-85 shows that the Division will require gas from sources other than LNG storage to meet excess cold snap requirements during the 1987-88 heating season.

The Council cannot determine from the record whether Lowell will be able to obtain gas from sources other than LNG storage in sufficient quantities to meet its 1987-88 cold snap requirements. The Council notes that some propane will be available from storage. Further, small volumes of gas may be available from Boston Gas through the interconnection. Though these volumes are only available on a best-efforts basis, Boston Gas has provided gas to Lowell on extremely cold days in the past. However, without further information on Lowell's alternatives, the Council cannot rule definitively on Lowell's cold snap analysis for the entire forecast period.

The Council hereby ORDERS the Lowell Division to present a cold snap analysis in its next Forecast for each heating season over the forecast period. If LNG inventories at the end of the heating season are insufficient to cover excess cold snap requirements. Lowell shall describe its use of propane, or other sources of gas supply (including transportation requirements) to supplement LNG inventories during a cold snap. This Condition is affixed hereto as Condition 4.

VII. DECISION AND ORDER

The Council hereby APPROVES subject to CONDITIONS the Second Supplement to the Second Long-Range Forecast of Gas Requirements and Resources of the Colonial Gas Company. In its next Forecast, due August 1, 1984, the Council ORDERS:

1. That the Lowell Division submit separate forecasts of sendout for its commercial customers and industrial customers;

2. That the Cape Division either report on its options for reducing its reliance on interruptible pipeline supplies or present evidence that these supplies will be available throughout the forecast period in the required quantities;

3. That the Lowell Division either demonstrate the availability of additional gas supplies or indicate alternative plans for meeting firm design requirements through the forecast period;

4. That the Lowell Division present a cold snap analysis for each heating season over the forecast period.

James G. White, Jr.

James G. White, Jr.
Hearing Officer

Unanimously APPROVED by the Energy Facilities Siting Council on April 30, 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); Joellen D'Esti (for Evelyn F. Murphy, Secretary of Economic Affairs); Charles DeSaillan (for James S. Hoyte, Secretary of Environmental Affairs); Dennis J. LaCroix (Public Gas Member).

May 14, 1984
Date

Sharon M. Pollard
Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the City of Westfield Gas and Electric Light Department for Approval of the 1983 Supplement to the Second Long-Range Forecast of Gas Requirements and Resources	)	Docket No. 83-26

FINAL DECISION

James G. White, Jr.
Hearing Officer

April 30, 1984

The Energy Facilities Siting Council ("Siting Council") APPROVES the 1983 Supplement[1] to the Second Long-Range Forecast of gas requirements and resources ("Supplement") of the City of Westfield Gas and Electric Light Department ("Westfield"), subject to the CONDITION imposed herein.

I. History of Proceedings

Westfield filed the current supplement on December 9, 1983. Westfield provided public notice of the filing by publication and posting of the Notice of Adjudication. The Siting Council received no intervention petitions. Westfield submitted responses to one set of Document and Information Requests.

II. Background

Westfield is a municipal utility and is the tenth largest natural gas distribution utility in the Commonwealth in terms of annual gas sendout.[2] Westfield primarily provides service to approximately 5800 residential customers, but also serves approximately 500 commercial customers, and smaller numbers of industrial (13) and municipal customers (20). Since its last filing in 1981, Westfield has added approximately 100 residential heating customers, and lost approximately 20 residential non-heat customers. Westfield expects these gradual trends to continue through the 1987-88 split year ("the forecast period"). Westfield has also added a few commercial customers since its last filing and expects to add several new commercial customers each year over the forecast period.

Between the 1981-82, and 1982-83 split years, Westfield experienced a substantial decrease in its industrial sendout, which it attributes to fuel-switching from gas to oil by "a large sector" of those customers. (Forecast Table G-3(B); Response dated March 8, 1984 to Information Requests). Westfield, however, projects a gradual return of those customers to natural gas (one per year) during the forecast period.

Table One Reflects Westfield's sendout projections by class for the 1983-84 and 1987-88 split years.

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1. The Energy Facilities Siting Council's last decision involved the Second Long-Range Forecast. City of Westfield Gas and Electric Light Dept., 8 DOMSC 166 (1982). The current filing in this docket will be deemed to constitute the combined First and Second Supplements.
2. G. Aronson, Report of the Energy Facilities Siting Council, "The Gas Industry in Massachusetts" (March 1983).

Table One
(MMcf)

	1983-84 Non-Heat Season	1983-84 Heating Season	1987-88 Non-Heat Season	1987-88 Heating Season
Residential Heat	156.5	296.8	140.9	266.8
Residential Non-Heat	26.3	27.2	23.6	24.5
Commercial	180.3	235.4	170.2	222.2
Industrial	27.5	32.5	33.1	57.2
Municipal	5.9	11.3	6.5	12.4
Company Use- Unnaccounted	22.9	37.9	24.8	41.1
Total Firm	419.4	641.1	399.1	624.2
Interruptible	20.0	15.0	16.0	11.0
Total	439.4	656.1	415.1	635.2

III. Prior Conditions

In its last decision involving Westfield, the Siting Council imposed a condition that Westfield provide either contractual documentation or a contingency plan for supplying its supplemental gas requirements 8 DOMSC 166 (1982). Westfield complied with this condition on September 1, 1982, by submitting the new amendment to the contract with Bay State Gas Company, discussed *infra*.

IV. Forecast of Sendout

The Siting Council observes that Westfield has taken the commendable step of computerizing its forecast. Although several errors in data were discovered during this review,[3] the Council believes that Westfield's use of its computer to produce a sendout forecast can enhance and expedite future filings. The Council encourages Westfield to continue its work on the computerization process. The Siting Council, however, requests Westfield to submit an expanded narrative description of its methodology.

Westfield's normal non-heating and heating seasons are composed of 1400 degree days and 5072 degree days, representing the arithmetic average of the seasonal degree days since 1970. Westfield uses a design year of 6954 degree days composed of the separate non-heating (1631 DD) and heating seasons (5323 DD) with the highest total of degree days since 1970. The Siting Council finds this approach to be appropriate.[4]

In forecasting sendout requirements, Westfield uses historical data to develop base and heating loads for future years. The base load is derived from sales data for the months of June, July, and August.

3. For example, a data error on industrial sendout for split year 1982-83 was replicated throughout the forecast. Westfield also did not submit projections of peak day sendout.
4. The Siting Council reviews a forecast to determine whether it is reviewable, appropriate, and reliable. The appropriateness is considered relative to the size and resources of the particular company. N. Attleboro Gas Co., 10 DOMSC 159, 160 (1984).

Westfield develops heat load factors for each customer class by subtracting base load from total sendout, and dividing the remainder by the average number of customers and the number of degree days. The projections of heating load are compiled by multiplying projected heating load factors by normalized degree days and the projected number of customers. Base load is added to heating load, yielding total class sendout. The individual customer class projections are summed and added to company use and unaccounted-for projections to derive total firm sendout.

The Siting Council finds that Westfield's methodology is basically sound. Further, Westfield's submission of backup workpapers was helpful to the Council in its review.[5] The Siting Council, however, believes several observations are appropriate. Westfield states that "[t]he human element and the feel for the community remains the thrust of determining our future activity." (Response dated March 8, 1984 to Council Staff's Information Requests). The Siting Council agrees with this statement, and notes that Westfield should demonstrate its use of its intimate knowledge of the community to adjust the output of its methodology in the next filing. For example, Westfield reports the loss of seven of its twenty industrial customers between the 1981-82, and 1982-83 split years. Westfield, however, does not indicate their relative sizes in terms of sendout of the lost versus remaining customers, nor does it document the basis for its assumption that these customers will gradually return to gas at their previous consumption levels. As another example, Westfield reports a delay in the plans of the school department to convert to gas, but again does not explain the impact of this fact on the forecast. The Siting Council encourages Westfield to document to the extent possible its use of its judgement and knowledge of its service territory in future filings.

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

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

Westfield purchases gas under Tennessee's G-6 Rate Schedule pursuant to a contract dated October 9, 1981. The initial termination date of the contract is November 1, 2000 with automatic annual extensions unless cancelled on twelve months written notice of either party. The maximum daily quantity ("MDQ") is 5.079 MMcf. The AVL is 1854 MMcf, representing the MDQ times the days in each year.

Westfield purchases LNG from Bay State Gas Company pursuant to a contract dated October 25, 1978, as amended on August 23, 1982.[6] The

5. In its last filing in Docket No. 81-26, Westfield submitted workpapers for projections in future years in addition to workpapers showing the derivation of heat and base loads, which also were submitted in response to an information request in the current Docket. The Council believes Westfield's future filings would be enhanced by the submission of those additional workpapers submitted in Docket No. 81-26.
6. The amendment between Westfield and Bay State dated June 26, 1981, was superseded by the August 1982 amendment.

contract has an initial expiration date of March 31, 1988, but will continue in effect on a contract-year basis thereafter unless cancelled on twelve months written notice of either party. The August 1982 amendment provides for increased quantities of both firm and optional supplies from Bay State throughout the forecast period as follows (MMBtu):

	Firm	Optional	Total
April to October	4,000	0	4,000
November	0	0	0
December	12,500	0	12,500
January	19,000	3,000	22,000
February	37,500	5,750	43,250
March	0	14,250	14,250
Total	73,000	23,000	96,000

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

Under the Bay State contract, Westfield is obliged to use its best efforts to receive the gas by displacement (pursuant to one hour advance notice from Westfield) through an interconnection between the two Companies on Westfield Street in North Agawam. The contractual maximum hourly rate of delivery by displacement is 50 Mcf. If the gas cannot be delivered by displacement, delivery is accomplished by LNG (or propane at Westfield's option) truck transportation provided by Bay State. Westfield requests truck deliveries on twenty-four hours advance notice, but is constrained to request delivery in full truckloads. Westfield's LNG facility has a design maximum daily sendout of 12 MMcf, which is greater than the total storage capacity of 9.1 MMcf. During the 1982-83 split year, the total LNG sendout from storage was 16.3 MMcf, and the maximum daily sendout was 2.02 MMcf.

Westfield's propane facility has a storage capacity of 8.49 MMcf and a design maximum daily sendout of 1.2 MMcf. During the 1982-83 split year, however, Westfield had no propane sendout. Westfield's current filing indicates no existing propane supply contracts.[7]

VI. Analysis of Requirements and Resources

During normal and design heating seasons, Westfield must meet the requirements of its firm customers.[8] Westfield plans to meet these

7. Westfield's Second Long-Range Forecast filed in Docket No. 81-26 (1981) reveals that Westfield's propane contract expired in 1982. See Forecast, Table G-24.
8. Historically, Westfield sold excess pipeline supplies to Bay State. Westfield, however, no longer sells gas for resale to Bay State. Westfield has only one interruptible customer which does not receive gas on peak days. To the extent possible, Westfield supplies gas during the heating season to this customer. See Response to Information Requests D1 and D2 dated March 8, 1984.

requirements with Tennessee pipeline gas, with Bay State gas delivered at the interconnection with Westfield, and with stored LNG purchased from Bay State.

Tables Two and Three portray Westfield's plans for meeting requirements in normal and design heating seasons. Table Two indicates that, in a normal heating season, Westfield will utilize its firm quantities of Bay State gas but less than the available Tennessee G-6 supplies. Thus, in a design heating season shown on Table Three, Westfield may have available additional Tennessee G-6 volumes (subject to daily contractual delivery constraints), as well as the optional Bay State quantities. The Siting Council notes that Westfield's supply plan as indicated on Table G-22 of the Supplement relies on displacement delivery of 50 percent of the Bay State volumes. Westfield's current filing, however, does not address the reliability of these displacement deliveries. Accordingly, the Siting Council requests Westfield to address the reliability of the displacement deliveries and the level thereof on a seasonal basis in the next Supplement.

Westfield must be prepared to meet the requirements of its firm customers on a peak day and in the event of a prolonged cold snap at near design conditions. Westfield's current filing does not identify the peak day sendout requirements on either Table G-5 or G-23. Therefore, the Council ORDERS Westfield to provide a forecast of peak day sendout in its next filing. (See Condition One).

Westfield's filing indicates on a peak day that the following quantities of gas will be available: 5.079 MMcf of G-6 Tennessee gas; 1.2 MMcf of displacement LNG; 12 MMcf of LNG from storage; and 1.2 MMcf of propane for a total daily sendout capacity of 19.48 MMcf. This total represents the maximum daily sendout assuming best efforts deliveries by Bay State through the interconnection, and LNG deliveries by truck as required to supplement the LNG volumes in storage. The Siting Council is concerned about reliance on a peak day on best efforts deliveries of Bay State gas through the interconnection or by truck. Westfield should provide the basis for its assumption that delivery through the interconnection will indeed be made during periods of extremely cold weather. The Siting Council does not necessarily believe that reliance on 1.2 MMcf of propane on a peak day is unreasonable despite the absence of a propane contract. Westfield, however, should justify this reliance through a detailed discussion of its access to propane supplies (including its communication with suppliers[9]), and the propane storage level at the outset of the heating season.

The Siting Council's concern about Westfield's peak day resources is alleviated partially by Westfield's cold snap analysis. Westfield submitted an analysis of its ability to meet a two week "historical worst case" cold snap similar to the one experienced during the gas supply emergency in December 1980, and January 1981. Westfield

9. Supplement Table G-22 indicates Westfield intends to start each heating season with 3.8 MMcf of stored propane. Westfield did not respond to an information request (S-3) regarding its contacts with propane suppliers.

Table Two
Normal Heating Season
(MMcf)

	83-84	84-85	85-86	86-87	87-88
Requirements					
Firm	743.5	738.7	733.6	728.2	722.5
Interruptible	15.0	14.0	13.0	12.0	11.0
LNG Storage Refill	2.5	0.0	0.0	0.0	0.0
Total	761.0	752.7	746.6	740.2	733.5
Resources					
Tennessee G-6	689.5	683.7	677.6	671.2	664.5
Bay State					
(displacement)	34.5	34.5	34.5	34.5	34.5
(storage)	37.0	34.5	34.5	34.5	34.5
Propane	0.0	0.0	0.0	0.0	0.0
Total	761	752.7	746.6	740.2	733.5

Table Three
Design Heating Season
(MMcf)

	83-84	84-85	85-86	86-87	87-88
Requirements					
Firm Design	817.8	812.6	806.9	801.0	794.8
Firm Normal	743.5	738.7	733.6	728.2	722.5
Excess Required	74.3	73.9	73.3	72.8	72.3
Resources					
Tennessee G-6	82.5	88.3	94.4	100.8	107.5
Bay State					
(Optional)	20.5	23.0	23.0	23.0	23.0
Total Additional Supply Available	103.0	111.3	117.4	123.8	130.5

VII. Decision and Order

The Siting Council APPROVES the 1983 Supplement to the Second Long-Range Forecast of the City of Westfield Gas and Electric Light Department subject to the Department's compliance with the following CONDITION in its next Supplement which is due on September 1, 1984.

1) That the Department provide a forecast of peak day sendout requirements and reflect those requirements in the cold snap analysis.

James G. White, Jr.

James G. White, Jr.

April 30, 1984

Unanimously APPROVED by the Energy Facilities Siting Council on April 30, 1984 by those members and designees present and voting: Chairperson Sharon M. Pollard (Secretary of Energy Resources); Sarah Wald (for Paul W. Gold, Secretary of Consumer Affairs); Joellen D'Esti (for Evelyn F. Murphy, Secretary of Economic Affairs); Charles DeSaillan (for James S. Hoyte, Secretary of Environmental Affairs); Dennis J. LaCroix (Public Gas Member).

Sharon M. Pollard

Sharon M. Pollard
Chairperson

May 14, 1984
Date

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 an Occasional Supplement to the Joint Second Annual Supplement to the Second Long Range Forecast of Gas Requirements and Resources	)	No. 84-25A

FINAL DECISION

James G. White, Jr.
Hearing Officer

On the Decision:

George H. Aronson

The Massachusetts Energy Facilities Siting Council ("Siting Council") hereby APPROVES the petition of the Boston Gas Company and Massachusetts LNG, Inc. ("Boston Gas" or "the Company") for approval of an Occasional Supplement to the Joint Second Annual Supplement to the Second Long Range Forecast of Gas Requirements and Resources ("Occasional Supplement").[1]

I. INTRODUCTION AND HISTORY OF THE PROCEEDINGS

Boston Gas filed the Occasional Supplement with the Siting Council on August 2, 1984, pursuant to Siting Council Rules 67.1(3) and 67.7. Boston Gas filed the Occasional Supplement to obtain approval to construct a new pipeline of approximately 19,000 feet in length with an operating pressure of 200 pounds per square inch gauge ("PSIG") at an estimated cost of 2.25 million dollars. The proposed pipeline is a facility under the Siting Council's jurisdiction by virtue of its proposed length and operating pressure, and therefore requires Siting Council approval prior to construction. Mass. Gen. Laws Ann., Ch. 164, Secs. 69G, 69I. The proposed pipeline will run between existing Company facilities at Commercial Point in Dorchester and the New Boston Generating Facility ("New Boston") of the Boston Edison Company ("Boston Edison") located off Summer Street in South Boston. The pipeline is intended to enable Boston Gas to sell natural gas to Boston Edison for use in generating electricity at New Boston until that facility is converted to coal in 1987-88. After that time, the Company states the proposed pipeline will improve service reliability and allow for load growth in the South Boston area. The Company foresees that the project's cost will be more than covered by reductions in fuel costs for customers of both utilities in the three non-heating seasons before the coal conversion is completed.

Following appropriate notice to the public by Boston Gas, the Siting Council held a Public Informational Hearing at the Tynan Community School in South Boston on August 27, 1984. Anthony DiGiovanni of Boston Gas summarized the proposed project and answered questions raised by residents and local officials. Siting Council Public Labor Member Joseph Joyce, South Boston City Councilman James Kelly, and local residents raised concerns about the construction project.[2] The Siting Council received no intervention petitions.

Boston Gas provided responses to information requests of the Siting Council staff.

1. The Energy Facilities Siting Council ("Siting Council") approved the Second Annual Supplement to the Second Long-Range Forecast in March, 1984. <u>Boston Gas Co.</u>, et al. 10 DOMSC 278 (1984).
2. Mr. Leonard Walsh, a resident of Columbia Road, read a letter seeking clarification of several issues involving the proposed construction process. Boston Gas Company ("Boston Gas") responded to each of his questions in a letter dated August 30, 1984.

II. ANALYSIS OF THE PROPOSED PIPELINE

A. Description of the Proposed Facilities

1. Existing Facilities

Boston Gas currently serves approximately 10,000 customers in South Boston, as well as commercial and industrial customers along Northern Avenue in the so-called "City EDIC" project. The Company serves these customers with a single feed line of its Intermediate Pressure ("IP") distribution system from major Company facilities in Everett and Commercial Point. The IP distribution system, which is pressurized to 12 PSIG in the vicinity of Everett and Commercial Point, experiences pressures as low as 5 PSIG in the South Boston area on cold days. DPU Tr. at 15;[3] Occasional Supplement, "Statement of Need" at 1.

Boston Edison generates electricity at the New Boston generating facility using No. 6 residual fuel oil. New Boston consists of two units with a combined maximum net power rating of 760 Megawatts. Though the facility is currently capable of burning only oil, Boston Edison is proposing to modify the facility to utilize natural gas by April, 1985, and coal by 1988. Occasional Supplement, "Statement of Need" at 1.

Boston Gas states that Boston Edison's requirements for natural gas to fuel the units at New Boston would be "6700 MCFH at a minimum delivery pressure of 50 PSIG." Id. Such a requirement far exceeds the capacity of the existing IP distribution system in the neighborhood of New Boston.

2. The Proposed Pipeline

The proposed pipeline will carry natural gas at 200 PSIG delivery pressure from Boston Gas's existing High Pressure distribution system. The proposed pipeline will have the capacity to deliver natural gas to New Boston at the stated requirements for pressure and daily delivery levels. In addition, the Company plans to install a 12 inch "stub" and regulating installation at the intersection of M and East Fourth Streets, and a second stub at Mt. Vernon Street. These stubs will enable Boston Gas to use the proposed pipeline to reinforce the pressure in its existing IP system in the future. DPU Tr. at 17; Occasional Supplement, "Description of Proposed Project" at 1.

The pipeline will originate at the Company's Commercial Point facility at Victory Road in Dorchester. It will head north across the Dorchester Bay Basin to property of the Metropolitan District Commission ("MDC") on the east side of William T. Morrissey Boulevard. The pipeline will then run northeast and east parallel to William J. Day Boulevard, staying off the travelled roadway except for intersecting

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3. The Massachusetts Department of Public Utilities ("DPU") approved the Company's proposal by Orders dated August 30, 1984 and September 7, 1984 (DPU Docket Nos. 84-161, 84-161A). The transcript of a DPU Hearing held on August 21, 1984, ("DPU Tr.") is part of this record.

street crossings, to the intersection with M Street.[4] The pipeline turns north on M Street to East First Street, and turns west on East First Street to the entrance of the Boston Edison Facility at the intersection of East First and L Streets. The routing along M Street and East First Street will be within the traveled roadway. Occasional Supplement, "Description of Proposed Project", at 1; and Exhibit A; Response to Staff Information Requests I-1 and I-2.

The total distance will be approximately 600 feet on Boston Gas property, 600 feet across the Dorchester Bay Basin channel, 13,900 feet on MDC property, and 3600 feet on City of Boston streets in South Boston.

Boston Gas estimates that the total construction cost for the pipeline will be approximately 2.25 million dollars.

3. Environmental Impact

The major environmental impacts of the proposed pipeline project will occur during the construction process. The possible impacts cited by the Company include: temporary disruption of paved and unpaved surfaces during excavation of the trench for the pipeline; disruptions to recreation, traffic flow, and parking; noise, dust and emissions from construction equipment; increase in water channel sedimentation and turbidity, or modification of the channel bottom, due to the water crossing at Dorchester Bay Basin; and soil erosion and dust from the excavated "spoil" or from the freshly backfilled trench.[5]

Boston Gas describes in its Occasional Supplement the measures it will take to minimize these environmental impacts. Boston Gas proposes to backfill its excavated trench and repave road surfaces on a daily basis, with only a small hole left open for the next day's work. Construction is scheduled for late fall and early spring to avoid disruption to recreational facilities during the summer. The Company proposes to use calcium chloride, a wetting agent, to minimize dust from the excavation. The Company chose its proposed route to avoid road surfaces for much of its length, thereby minimizing the impact on traffic flow. The Company routed the pipeline in the Dorchester Bay Basin area to avoid any area that could be considered a salt marsh. Moreover, the Company contracted with the New England Aquarium to conduct core samplings and water testing in the area of the proposed water crossing.

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4. Boston Gas originally proposed to cross William J. Day Boulevard northeast of Columbus Park and to follow Columbia Road to the intersection with M Street. This route was amended after discussions with MDC representatives and members of the community. These amendments do not substantially affect the cost, length, or timing of the proposed project. Response to Staff Information Request I-1.
5. Concerns with these and related environmental impacts were voiced by South Boston residents at the Siting Council's Public Informational Hearing in South Boston on August 27, 1984. E.g., Letter of Leonard Walsh, a resident on Columbia Road, dated August 27, 1984.

The test results indicate that concentrations of metals and pesticides/-herbicides do not exceed maximum limits specified by the Environmental Protection Agency. Occasional Supplement, "Environmental Impact Description" at 1-3.

Finally, Boston Gas attributes environmental benefits to the project, stating that the burning of natural gas instead of oil will "...greatly reduce the sulfur emissions from the plant thus improving the air quality in the communities surrounding the plant." Occasional Supplement, "Statement of Benefits" at 3.

B. Analysis of the Proposed Facility

In order to approve an application to construct a facility, the Siting Council must find that the proposal is consistent with its mandate "to provide a necessary energy supply for the commonwealth with a minimum impact on the environment at the lowest possible cost." Mass. Gen. Laws Ann. Ch. 164, Sec. 69H.

In the instant proceeding, Boston Gas readily acknowledges that the proposed facility will serve a customer that has an alternative source of fuel, and that gas service will be provided on an interruptible basis. Thus, the Siting Council must balance considerations of environmental impact and cost in its analysis of the Company's proposal.

1. Environmental Impact Analysis

The Siting Council must determine whether "plans for expansion and construction of the applicant's new facilities are consistent with current health, environmental protection, and resource use and development policies as adopted by the commonwealth." Mass. Gen. Laws Ann., Ch. 164, Sec. 69J.

Also, pursuant to Rule 83.1, the Siting Council has expressly adopted the policies and policy appendix of the Massachusetts Coastal Zone Management Program as part of its test for consistency with the Commonwealth's policies. In this role, the Siting Council must protect the coastal environment from unnecessary intrusion of energy facilities. The majority of the route of the proposed pipeline, including the water crossing of the Dorchester Bay Basin channel, lies within the boundaries of the Massachusetts Coastal Zone.

Regarding the Company's proposals to minimize the environmental impacts of construction (see Section II.A.3, supra,) the Secretary of Environmental Affairs has determined that the project does not require an Environmental Impact Report ("Certificate of the Secretary of Environmental Affairs on Environmental Notification Form", EOEA 5256, dated August 30, 1984). The Coastal Zone Management ("CZM") division of the Executive Office of Environmental Affairs reviewed the impacts of the proposed project, but concluded that "this project is a relatively minor one. We have been assured that the short water crossing will not involve salt marsh areas nor adversely affect recreational boating at the Dorchester Yacht Club." (Memorandum, dated August 6, 1984).

The Siting Council hereby adopts the above-stated determinations of its sister agencies, acknowledges the potential benefits to air quality through reduced sulphur emissions, and finds that the environmental impacts of the proposed project as presented by the Company are minimal and consistent with current policies as adopted by the Commonwealth, including the Coastal Zone Management Program. Nevertheless, the Siting Council urges the Company to take all reasonable measures to reduce the environmental impacts of the construction process, and to be responsive to the concerns of the affected communities and local residents.

2. Cost Analysis

Given the finding that the environmental impact of the project is minimal, the Siting Council determines whether the proposed facility is consistent with its mandate to provide energy for the Commonwealth at the lowest possible cost.

a. The Company's Analysis

Boston Gas submits that its construction cost for the proposed facility will be more than covered by reductions in the cost of gas to its firm customers.

In support, Boston Gas cites the Company's current billing mechanism, approved by the Department of Public Utilities ("DPU"), that flows all margins on interruptible sales back to firm customers through a reduction in the monthly cost of gas adjustment factor. In this way, sales from Boston Gas to Boston Edison at a price above the cost of gas benefit firm customers by reducing rates.

The actual margins are calculated from formulas defined in the contract between Boston Gas and Boston Edison, dated July 27, 1984, as amended on August 9, 1984 ("contract"). The contract defines "the alternate fuel oil cost" as an average cost per barrel of 2.2% sulphur No. 6 fuel oil as purchased at New Boston (or Boston Edison's Mystic Station) and adjusted for average thermal content. The "reference price" is 90 percent of the alternate fuel oil cost. The "cost of gas" is the weighted average commodity cost of gas on the day of sale from the Company's pipeline gas suppliers. The "transportation charge" is set at $0.15 per MMBtu.

The contract defines two pricing formulas. If the sum of the cost of gas and the transportation charge is less than the reference price, the contract sets the price at the reference price less a discount factor.[6] In this event, Boston Edison is obligated to purchase all the

6. The discount factor itself has two definitions. Until Boston Gas and Boston Edison recover their investments, the discount factor is the reference price less the cost of gas less the transportation charge, then multiplied by the ratio of Boston Edison's investment in the project to the sum of Boston Edison's investment and Boston Gas's investment. After the investments are recovered, the ratio of investments is replaced by 50 percent, thereby splitting the margin equally between Boston Edison and Boston Gas.

natural gas necessary to meet its daily fuel requirements subject to availability from Boston Gas. If the sum of the cost of gas and the transportation charge is greater than the reference price, the contract sets the price at the sum of the cost of gas and the transportation charge. In this event, Boston Edison has the option to accept gas service at such price, or may suspend its obligation to purchase. Therefore, Boston Edison has no obligation to purchase unless its gas price is less than 90 percent of its alternatve fuel oil costs, and Boston Gas will receive a margin of at least $0.15 per MMBtu (the transportation charge) above its cost of gas on all sales.

Using these pricing formulas, Boston Gas calculated the actual margins that would have been refunded to its firm customers had the first year of service begun on August 1, 1983. This annual margin was calculated as 7.4 million dollars, which is more than three times the pipeline's proposed construction cost. Indeed, Boston Gas's calculations show that its construction cost would have been recovered in less than three months using oil and gas prices in effect during Autumn, 1983, or Spring, 1984. Response to Staff Information Request I-6.

Boston Gas estimates annual gas sales to New Boston over the three-year life of the contract as follows:

Period	Estimated Sales
Apr'85-Oct'85	23.2 TBtu (2 Units Available)
Apr'86-Oct'86	23.2 TBtu (2 Units Available)
Apr'87-Oct'87	11.6 TBtu (1 Unit Available; second out for coal conversion)
TOTAL:	58.0 TBtu

Source: Response to Staff Information Request I-4.

Using this sales estimate and the minimum margin of $0.15 per MMBtu, Boston Gas calculates a minimum value of 8.70 million dollars of margin to be flowed back to its firm customers in the three years covered by the contract. Response to Staff Information Request I-6.

Boston Gas states: "the occurrence of design weather conditions during the peak heating season should have little impact on Boston Gas' current estimates of annual sales to Boston Edison." Response to Staff Information Request I-5.

Finally, Boston Gas states: "The proposed sale of interruptible gas ... could replace nearly 4 million barrels of oil per year or nearly 12 million barrels over the three year term of the contract. Moreover, since much of the oil displaced would be from foreign sources or foreign refineries while the pipeline gas supplies are predominantly of domestic origin, the sale will further reduce the Commonwealth's dependence on imported energy." Occasional Supplement, "Statement of Benefits" at 3.

b. Review of the Company's Analysis

By statute, the Siting Council determines whether "projections...of the capacities for existing and proposed facilities are based on substantially accurate historical information and reasonable projection methods." Mass. Gen. Laws Ann., Ch.164, Sec.69J. In this case, the Siting Council finds that the Company has supported its proposal with substantially accurate historical information by submitting calculations of what the margins would have been had the proposed facilities been in operation as of August 1, 1983. See Section III.B.2.a, supra. To determine whether the Company's projection methods are reasonable, the Siting Council reviews the various factors that might cause actual margins to differ from historical or forecasted margins. Such factors might include: low oil prices in relation to gas prices; lower-than-expected gas availability; lower-than-expected daily fuel requirements by Boston Edison at New Boston; and construction delays.

Boston Gas does not attempt to estimate the lowest level of sales to Boston Edison in the event of low oil prices in relation to gas prices, citing "the high degree of uncertainty that surrounds the forecast of oil and gas prices," and the fact that the contract "provides for rejection of certain volumes of gas made available for sale for economic reasons." Response to Staff Information Request I-5.

Nevertheless, the Siting Council mandate suggests that analysis of the impact of these price relationships is required. Thus, the Siting Council examines the sensitivity of the Company's proposal to these prices with a break-even analysis. Assuming a minimum margin of $0.15 per MMBtu and total construction cost to Boston Gas of 2.25 million dollars, sales under this agreement must exceed 15 TBtu at the minimum margin for firm customers to recover the nominal investment cost. Were margins to average $0.28 per MMBtu, as they did from August, 1983, to July, 1984, the break-even point for sales drops to 8 TBtu. In testimony before the DPU, a Company witness stated his expectation that "the margins would be in the 40 to 50 cents per million Btu range" (DPU Tr. at 30), which yields a break-even range for sales of 4.5-5.6 TBtu. The Siting Council adopts these three values as reasonable low, medium and high forecasts for the margin.

Given expectations regarding margins, one can calculate the amount of gas that Boston Gas needs to have available for sale to New Boston during the three-year contract period in order for the reduction in the cost of gas to firm customers to exceed the project's construction cost. Boston Gas cites three sources of gas available for sale at New Boston. First, Boston Gas expects to have 100-150 BBtu per day of excess gas available from its system supply, including excess firm gas under the F-1, CD-6, and CONTEAL contracts and interruptible supplies under the I-1, I-2, I-6 or R-6 contracts <u>in excess of the amounts the Company currently takes for sale to existing firm and interruptible customers</u>. DPU at 29-30; Responses to Staff Information Requests I-6, I-12 and I-16. In support, Boston Gas states that these estimates reflect actual gas offered to it but not taken during the previous years, and presents evidence that the Company's pipeline suppliers will continue to offer such quantities in the future by virtue of the suppliers' own supply surpluses. Texas Eastern Gas Pipeline Company, "Graphs for Customer

Meeting," August 19-23, 1984; Response to Staff Information Request I-12, "Tennessee Gas Pipeline Company Analysis of Supply and Demand Balances." Should these supplies not be available as anticipated, Boston Gas might be able to obtain spot supplies from its traditional suppliers.[7] Finally, should Boston Gas be unable to obtain sufficient gas from its traditional suppliers, the contract allows Boston Edison to purchase its own gas supplies (and transportation services to Boston Gas's system), at which point Boston Gas will transport the gas to New Boston for a $0.15 per MMBtu transportation fee. Contract, Section 6.F.

The Siting Council believes that the Company has provided sufficient evidence to show that its estimate of a daily sales rate to New Boston of approximately 100 BBtu per day is within the range of reasonable expectations. Combining this estimate of gas availability with the previous values for margins, the Company could reach the break-even point for sales in 150 days at the minimum margin, in 80 days at a $0.28 margin, and in 45-56 days at a $0.40-$0.50 margin.

The Siting Council notes that the number of days of sales required to reach the break-even point is small compared to the 642 days during non-heating seasons between April 1, 1985 and October 31, 1987, or to the 369 days of anticipated high levels of interruptible sales between May 1 and September 30 of the next three years.[8] Though gas and oil prices may fluctuate, the Siting Council believes that it is unlikely that Boston Gas's cost of gas (as computed by the contract formula) will stay above a level fifteen cents less than Boston Edison's alternative fuel oil cost for the vast majority of the next three non-heating seasons, especially given the historical cost advantage of natural gas and the emergence of full-scale competition between the two fuels. The outlook for interruptible pipeline supplies and the provision for contract carriage increase the probability that gas sales will occur at the levels anticipated by the Company. Therefore, the Siting Council finds that the project can be economically justified under reasonable expectations regarding the uncertainty surrounding the relationships between oil and gas prices, and the impacts of gas availability.

The major impact of lower-than-expected daily fuel requirements at New Boston or construction delays would be to reduce the period during which sales could occur under the contract. Construction delays might prevent sales during the summer of 1985. A forced outage at New Boston might prevent sales at any time during the three-year contract period.[9]

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7. For example, Boston Gas can arrange to purchase gas from Tennessee Gas Pipeline Company under its "TEMPRO" special marketing program. Response to Staff Information Request I-15.
8. See Response to Staff Information Request I-10.
9. In its Long-Range Forecast of Electric Power Needs and Requirements, Volume 2, page I-1, dated March 1, 1983, Docket No. 83-12, Boston Edison Company presents historical availability data for the New Boston units. From 1977-1982, New Boston 1 had an average availability of 73.7%, and New Boston 2 had an average availability of 75.6%. Capacity factors are not applicable, because the availability of gas will presumably change the manner in which the New Boston units are dispatched.

On the other hand, contingencies might occur under which the potential for sales might increase (e.g., delays in Boston Edison's coal conversion schedule or a forced outage that reduces gas demand at Boston Edison's Mystic 7 station, which is a large interruptible customer with higher priority service than New Boston). The Siting Council finds that these risks are not sufficient in magnitude to change the reasonableness of the Company's expectations that the project can be economically justified.

The Siting Council therefore finds that the Company's economic projection methods are reasonable.

c. Costs and Benefits for the Commonwealth

As stated previously, the Siting Council's mandate provides for analysis of the cost to the Commonwealth. Thus, the Siting Council considers the full range of costs and benefits associated with the project, as well as those incurred by Boston Gas and its customers.

The major cost of the project aside from Boston Gas's investment is the investment by Boston Edison to enable its New Boston facilities to run on natural gas. The contract contains a preliminary estimate of this investment of 8 million dollars, which was confirmed by a Boston Gas witness before the DPU (DPU Tr. at 50). The total investment must be balanced against the total value to the Commonwealth of burning natural gas instead of oil when gas is less expensive.

Assuming the contract had been effect from August, 1983, through July, 1984, Boston Gas calculates the total margin between the reference price and the cost of gas as 16.8 million dollars for that period - substantially more than the total investment. The Siting Council notes that the same considerations investigated earlier (regarding gas availability, relative gas and oil prices, construction delays, and lower-than-expected gas requirements at New Boston) also apply to considerations of the entire investment, and the Siting Council adopts its earlier findings on these matters without repeating the analysis.

Moreover, the Siting Council finds that the project provides real benefits that are more difficult to quantify, including reductions in sulphur emissions in the area of the plant, diversification of the Commonwealth's fuel mix for production of electricity, and long-term increases in Boston Gas's system reliability in the South Boston area.

Therefore, the Siting Council finds that the proposed project is consistent with the mandate to provide a necessary supply of energy for the Commonwealth at a minimum environmental impact and the lowest possible cost.

III. ALTERNATIVES TO THE PROPOSED FACILITY

The Siting Council's mandate requires companies with construction proposals to consider alternatives to the proposed construction. Mass. Gen. Laws Ann., Ch. 164, Sec. 69I, Rule 82.1. As discussed below, Boston Gas presents three alternatives to the proposed route in its Occasional Supplement.

A. Alternative Route "A" from Commercial Point

In Exhibit D to its Occasional Supplement, Boston Gas presents an alternative route from Commercial Point, Dorchester, to New Boston. This route heads northwest along Freeport Street, north along Dorchester Avenue, east along Mt. Vernon Street, north along Old Colony Avenue, northeast on Dorchester Street, and east along East First Street to Summer Street, where it enters the Boston Edison facility.

This route avoids the need for the pipeline to cross Dorchester Bay Basin channel. However, the estimated cost of this route is 3.2 million dollars, almost a million dollars higher than the proposed route. Moreover, the alternative runs predominately within traveled roadways, which would increase traffic disruptions and impacts on local residents. In addition, the Siting Council has previously found that the environmental impacts of the proposed route, including the channel crossing, are minimal.

The Siting Council finds that the proposed route is superior to Alternative Route "A" from Commercial Point.

B. Alternative Route "B" from Everett

In Exhibit E to its Occasional Supplement, Boston Gas proposes an alternative route "B" that serves New Boston from the Company's facilities in Everett. This route heads south from the Everett facilities along Williams Street and Pearl Street; crosses the Chelsea river at Meridian Street; heads west on Condor Street, south on Border Street, southeast on Maverick Street and Airport Road; then crosses Boston Harbor to Summer Street, where it enters the Boston Edison facility.

This route requires two major harbor crossings. The estimated cost is 10.8 million dollars, almost five times that of the proposed route.

The Siting Council finds that the proposed route is superior to Alternative Route "B".

C. Alternative Route "C" from Everett

In Exhibit E, Boston Gas proposes a second alternative route that serves New Boston from the Company's facilities in Everett, which it calls route "C". This route heads northwest from the Company's facilities in Everett along Rover Street and Dexter Street; crosses the Mystic River at Alford Street; heads south on Alford Street and Rutherford Street; crosses the Charles River at North Washington Street; skirts downtown Boston along Commercial Street and Atlantic Avenue; and crosses Fort Point Channel at Summer Street where it enters the Boston Edison facility.

This route requires three water crossings. Its estimated cost is 7.2 million dollars, more than three times that of the proposed route.

The Siting Council finds that the proposed route is superior to Alternative Route "C".

D. Findings on Alternatives

If the Company is to provide service to Boston Edison at New Boston, it must do so from existing facilities at either Commerical Point or Everett (See Section II.A.1., supra). The Siting Council finds that the Company has met the requirement to consider alternative routes from both Commercial Point and Everett, and that the proposed route is superior to the alternatives considered.

The Siting Council has also found that construction of the facility is consistent with its mandate (See Section II.B.2.c., supra), so that construction is preferable to the option of no construction.

IV. DECISION AND ORDER

Wherefore, for the reasons set forth herein, the Siting Council hereby APPROVES the petition of the Boston Gas Company and Massachusetts LNG, Inc., for Approval of the Occasional Supplement to the Joint Second Supplement to Second Long-Range Forecast of Gas Requirements and Resources.

By James G. White, Jr.

James G. White, Jr.
Hearing Officer

Unanimously APPROVED by the Energy Facilities Siting Council on October 4, 1984 by those members and designees present and voting: Sharon M. Pollard, Chairperson, Joellen D'Esti (for Secretary Evelyn F. Murphy); Sarah Wald (for Secretary Paula W. Gold); Rosemary Allen (for Secretary James S. Hoyte); Robert W. Gillette (Public Environmental Member); Joseph W. Joyce (Public Labor Member); Dennis J. LaCroix (Public Gas Member).

10/15/84
Date

Sharon M. Pollard
Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Commonwealth Gas Company and Hopkinton LNG Corporation for Approval of the First Annual Supplements to the Second Long-Range Forecasts of Gas Requirements and Resources, 1983-1988	Docket No. 83-5 Docket No. 83-6

FINAL DECISION

Hearing Officer
James G. White, Jr.

On the Decision:

Juanita M. Haydel

TABLE OF CONTENTS

I. Introduction

The Energy Facilities Siting Council (the "Siting Council" or the "Council") hereby APPROVES the First Annual Supplements to the Second Long-Range Forecasts of Gas Resources and Requirements ("Supplement" or "Forecast") of Commonwealth Gas Company and Hopkinton LNG Corporation subject to the CONDITIONS discussed herein and set forth in the Council's Order at the conclusion of this Decision.

A. Background

The Commonwealth Gas Company ("Commonwealth" or "Company")[1] is engaged in the distribution and retail sale of natural gas to approximately 200,000 residential, commercial and industrial customers in 51 Massachusetts communities. The Company serves three geographic territories of the state. The larger of the three territories is in Central Massachusetts and includes Worcester, Framingham, Dedham and part of the City of Boston. For forecasting purposes, the Company divides this territory into two areas - the Worcester/Marlboro area and the Framingham/Hyde Park area. The second geographic territory is in Eastern Massachusetts and includes Cambridge and part of the City of Somerville. The third geographic territory is in Southeastern Massachusetts and includes New Bedford, Plymouth, and Fairhaven.

In the 1982/83 split-year, the Company provided firm service to 199,961 customers, 93 percent of which were residential. Firm sales in

1. Commonwealth Gas is a wholly-owned subsidiary of Commonwealth Energy System ("System"), a Massachusetts trust whose principal operating subsidiaries include the Commonwealth Gas Company ("Commonwealth" or "Company"), the Commonwealth Electric Company and the Cambridge Electric Light Company. The System also owns 50 percent of the outstanding common stock of Hopkinton LNG Corp.

1982/83 totalled 30,821 MMcf of which 58 percent were sold to residential customers; 26 percent to commercial customers; and 15 percent to industrial customers. In addition to selling gas on a firm basis, the Company sells gas to approximately 70 customers on an interruptible basis. In the 1982/83 split-year interruptible sales amounted to 7,800 MMcf, or approximately 20 percent of total sendout. Table 1 summarizes Commonwealth's 1982/83 sales statistics.

Hopkinton LNG Corporation ("Hopkinton") is engaged in the operation of LNG facilities located in Hopkinton and Acushnet, Massachusetts. Hopkinton neither owns nor sells any gas of its own but provides natural gas liquefaction, storage and revaporization services exclusively to Commonwealth pursuant to a 25-year contract expiring in January, 1997.

B. History of the Proceedings

Commonwealth and Hopkinton filed their First Annual Supplements to the Second Long-Range Forecasts on September 29, 1983. Commonwealth and Hopkington did not propose any new facilities, as defined in Mass. Gen. Laws Ann. Ch. 164, sec. 69G. Commonwealth and Hopkinton provided public notice of the proceeding by publication in local newspapers and posting in city and town halls. No petitions to intervene were received. Commonwealth submitted complete responses to two sets of Document and Information Requests of the Council Staff.

II. Forecast Of Sendout Requirements

A. Overview

The Company has developed the current forecast using the same basic methodology used in the previous filing, with a few exceptions. See 9 DOMSC at 343 et seq. The most notable exception is that the Company has developed its forecast of sendout requirements on a disaggregated basis

Table 1

Commonwealth Gas Company

Number of Customers and Firm Sendout (MMcf)[1]
1982/83 (Actual)

	Division									
	Worcester		Framingham		Cambridge		New Bedford		Total Company	
Customer Class	Customers	Sendout	Customers	Sendout	Customers	Sendout	Customers	Sendout	Customers	Sendout
Residential										
With heating	47,817	5,991	33,294	4,361	29,905	3,433	35,151	3,443	146,167	17,228
Without heating	6,904	163	6,560	153	14,799	239	10,703	243	38,966	798
Commercial	4,126	3,110	3,349	2,068	2,918	1,481	3,442	1,373	13,835	8,032
Industrial	470	2,766	215	1,006	150	273	158	718	993	4,763
Total Firm	59,317	12,030	43,418	7,588	47,772	5,426	49,454	5,777	199,961	30,821
Interruptible	-	1,451	-	1,469	-	3,204	-	1,716	-	7,840

1. Excludes company use and losses.

in response to Condition 9 in the Council's last decision. 9 DOMSC at 404 (1983). The Company has submitted historical data and forecast data covering the period 1983 to 1988 for each of four divisions - Worcester/ Marlboro, Framingham/Hyde Park, Cambridge/Somerville and New Bedford - as well as the total Company forecast. For each of these four areas, the Company has provided normalized 1982/83 historical data, estimates of existing base use and heating use by class and estimates of future base and heating load additions by class. Additionally, for each division the Company has provided a monthly forecast of normal sendout requirements by class of service and a monthly forecast of design sendout requirements for all classes for the five year forecast period. The Council commends the Company for going beyond the requirements of Condition No. 9.

The forecast documentation has been significantly improved and expanded, allowing the Council to review and understand the methodology more thoroughly. Through the use of computer spreadsheet software, the Company has integrated all elements of its budgeting and forecasting process and, with the exception of the added load projections, the Company has provided documention that possesses a level of detail not often seen in a Massachusetts gas company forecast.[2]

Commonwealth provided the bulk of the documentation in response to Information Requests. The Council believes that its review of future filings would be expedited if the Company provided all relevent documentation and workpapers with its initial filing, in the form of a technical supplement. These supporting documents are an integral part

2. The Company also has improved the documentation of the normalization and peak day methodologies in fulfillment of Conditions 2 and 7 of the Council's previous Decision. 9 DOMSC at 402-403 (1983).

of the forecast and provide the detailed information necessary for a complete understanding and review of the forecast. Accordingly, the Council requests that the Company provide all relevant documentation at the time of the initial petition.[3]

The Company begins its forecasting process by first determining the amount of gas available for commitment to new load. Secondly, the Company normalizes the most recent twelve months of actual sendout data to develop a base for forecasting future sendout requirements.[4] Next, the Company adjusts these monthly base line normalized sendout figures to account for expected conservation, and adds projected new loads to derive the forecast of normal year sendout requirements for the following year. These forecast figures are then adjusted on the basis of weather criteria and heating increments to produce a forecast of design requirements.

The new forecast of normal year requirements is the base for the forecast for the following year. The Company continues in this building-block fashion to produce a monthly five year forecast of sendout requirements under normal and design weather conditions.

The Company projects load additions in a separate process that accounts for the type of new load, the portion of that new load which is

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3. The Company should provide the following documents at the time of its initial Petition: The Added Load Forecast (Exhibit SF-1); Gas Available for Sale (memorandum - Exhibit SF-3); Budget Documentation (Exhibit SF-4, including BUDWOR3, etc.; ALLOCFAC; ADLDWB; and ALD858WB, etc.; W838R, etc.; TOT838RA and TGTMCFRA, AGTMCFRA, CG8388RY and AGTMTORI); Siting Council Documentation (Exhibit SF-4, including SCNAWORSA, etc.); Large Industrial Load Forecast; and the regression results (Exhibit SF-13).
4. Commonwealth prepares its forecast on a budget-year basis (September-August) and later sums the monthly figures to conform with Siting Council's split-year reporting requirements.

base and that which is temperature sensitive, and the time of the year of the new load addition.

In the following discussion, the Council highlights only Commonwealth's improvements to the forecasts methodology as reflected in the current Supplement, and those areas in need of further refinement.

B. Determinants of Future Sendout Requirements

The Company states that the primary determinant of future sendout is the availability of gas from its pipeline suppliers, Tennessee Gas Pipeline Company ("Tennessee") and Algonquin Gas Transmission Company ("Algonquin"). The Company's assumptions regarding the availability of pipeline supplies are discussed infra at 36. Additionally, the Company assumes that it will take advantage of the flexibility recently introduced into Algonquin's SNG tariff, and that gas from the Trans-Niagara Canadian Gas Import Project will be available for the start of the 1986/87 heating season. These issues are discussed herein.

The Company determines the amount of gas available for commitment to new firm load after allowing for design requirements of all firm customers on the system as of June 1983 and for additional fuel gas requirements which would be incurred after a design year. In determining volumes available for sale, the Company allows for the contingency that additional volumes might come back on-line as a result of changes in economic conditions. Commonwealth determined these volumes through an examination of industrial customer consumption histories. An additional volume of gas is set aside to protect against unanticipated sales additions.

The Company states that it will not deplete its present firm gas supply until the end of the 1984/85 budget year in August 1985. At that time sales growth would be limited to selling conserved gas to domestic customers. After new firm supply sources come on-line, such as the Algonquin Project, new loads would be added in the commercial and industrial sectors, as well as the domestic sector. Should new supplies not come on line as projected, the Company would modify its sales strategy to not put itself into an oversold position.[5]

The Company indicates that the price of gas and conservation by existing customers are also determinants of future sendout requirements. The Company assumes that the price of gas will be competitive with No. 2 heating oil. Noting that the energy markets are responding to market imbalances and fundamental changes in the industry, the Company assumes that in the long-run an equilibrium will be reached and that gas prices will be competitive with No. 2 heating oil, but that firm gas will not be competitive with No. 6 oil. The Company also assumes that on an interruptible basis, gas will be competitive with all grades of oil. The Council is satisfied that the Company continues to monitor the anticipated impacts of natural gas decontrol. (See Condition 5, 9 DOMSC 332, 402 (1983)).

C. Normalization and Class Allocation

1. Base Use Factors

The Company normalizes the most recent 12 months of actual sendout data (July 1982 to June 1983) to use as a baseline for the forecast of normal year sendout requirements for the following year. Monthly base use estimates are calculated from the average of July and August

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5. Forecast at 12.

aggregate sendout and monthly base use factors.[6] The "Zinder" base use factors range from a value of 1.0 in July and August to a value of 1.5 in January, February and March. They are intended to correlate base use in July and August to increased use of gas by base load appliances during periods of colder weather.

In the last Decision, the Council expressed concern with Commonwealth's use of the Zinder factors. In summary, the Council noted concern over the timeliness of the data and the applicability of the data to the Company's service territories and to each of its customer classes. The Council directed the Company to develop base use factors specific to its service territory, or to develop a satisfactory plan for developing data necessary for such a task.[7]

In doing preliminary work for the current forecast the Company began the process of developing territory specific base use factors. The Company states that it encountered problems with the project in that the sales data is not "clean", noting that in some instances sales to customers who have converted to heating service are still recorded in the non-heat classification. The Company plans to test whether the factors will be more useful than the Zinder factors.

The Company notes that using present sales data to derive base use factors may not result in more reliable factors than the Zinder factors but states it will continue to investigate ways to improve the

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6. The monthly base use factors are based on a 1957 report by H. Zinder Associates, Inc. (See Criteria for Determining Costs of Gas and Electric Service in Military and Public Housing Projects; Clifford A. Brandt, H. Zinder & Associates, Inc., December, 1957). The factors are based on billing data from four Midwest and Middle Atlantic gas companies for residential cooking and water heating use.
7. Commonwealth Gas Co., 9 DOMSC 332, 346-350 (1983).

reliability of the existing data. This is a long-term project given available resources. The Company also states that sufficient time was not available to develop both a disaggregated forecast and base use factors.

The Council concurs in the decision that of the two tasks the development of a disaggregated sendout forecast was the more beneficial. We are also aware of the potential problems with using sales data to estimate company-specific base use factors. However, the Council continues to have serious concerns regarding the reliability of those base use factors in use by the Company. While the Council does not prescribe a particular methodology, it does require a company to demonstrate that its methodology is based on reasonable statistical projection methods and accurate historical data. Commonwealth has not met this requirement with regard to the Zinder factors. The Company has stated that it intends to refine its base use estimates in the future. Therefore, the Company is ordered to present in its next filing its findings on the base use factors, including all supporting documentation, as far as is practicable. Condition 1 addresses this issue.

2. Weather Data

In determining normal and design year degree day planning criteria and in deriving actual and forecast heating increments, the Company uses a "cutback degree day", a measure of the coldness of weather experienced based on the extent to which the daily mean temperature falls below 59° Farenheit, rather than 65°, as is standard. In this sense, it is cutback from the standard 65° reference. The Council noted its concern with the Company's use of this reference point in its Decision on Commonwealth's previous forecast[8], and ordered the Company to provide additional documentation in support of the "cutback" concept. The Company was directed to demonstrate that the use of the 59° base was more appropriate and reliable than the use of the 65° base. In response, the Company has stated that it is unable to provide any formal support for its use of the 59° base for degree days other than that provided in Docket 82-5.[9] The Company adopted this method several years ago based on judgement and observations of sendout during periods of zero degree days as compared to days with only a few degree days. The Company has no formal studies on the subject. As stated above, the Council cannot prescribe a particular methodology for forecasting future sendout requirements. However, the Council urges the Company to examine the effect of the use of the 59° base on its calculated heating increments in light of our concerns discussed herein and in our last decision. The Council requests Commonwealth to address this concern in its next Supplement.

The Company's normal year planning criterion is based on a 25 year average ending August 1977. The Company plans for 6485 degree days on a 65 degree base or 4817 degree days on a 59 degree base.

For a design year, the degree day criterion is based on actual temperature recorded in Worcester for the period September 1, 1955 through August 31, 1956, the coldest year experienced between 1952-1983. In a design year the Company plans for 7304 degree days on a 65° base, or 5671 degree days on a 59 degree base.

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8. See 9 DOMSC 332, 359-360 (1983).
9. The Company submitted to the Council a presentation given at the N.E. Gas Association Gas Operations School by Tenney Associates. Id.

An analysis of degree day data[10] provided by the Company indicates that in some divisions there is a significant variation in temperature relative to that recorded in Worcester. Daily degree day data indicate that for those two-week periods examined in each month of the heating season, the Framingham area experienced in the range of 1 to 4 percent fewer degree days than Worcester; the Cambridge area experienced in the range of 7 to 10 percent fewer degree days than Worcester; and the New Bedford area experienced in the range of 20 to 22 percent fewer degree days than Worcester. Monthly degree day data from the 1981/82 split-year exhibited similar patterns. On a 59 degree basis the Southborough area recorded 4 percent fewer degree days than Worcester; Cambridge recorded 15 percent fewer degree days than Worcester; New Bedford recorded 30 percent fewer degree days than Worcester; and Plymouth recorded 10 percent fewer degree days than Worcester.

The Company states that it has conducted studies on the difference between the correlation coefficient using divisional sendout and divisional degree day data and divisional sendouts with Worcester degree days. Referencing the heating season regression analysis,[11] the Company notes that in some cases there is a higher correlation coefficient in a given division using Worcester degree days than using the division's degree day data.[12] However, the Council notes that in the majority of instances the correlation coefficient is greater where the division's degree day data is used in place of the Worcester degree day data.

The Council is mindful of the Company's position that to use divisional temperature data would add to the complexity of the

10. Exhibits SF-8 and SF-13.
11. Exhibit SF-13.
12. Responses to Information Request SF2-7 dated July 2, 1984.

forecasting process. The Council, however, is not convinced that using divisional data would not increase significantly the accuracy of the forecast. Accordingly, we urge the Company to examine further the effects of the use of the Worcester temperature data in all divisions on the calculated heating increments and the forecast of sendout requirements. The Council requests Commonwealth to report on its study of weather data in its next filing.

3. Heating Increments

In normalizing actual sendout data Commonwealth derives an estimate of the heating use per degree day for each month of the split-year. The Company divides heating load by the actual number of cutback degree days experienced in the month. In order to verify the heating increments based on monthly data, Commonwealth performs a least squares regression on daily sendout and degree day data for each division for the months of December 1983 through March 1984. The Company uses sendout data from two week periods of very cold weather when no interruptible customers are being served. The Company states that the heating increments derived from monthly data are adjusted based on the heating increments resulting from the regression analyses (the slope of the regression line) and judgement. The heating increments are smoothed so they show a pattern of increase in colder months and decrease in warmer months.

In addition to the adjusting the heating increments, the Company adjusts the June 1982 to July 1983 actual temperature sensitive sendout. The Company recalculates heating load based on the adjusted heating increment and the actual number of cutback degree days experienced. This new heating figure is weather normalized.

In addition to smoothing the spreadsheet heating increments used in normalizing actual sendout data, the Company smooths those heating increments calculated from forecasted sendout. In particular, the heating increments for the shoulder months of May and September in all divisions and forecast years appear to be prone to erratic behavior and require substantial smoothing.

An examination of the heating increments derived by Commonwealth for its four divisions indicate that there are considerable adjustments required to produce a smooth series of heating increments for the year. Of the 15 months of heating increment data examined by the staff,[13] 30 percent required some adjustment. The majority of these adjustments occur in the months of April, May and June in the Framingham, Cambridge and New Bedford service territories. Without a complete analysis of the Company's data and the behavorial characteristics of its customers the Council cannot discern the causes for the irregularities in the calculated heating increments. However, the pattern of the required adjustments suggests two possible causes for the irregularities.

First, the fact that the majority of the required adjustments occur in the three divisions for which the Company substitutes Worcester temperature data for the division's actual temperature data and in those months when the temperature differences between Worcester and the divisions appear to be greatest, suggests that the use of Worcester temperature data in all divisions is causing unexpected patterns in the heating increments.

Secondly, because the majority and largest of the adjustments are required in the shoulder months of April, May and June, the problem of irregular heating increments might result from the use of degree day

13. The Company normalizes two sets of data, one covering the period April 1982 to March 1983 to comply with the 1982/83 split-year as required by the Council; and July 1982 to June 1983 to conform with the Company's internal budgeting process. Hence, there are 15 months of actual calculated heating increments.

data on a 59 degree basis. The irregularities may be the result of the Company's discounting degree days in the warmer months that do contribute to heating load, and thereby allocating the temperature sensitive load to too few degree days, resulting in higher than expected heating increments. In cutting back the standard degree days to a 59 degree basis, the non-heating season months tend to lose proportionately more degree days than the heating season months. For example, in the period July 1982 to June 1983 the number of cutback degree days recorded in the non-heating season was 48 percent fewer than the number of standard degree days recorded; while the number of cutback degree days recorded in the heating season was only 18 percent less than the number of standard degree days recorded. Staff calculations indicate that use of a 65 degree day base in the heating increment calculations results in a smooth series of factors.

Alternately, the Company may be experiencing significant heating load in those months and divisions where the heating increments appear to be abnormally high. One other gas utility speculates that its non-heating customers contribute to heating load in the swing months through "distress" heating, the use of ovens for space heating.[14] In this rate class it reports heating increments which do not display a smooth pattern. Although this company uses a flat base use throughout the year, it observes that its non-heating customers' total usage varies considerably during the year, with the greatest usage relative to the number of degree days occurring in the months of September, May and November.

14. See Essex County Gas Company, Docket No. 83-15, Forecast at 6 and Exhibit 7.

Although the effect on total sendout is small,[15] the Council finds that the arbitrary adjustments to the heating increments and heating load without attempting to explain the causes for the observed trends are unjustified, and expects the Company to address this issue when resources permit.

4. Forecast of Future Requirements

The Company normalizes actual aggregate sendout for the June 1982 to July 1983 period based on the adjusted heating increments and the difference between expected normal degree days and actual degree days experienced. The resulting normalized figures become the base for the forecast of sendout requirements in the following year. The Company allocates the base and heat load to domestic, commercial, municipal and small industrial customers in the same manner as in the previous forecast.[16]

The Company forecasts normal year sendout requirements by reducing normalized sendout by one percent to account for expected conservation, adding or subtracting actual load changes, and adding loads forecasted by the marketing department.

The Company's method for forecasting design requirements differs from that used in the previous filing. Consequently, the Council's concerns with the previous method have been eliminated. The Company calculates a heating increment in each forecast month by dividing the forecast normal heat load (existing heat load plus projected temperature sensitive load additions) by normal cutback degree days. As discussed <u>supra</u> at 15, these forecast heating increments are adjusted in order to

15. Staff calculations indicate that the difference between 1982/83 sendout which is normalized using unadjusted heating increments and 1982/83 sendout which is normalized using adjusted heating increments is 0.1 percent.
16. See Forecast, at 6; 9 DOMSC 332, 350-351 (1983).

smooth them to an expected pattern. Next, the heating increment in each month is multiplied by the variation between the normal and design cutback degree days and the difference is added to the forecast heat load. Forecasted design requirements for the month are the sum of forecasted design base and heat load, large industrial load and company use and losses.[17]

The Company's assumptions regarding future load additons and conservation, as well as the Company's method for adding new load additions, are discussed below.

D. Future Load Additions

1. Overview

The Company projects load additions by customer class and division for each year of the forecast. The marketing department's forecast assumes a continuation of current and recent trends adjusted for known variances. The marketing department periodically conducts interviews with new home builders and developers, large industrial customers and industrial development commissions to gain insight into probable future activity. The Company makes no attempt to predict the effect of economic conditions on sales, but rather relies on the judgement of those involved in the construction trade and industry to predict the effect of economic conditions on their activities and consequently on gas sales.[18]

The Company projects that the forecasted rate of growth for the current budget year will be sustainable for the forecast period, with the exception of the 1984/85 budget year. Significant increases in the

17. Large industrial loads are primarily for process use and are assumed to be the same under design weather conditions as under normal weather conditions.
18. Response to Information Requests SF2-4 dated July 2, 1984.

first year due to known activities of particular customers were smoothed out in the second year if it was expected that the particular customer would not generate the additional volumes of sales in the second year.

The Company determined the first year growth rate could not be sustained throughout the forecast period given existing supply constraints. As a result, Commonwealth plans to curtail new commercial and industrial sales after the 1984/85 budget year until new supplies become available. Gas conserved by all customers during this time period will be resold in the residential sector. The Company forecasts that new commercial and industrial sales will begin in November 1986, when new Canadian supplies are projected to come on-line.

The Company projects it will increase its firm sales slightly over 2 percent per year between the 1983/84 split-year and the 1987/88 split-year on a system-wide basis. The Company projects that the commercial sector will provide the greatest growth. Table 2 summarizes the Company's forecast of normal year requirements.

In projecting the load impact of customer additions, Commonwealth uses a methodology which accounts for the pace at which the marketing department expects to add new load during each split-year. For each month the Company accounts for the change in the number of customers or load of a particular type since the same month in the previous year. In this way the Company accounts for all new customers who are not included in the monthly base-line figure to which new load is added. For example, if a customer is added in October, that part of his load expected to occur from October through March is accounted for in the split-year. In April through September of the next split-year, that customer's monthly requirements are accounted for, although he was actually added in the previous split-year.

Table 2

Commonwealth Gas Company
Forecasted Sendout Requirements
(MMcf)

	1983/84	1987/88	Compound Annual Growth Rate %
Residential	19129	19749	0.80
with heating	18366	19114	1.00
without heating	763	635	(4.49)
Commercial	8630	10104	4.02
Industrial	4847	5436	2.91
Company Use	980	1071	2.24
Total Company	33586	36360	2.00
Interruptible	6332	5863	(1.91)

Source: Forecast Tables G-1 through G-5.

This method of accounting for load impacts increases the accuracy and reliability of the forecast on a monthly and seasonal basis in the initial years of the forecast when added load projections are more accurate and the Company is less able to react to short-term changes in its sendout requirements and supply situation. More importantly, this method increases the reliability of the peak day forecast. The Council commends the Company for increasing the reliability of its forecast through the use of this method.

2. Residential Class

For the residential sector the Company makes projections of the number of Company and dealer conversions from oil to gas and the number of new homes and condominiums to be added in each division and each year of the forecast. The current forecast assumes that approximately 2 percent of the 70,000 known low-use customers and potential new customers situated on Company mains not currently using gas will convert from oil to gas each year.[19] The Company also makes estimates of the normal annual requirements of each type of residential unit added, as well as the split between base load and temperature sensitive load.

In all cases the Company assumed that gas would be utilized for space heating and water heating. The usage figures for new homes have been scaled down from the previous forecast to represent a trend towards smaller homes. The Company further assumes that condominiums will be in the 1000 to 1500 square foot range and consume 130 Mcf per year. The Company based the annual usage estimates on actual experience.[20]

19. Response to Information Request SF2-4 dated July 2, 1984.
20. Response to Information Request SF-2 dated January 31, 1984.

Table 3 summarizes the Company's projections regarding the number of company and dealer conversions and the number of new homes and condominiums added annually in each division and the normal annual load for each type.[21] On a system-wide basis, 58 percent of the units added annually to the residential heating class are conversions of non-heating customers to gas heat service. The remainder of customers added to the residential heating class (42 percent) are due to new construction.

The Company projects the loss of a small amount of base load in the residential class. All net load growth is projected to be temperature sensitive, a trend attributable to the fact that the Company is selling base and heating gas conserved by all existing residential customers primarily as heating gas to new residential customers.

The Council is concerned over the lack of documentation supporting the projections of the number of units added annually of each type in each division. The only information available to the Council on which to evaluate the reliability of the Company's residential load projections are the actual data outlined in Table 3. While this information suggests that the Company's projections are reasonable, the Council is unable to make a finding on the reliability of the added load projections. The Council would find the Company's projections more credible were they supported by an analysis or detailed discussion of economic conditions, building activity, conversion prospects and any other factors likely to influence the Company's ability to market gas to the residential sector in each of its divisions. We take note of the

21. We note several errors and discrepancies in the forecasted numbers of residential heating and non-heating customers as reported in Tables G-1 and G-2. However, these errors and discrepancies do not alter the overall forecast of gas requirements. The Company is aware of the errors and their causes and intends to correct them in its next filing. Response to Information Request SF2-2 dated July 2, 1984.

Table 3
Commonwealth Gas Company

Added Load Forecast
Number of Units Annually[1]
(1984-1988)

Division:	Worcester	Framingham	Cambridge	New Bedford	Total Company	Actual Units Added July 1982-June 1983
Conversions:						
Company	338	198	114	150	800	463
Dealer	117	85	135	217	554	734
					1354	1197
New Customers:						
New Homes	228	203	9	160	600	923
Condominiums	152	132	82	10	376	0
					976	923
Total	835	618	340	537	2330	2120

Annual Usage Figures[2]
(Mcf)

	Worcester	Framingham	Cambridge	New Bedford
Company Conversion	160	160	160	160
Dealer Conversion	150	150	150	140
New Homes	150	150	150	140
Condominiums	130	130	130	120
Base Usage	30	30	30	30

(1) Exhibits SF-1 and SF-4.
(2) Forecast at 12.

documentation of added load projections provided by the Cape divsion of the Colonial Gas Company.[22] The Council expects Commonwealth to provide this type of analysis and discussion in its next filing. Condition 2 addresses this issue.

3. Commercial and Municipal Classes

Commonwealth projects that sales to the commercial and municipal sector will increase at an annual rate of 4 percent, making this sector the fastest growing of the Company's major sectors. Sales to commercial and municipal customers in Cambridge are projected to grow most rapidly, at a rate of 6 percent per year; sales to commercial and municipal customers in the New Bedford area are projected to increase most slowly, at a rate of 2.7 percent per year.

The Company projects commercial and municipal load additions on the basis of volumes added each month of the forecast period in each division. The Company projects that it will add approximately 2500 MMcf of commercial and municipal load during the 1984 through 1988 period.[23] Table 4 summarizes the Company's forecast of commercial and municipal load additions for each calender year of the forecast period.

The Company will cease marketing to new commercial customers during the November 1985 to October 1986 time period due to supply constraints. New commercial sales will begin in November 1986, when new Canadian supplies are expected to become available.

In addition to projecting total volumes to be added the Company estimates the percentage of added volumes which will be base load and the percentage which will be temperature sensitive. For the

22. Colonial Gas Company, Docket No. 83-61, 11 DOMSC __ (1984).
23. This figure represents the annual totals for projected load additions over the forecast period. The actual impact on monthly, seasonal and split-year requirements depends upon the pace at which load is added and the distribution of annual requirements over the year. The Company accounts for these variables as discussed at 17.

Table 4

Commonwealth Gas Company
Commercial and Municipal Load Additions
(MMcf)

	Division				
Calendar Year	Worcester	Framingham	Cambridge	New Bedford	Total
1984	245	134	199	77	655
1985	174	95	135	67	471
1986	71	39	30	10	150
1987	245	134	165	77	621
1988	245	134	165	77	621
Total	980	536	694	308	2518

Source: Exhibit SF-1.

Worcester, Framingham, and Cambridge divisions the Company estimates that on an annual basis 25 percent of the added load will be base load. In the New Bedford area the base portion of added load is estimated to be 15 percent. These figures represent that portion of the total load attributable to such uses as water heating, commercial cooking and clothes drying. Other than to outline the end uses comprising base load, the Company has not documented the source of these base load estimates, nor attempted to explain why the projected load additions are expected to exhibit a markedly different pattern from existing commercial/municipal load. Of total annual sales to commercial and municipal customers in 1982/83, the Company estimated 48 percent to be base load. The Council requests the Company in its next filing to document the source of its estimates for the percentage of new base load and discuss why new base load additions exhibit a different pattern from existing customers' base usage.

The Company has submitted data detailing actual load additions for the period July 1982 through June 1983. These data indicate the Company added 572 MMcf in this time period, a volume 14 percent greater than the average annual volume projected to be added over the forecast period. Additionally, the Company has submitted a tabulation of known 1984 load additions as of January 25, 1984. As of that time, the Company had specified a total of 650 MMcf for 320 projects throughout its service territory. The Company notes, however, that the allocation of gas for known projects change on a daily basis during the year as jobs are delayed or cancelled and as total project requirements are adjusted as building plans are finalized.

Other than this data, the Council has little information on which to assess the reasonableness of the Company's projections. As in the residential sector, the Company has provided little documentation in support of its commercial and municipal load growth projections. The Company has not discussed in either its filing or responses to discovery the regional economic conditions, commercial and municipal conversion prospects, new technologies, demographic information, marketing approaches, and other factors that influence the Company's ability to market gas in the commercial and municipal sectors. The Council could place more faith in the reliability of a forecast which included an analysis or discussion of how such factors influence efforts to market gas to the commercial and municipal sectors. The Council expects the Company to more thoroughly address these issues in its next filing. Condition 2 addresses this issue.

4. Industrial Class

The Company projects industrial load additions on the basis of Mcf added annually. Additionally, the Company conducts interviews with existing large industrial customers to determine their gas requirements for the next 12 to 18 months. Interview responses are based on judgements and assumptions on business conditions and other factors affecting gas requirements.

The Company projects that sendout requirements to the industrial class will increase by 2.9 percent per year between 1983/84 and 1987/88. The majority of this growth will be due to small industrial load additions, estimated to be approximately 480 MMcf over the forecast period. This represents a growth rate of 3.5 percent per year. Additionally, load requirements of existing large industrial customers are projected to increase nearly 7 percent over this same period, representing an annual growth rate of 1.7 percent.

The Worcester and New Bedford divisions are expected to experience the greatest growth in the small industrial sector, projected at 22 percent and 18 percent over the forecast period, respectively. Small industrial loads in Framingham and Cambridge are projected to grow only 4.9 percent and 2.8 percent over the forecast period, respectively.

In addition to projecting total load additions, Commonwealth projects the percentage of total load added which will be base and which will be temperature sensitive. The percentage of industrial base use varies by month for the Worcester, Framingham, and Cambridge divisions based on estimates made for particular customers. New industrial loads added in the New Bedford division are projected to be 90 percent base load.

As in the commercial and residential sectors the Company has provided no documentation in support of its industrial load growth projections such as an analysis or discussions of economic conditions in its service territories, demographic trends, competing fuels, marketing approaches, and other pertinent factors which may influence efforts to market gas in the industrial sector. The Council expects that Commonwealth will more thoroughly address these issues in its next filing. Condition 2 addresses this issue.

E. Conservation

The Company states that one of the primary determinants of future sendout requirements is conservation by existing customers. In this year's forecast the Company has made the same assumption regarding conservation by existing customers as in the previous forecast. The Company has assumed that over the next twenty years there will be a twenty percent reduction in consumption per customer for an average conservation rate of one percent per year. The Company has assumed that customers in all classes conserve at the same rate of one percent per year and that all customers conserve at a consistent pace throughout the year. The Company stated in that Docket that these conservation assumptions were not based on empirical observations, but on judgement and were supported by an American Gas Association Study.[24]

The Council expressed concern with these assumptions in its previous decision.[25] The Council noted skepticism of a conservation estimate which did not recognize different conservation behavior by different customer classes or different conservation behavior in different seasons of the year. The Council stated that it was doubtful that residential customers conserve at the same rate or for the same reasons as commercial or industrial customers and that customers conserve at the same rate during the heating season or on-peak as they conserve during the non-heating season or during the year on average. Accordingly, the Company was directed to actively endeavor to collect and analyze data that will aid in assessing the conservation potential in its service territories.

The Company is implementing a conservation program in compliance with an order of the Massachusetts Department of Public Utilities

24. See "A Survey of Actual and Projected Conservation in the Gas Utility Industry: 1973-1990;" American Gas Association.
25. 9 DOMSC at 371-376 (1983).

(MDPU).[26] The key elements of the Company's program are the implementation of weatherization and conservation measures determined by Mass-Save audits through third-party contractors. The program consists of 5000 free Mass-Save Audits, free weatherization measures, and the sale of low-cost weatherization measures through Company offices. Of the total available funds (approximately $725,000), $500,000 is targeted for conservation measures to low-income gas heating customers, including tenants, who are eligible for fuel assistance funding.

As a requirement of the MDPU order, Commonwealth must monitor the results of the program in order to determine customers' responses to incentives, actual costs and savings from various conservation measures, and the impact of conservation on the Company's costs. The Company plans to establish an extensive data base system and computer programs to monitor and analyze the conservation program.[27] Additionally, the Company has outlined goals to revise further its estimates of conservation potential by class of customer, to separate conservation from the impact of the economy on sales, and to examine conservation behavior patterns on-peak as opposed to patterns during a normal year.[28]

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26. This order concerned the disposition of funds from the Louisiana First Use Tax (LAFUT), a tax imposed for two years on all pipeline companies that used or transported natural gas through Louisiana. Massachusetts and seven other states brought suit challenging the tax. In 1981, the U.S. Supreme Court declared the tax unconstitutional and ordered refunds to each state. By order of the MDPU, the largest share of the tax refund was returned to firm customers of the gas companies in 1981. The rest of the tax was money collected from interruptible customers and was ordered by the MDPU to be returned to the firm customers in the form of expenditures on gas conservation programs. See MDPU 871 (1982) and MDPU 871-G (1983).
27. Responses to Information Requests SF-17 dated January 31, 1984 and SF2-17 dated July 2, 1984.
28. Response to Information Request SF2-17 dated July 2, 1984.

The Council commends the Company's recognition of the importance of these issues. The Council expects that the Company's monitoring plan will address all of the Council's concerns regarding the proposed conservation program,[29] as well as provide a basis for the refinement for the Company's current estimates of conservation potential. We request the Company to update the Council on the status of its conservation information system in its next filing. Condition 3 discusses this issue.

F. Peak Day Forecast

The forecast of peak day requirments for each division and year is based on the highest forecasted monthly heating increment (December and January) and an estimate of the daily base load in the same month. However, so that the forecast peak day heating increment more accurately reflects expected customer consumption behavior on peak, the Company adjusts the forecast monthly heating increment based on a comparison of the historic degree day-sendout relationship for the coldest two week period in January 1983 and the degree day-sendout relationship for the month.[30] The Company assumes that this relationship will hold true in the future. The Company states that the actual temperature sensitivity of peak day load is more likely to approximate that of the colder period than that of the month on average. Accordingly, to each of the forecasted heating increments the Company adds (or subtracts) the difference between the heating increment calculated from the actual

29. 9 DOMSC, 384-388 (1983).
30. The heating increment for the coldest two week period is based on a regression analysis (see Exhibit SF-13), while the monthly heating increment is derived from the spreadsheet data.

coldest two week period in January 1983 and the heating increment resulting from monthly averages.[31]

In the case of Worcester and Framingham, the January 1983 heating increment based on monthly averages is greater than the heating increment based on the coldest two week period in the month. Consequently, the adjustments to the forecast heating increments in these divisions are negative, resulting in a peak day heating increment which is less than the monthly heating increment. The Company has not addressed this fact in its filing. The Council, however, believes this issue warrants examination and justification, and requests the Company to address the negative adjustment to the Worcester and Framingham peak day heating increments in its next filing.

In projecting peak day requirements, the Company uses as its peak day degree day criteria 70 degree days, the actual highest degree day level recorded from 1952-1983, plus one. However, in calculating peak day requirements the Company converts this to a cutback basis, resulting in 64 degree day (59 degree base), consistent with the base upon which the heating increments are calculated.

Commonwealth projects that peak day requirements will increase 2.3 percent per year over the forecast period, a rate of growth faster than that of total sendout requirements. The Company projects that the rate of increase will slow to 1.1 percent per year between 1984/85 and

31. For example, the system-wide heating increment for January 1983 based on monthly figures was 3.81 MMcf per degree day. However, a regression analysis of degree day and sendout data for the coldest two-week period in January 1983 indicates a heating factor of 3.9 MMcf per degree day, a difference of 0.09 MMcf per degree day. The forecast heating increment for January 1985 is 4.05 MMcf per degree day. The Company adds 0.09 to the monthly forecast figure of 4.05, to derive a forecasted peak day heat factor of 4.14 MMcf per degree day.

1986/87, as new commercial and industrial sales are curtailed. The Company forecasts that the Worcester Division will have the fastest growth in peak requirements, projected at 2.8 percent per year.

G. Summary and Conclusions

Commonwealth projects that its firm sendout requirements will increase slightly over 8 percent per year over the forecast period, or at an annual average rate of 2 percent. Heating season firm sendout requirements are forecasted to grow at an average rate of 2.1 percent per year; non-heating season requirements are forecasted to grow at an average rate of 1.7 per year.

On a system-wide basis, temperature sensitive load is projected to grow at an average annual rate of 2.7 percent during the forecast period. During the heating season, temperature sensitive load is projected to grow at an average annual rate of 2.5 percent; during the non-heating season, temperature sensitive load is projected to grow at an average annual rate of 3.9 percent. Of total load added over the forecast period, 75 percent is projected to be temperature sensitive. Base load is projected to grow at an annual average rate of 1.1 percent, at equivalent seasonal rates.

The Council commends Commonwealth for producing a forecast that allows the above type of analysis. The forecasting framework also allows this type of analysis on the basis of sales divisions and customer classes. By producing a monthly forecast that accounts for existing base and heating load, base and heating load additions, base and temperature sensitive load losses due to conservation and other factors, and the distribution of existing and new load across the year, the Company should be able to analyze and understand the behavior of its customer base and the effects of load additions and losses on its annual, seasonal and peak day sendout requirements.

We find that the Company's documentation meets the Council's standard of reviewability, and, with the exception of the added load forecast, that the methodology is appropriate to a utility of Commonwealth's size. However, given that information provided by the Company, we cannot determine whether the load growth projections and the resulting forecast of future requirements are reasonable. We reiterate our concerns over the lack of documentation in support of the added load projections for all classes of customers. Commonwealth's filing should more thoroughly address those issues which will affect its ability to attain its load growth goals. We therefore order the Company to provide in its next filing documentation in support of its added load projections by division and class of service for each year of the forecast period. Condition 2 addresses this issue.

The Company has outlined several goals in the area of sales forecasting and statistical reporting. These include the development of marketing and statistical reporting systems, in addition to the conservation information system, discussed at 29. The type of market data under consideration includes information on commercial and industrial connected load and alternative fuel capability; information on added load and conservation potential by class, division and type (base versus heating); information on potential customers currently not on gas service; and gas and oil price projections, including the ability to run scenarios. The statistical reporting system will provide additional detail and segregation of sales statistics. The system will allow the segregation of added load by class, rate, division and pipeline supplier; base load from heating load; new construction from conversions; existing customers from new customers; residential customers by type of housing; and market share and trend data.

The Company clearly has a strong commitment to the development of detailed information on the characteristics of its customers and on energy use in its service territory and to the upgrading of its analytic capabilities. The Council endorses the Company's actions and goals in these areas. Due to the importance of the Company's efforts in this area, the Council requests the Company to report on the status of these projects in its next filing to the Council. Condition 3 addresses this issue.

III. Resources and Facilities

The Company currently receives the majority of its pipeline natural gas from two major suppliers under four contracts. The Tennessee Gas Pipeline Company provides pipeline natural gas to the Company under the CD-6 rate schedule as well as best-efforts transportation of storage gas in conjunction with the Consolidated Gas Supply Corporation's underground storage service. Algonquin Gas Transmission Company provides pipeline natural gas to the Company under two contracts. The bulk of this supply is provided year-round under the F-1 rate schedule. Firm winter service is provided under Algonquin's WS-1 rate schedule. Additionally, the Company has contracts with Algonquin for the purchase of synthetic natural gas (SNG) during the heating season and firm transportation of underground storage gas. To supplement its winter pipeline supplies, the Company has a contract with Hopkinton LNG Corporation for the liquefaction, storage and vaporization of pipeline natural gas. These agreements, except where noted below, are unchanged from the previous year, and will not be discussed in detail.

Table 5 summarizes the Company's existing gas supply contracts, including information on annual contract quantities, maximum daily quantities (MDQs), transportation arrangements, storage capacities and daily withdrawel entitlements, and contract expiration dates.

The Company projects that there will be no curtailments by either pipeline supplier throughout the forecast period based on discussions with suppliers and the best judgement of Company personnel.

Table 5
Commonwealth Gas Company
Existing Supply Sources

I. PIPELINE SUPPLIES

Supplier	Contract	AVL/ACQ (MMcf)	MDQ (MMcf)	Contract Expiration Date	Transportation
Tennessee	CD-6	16,858	55.4	11/1/2000	Tennessee
Algonquin	F-1	19,165	70.9	10/31/89	Algonquin
Algonquin	WS-1	2137	35.6	11/15/89	Algonquin
Algonquin	SNG-1	3304 (1)	21.9	9/30/87	Algonquin

II. STORAGE AGREEMENTS

Supplier	Contract	Storage Capacity (MMcf)	Daily Withdrawel or Vaporizaion Capacity (MMcf)	Contract Expiration Date	Transportation
A. Underground Storage					
Algonquin (2)	ST-1	600	6.2	4/15/2000	Algonquin
Consolidated (3)		905	8.2	8/2000	Tennessee Best-Efforts
B. LNG Storage (4)					
Hopkinton		3000	100	1/97	(5)
Achusnet		500	30	1/97	(6)

1. The Company has opted to reduce its ACQ by 50 % through the remainder of the forecast period.
2. These volumes are from the Company's F-1 contract.
3. These volumes are from the Company's CD-6 contract.
4. These volumes are from the Company's CD-6 contract.
5. There is no transportation associated with LNG storage in Hopkinton.
6. LNG is transported by truck to Acushnet from Hopkinton before the start of each heating season. There is no transportation associated with the LNG after this point.

A. Proposed Amendments to CD-6 Contract.

Tennessee has recently filed with the Federal Energy Regulatory Commission ("FERC") for revision of its delivery obligations on a daily and annual basis for various customers, including Commonwealth[32] Additionally, Tennessee has requested authorization for the transportation of natural gas on a firm basis for certain of its customers, discussed <u>infra</u> at 41. Tennessee states that its customers' current market requirements differ markedly from those used in establishing annual limitations on the volumes of gas which any customer could purchase from Tennessee under its gas sales agreement.[33] To accomodate its customers' estimates of future sales requirements, Tennessee is requesting changes in its sales certificate authority for service to these customers.

Commonwealth has requested Tennessee to increase the annual volumetric limitation by 1,051,000 Mcf during the heating season, to an annual volume of 17,909,000 Mcf. Additionally, the Company is seeking to increase its MDQ by 7,142 Mcf, to 62,528 Mcf per day. The application is currently pending before FERC.

B. F-1 Contract Amendments

In its recent FERC rate case,[34] Algonquin proposed to increase the annual contract volumes for its customers from the current 270 times the F-1 MDQ to 280 times the MDQ. The proposal was approved for a one-year

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32. Tennessee Gas Pipeline Company, FERC Docket No. CP84-441-000.
33. These AVL's were based on the customers' estimates of their requirements for the twelve-month period commencing with the 1973/74 winter season.
34. Algonquin Gas Transmission Co., FERC Docket No. RP83-44.

2. SNG-1 Contract Extension

The Company has included in its forecast SNG from Algonquin after the expiration of the contract in September 1987. The Company states that due to the uncertainty about the future of the SNG contract, the Company assumes that if Algonquin's customers need the SNG supply, Algonquin would be willing to run the plant.

The Company also states that the CONTEAL Project, discussed <u>infra</u> at 43, provides one of the major alternatives for backing out SNG after 1987. In addition, Commonwealth states that Canadian gas and the associated storage could eliminate altogether the need for SNG. Depending on the outcome of the CONTEAL project, the Canadian project and the SNG contract renegotiation, the Company states that it will revise its sales forecast to reflect the changed supply situation.

The Company is commended for reducing its dependence on SNG, its highest cost supply, and is urged to continue to pursue means to reduce the cost of gas to its customers without impinging on the reliability of its supply.

D. Underground Storage

As discussed previously, the Company has two long-term underground storage contracts. The first, with Algonquin, provides a gross storage volume of 600,000 MMBtu and a maximum daily withdrawal of 6,666 MMBtu. After allowing for fuel gas requirements and shrinkage, this storage service nets Commonwealth a daily supply of 6,233 MMBtu. Algonquin provides transportation of this gas on a firm basis. The second contract, with Consolidated Gas Supply Corporation, provides a gross storage capacity of 905,000 Mcf and a maximum daily withdrawal of 8,227 Mcf. After allowing for fuel gas requirements and shrinkage, this storage service nets Commonwealth a daily supply of 7,858 Mcf. Tennessee provides transportation of this gas on a best- efforts basis.

As discussed supra at 38, Tennessee has canvassed its customers to determine interest in modifying contractual entitlements and obligations. Commonwealth has informed Tennessee of its interest in upgrading its best-efforts storage transportation to a firm basis. Tennessee's ability to expand its system capacity is dependent upon the outcome of proceedings before FERC. Should the proposal be approved, it appears the Company will be able to upgrade its best-efforts storage transportation agreement with Tennessee under favorable terms. Otherwise, the transportation arrangement will remain best-efforts.

E. Propane Plant Retirement

Commonwealth owns two propane-air facilities which are used to supplement gas supplies during periods of peak use. The smaller plant is located in Cambridge and has a storage capacity of 155,000 gallons (14 MMcf). Because of modifications to the Company's distribution system, the effective daily sendout capacity of that plant has been reduced from 7.2 MMcf to 3.6 MMcf per day.

In the previous filing the Company indicated plans to retire the plant after the 1984 heating season, upon the receipt of new Canadian supplies. The Company's current forecast projects plant retirement after the 1986 heating season, consistent with the revised projected commencement date for the Trans-Niagara Project.

F. Boston Gas Storage

In order to increase the available supply of peak shaving gas in the Cambridge area, Commonwealth has contracted with the Boston Gas Company (Boston Gas) for the storage and redelivery of gas by

Boston Gas for the account of Commonwealth. The contract provides that Commonwealth may deliver to Boston Gas in Cambridge a mutually agreable volume, not to exceed the maximum storage quantity, on days when Boston Gas' sendout requirements exceed Boston Gas' daily entitlement from Algonquin. Boston Gas stores the gas for the account of Commonwealth and, at the request of Commonwealth, will redeliver the daily volume in Cambridge.

The maximum quantity stored in a heating season is 50,000 Mcf. The maximum daily quantity which can be redelivered to Commonwealth is 8000 Mcf. The redelivery of this gas is on a best-efforts basis and subject to the sole judgement of Boston Gas that such deliveries will not impair service to its customers.

The most recent contract expired on June 30, 1984. In the past years, however, the two companies have executed the agreement on a short-term basis. The Company has indicated in its forecast that it expects the agreement to be in effect throughout the forecast period.

G. New Supplies

1. Trans-Niagara

The Company is a participant in the proposed Trans-Niagara Canadian Gas Import Project pending at FERC.[37] The Company's filing reflects the January 1983 decision of the Canadian National Energy Board to reduce by half all pending gas export applications, including the Pan Alberta-Algonquin contract. Commonwealth still plans to take only 75

37. Boundary Gas, Inc., et al., Docket Nos. CP81-107-000, et al.

percent of the total contract quantity of Canadian gas during the early years of the project, the minimum quantity that can be taken without incurring take-or-pay penalties. Thus, the Company forecasts that it will be entitled to 3,896 BBtu per year, beginning in November 1986, but take only 2,922 BBtu per year during the forecast period. The Company's daily entitlement is 10,674 MMBtu per day. The Company expects that the associated storage capacity and daily withdrawal entitlement will be one-half that originally proposed, or 1,310,300 MMBtu annually and 13,103 MMBtu per day, respectively.

The Council must question whether the Trans-Niagara project will provide the projected supplies by November 1986. Since Commonwealth filed this Supplement, there have been several developments serving to delay the FERC proceedings including continued negotiation regarding the price of gas imports, and competition regarding pipeline transportation arrangements. Given the present pace of this project, the Council requests Commonwealth to discuss the Trans-Niagara project in depth in its next filing and to adjust the anticipated date of project fruition.

2. CONTEAL

During proceedings before FERC on the Boundary and Trans-Niagara Canadian Gas Projects, two new sources of gas supply for the Northeast emerged. Consolidated Gas Supply Corporation and National Fuel Gas Supply Corporation proposed to sell volumes of domestic natural gas to customers in the northeast United States, including Algonquin Gas Transmission Company, for resale to certain distribution companies including Commonwealth. This proposal is referred to as Phase 1A of the

Boundary Gas Settlement or the CONTEAL Project. The settlement was approved by FERC on June 18, 1984.[38]

The CONTEAL proposal is scheduled to begin November 1, 1984. Beginning at that time, Commonwealth will be entitled to a total of 12,013 MMBtu per day on an interruptible basis (6,620 MMBtu of the Consolidated volumes (F-2) and 5,393 MMBtu of National Fuel volumes (F-3)). On November 1, 1985 the gas will be available on a firm basis. Commonwealth's total entitlement will be the same as during the interruptible phase, although the split between the F-2 and F-3 will change to 6,927 MMBtu of F-2 and 5,086 MMBtu of F-3. On November 1, 1986 Commonwealth's total entitlememnt increases to 13,453 MMBtu per day (10,380 MMBtu of F-2 and 3,073 MMBtu of F-3). The initial expiration date of the current gas supply contracts is 1992.

The Company states that the CONTEAL volumes will be used primarily as a winter season supplemental supply, and will lessen the Company's dependence on Algonquin SNG when that contract expires in September, 1987. At the present time it appears that the commodity rate of the CONTEAL volumes will be competitive enough to be sold on the interruptible market.[39]

IV. Comparison of Resources and Requirements

A. Normal Year

During a normal year the Company must have sufficient resources to meet the requirements of its firm customers, to refill underground and LNG storage before the start of each heating season, and to meet fuel

38. Consolidated Gas Supply Corp. et al., FERC Docket Nos. CP83-403-001, et al.
39. Response to Information Request S2-1 dated July 2, 1984.

requirements for storage injection, withdrawal, transportation and liquefaction.

Tables 6 and 7 summarize the Company's forecast of normal year heating and non-heating season requirements and the resources it expects to use to meet those requirements. Additionally, the Company's forecast of interruptible sales during a normal year is outlined. These Tables have not been adjusted to reflect the CONTEAL project.

As indicated in these Tables, the Company projects that Canadian pipeline supplies will be available for the start of the 1986/87 heating season. Storage facilities are expected to be available for injection beginning with the 1987 non-heating season.

The Company projects the availability of interruptible supplies from Algonquin throughout the forecast period. As previously discussed, and as is indicated by the Tables, if this gas should not be made available, it would have no effect on the Company's firm customers, but would reduce sales to interruptible customers.

The Company also relies on the availability of Consolidated storage return gas, the transportation of which is provided by Tennessee on a best-efforts basis. The Company plans on receiving between 311 and 358 MMcf of Consolidated storage return volumes during a normal heating season. This is equivalent to 34 to 40 percent of gross storage capacity. In the 1981/82 heating season, a period that was 3 percent colder than normal, the Company received slightly over 500 MMcf, or 71 percent of requested volumes. In the 1982/83 heating season, a period 11 percent warmer than normal, the Company received 300 MMcf, or 54 percent of requested volumes. Finally, during the coldest two week periods of the 1981/82 heating season (with an average day of 53 degree days) and 1982/83 (with an average day of 41 degree days) the Company

Table 6
Commonwealth Gas Company
Comparison of Resources and Requirements
Normal Year - Non-Heating Season
(MMcf)

Requirements	1984	1985	1986	1987
Normal Firm Sendout	10720	10962	11027	11189
Fuel Reimbursement	310	374	462	362
Underground Storage Refill	917	945	901	2140
LNG Storage Refill	1742	2108	2610	2040
Interruptible Sendout	4631	4622	4104	5252
Total Requirements	18320	19011	19104	20983
Resources				
AGT F-1	8579	8765	8961	9395
WS-1	159	56	112	327
ST-1	39	39	36	47
Trans-Niagara	0	0	0	1287
Subtotal	8777	8860	9109	11056
TGT CD-6	8663	9259	9168	8993
LNG Storage	230	192	127	234
I-1/I-2	650	700	700	700
Total Resources	18320	19011	19104	20983

Source: Forecast, Tables G-4A, G-5, G-22A,B.

Table 7
Commonwealth Gas Company
Comparison of Resources and Requirements
Normal Year - Heating Season
(MMcf)

Requirements	1984-85	1985-86	1986-87	1987-88
Normal Firm Sendout	23680	24133	24343	25171
Fuel Reimbursement	50	48	44	104
Interruptible Sendout	431	441	541	611
Total Requirements	24161	24622	24928	25886
Resources				
AGT F-1	10117	10062	9611	9288
WS-1	2044	1988	1773	1784
ST-1	555	551	480	351
SNG	1634	1634	1634	1656
Trans-Niagara	0	0	1584	1594
Trans-Niagara Storage	0	0	0	1121
Subtotal	14350	14235	15082	15794
TGT CD-6	7501	7562	7581	7669
Storage	350	311	326	358
Subtotal	7851	7873	7907	8027
LNG Storage	1960	2514	1939	2065
Total Resources	24161	24622	24928	25886

Source: Forecast, Tables G-4A, G-5, G-22A,B.

received 51 and 55 percent of requested volumes, respectively. Tennessee returned full volumes requested by Commonwealth on approximately 57 percent of the days in the two winter periods.[40]

Based on this historical data, the Company's projections of storage volumes returned in a normal heating season appear reasonable. Moreover, given Commonwealth's projections of its customers' requirements and available supplies, the Council is satisfied that the Company has sufficient resources to meet its requirements in a normal year.

B. Design Year

During design weather conditions the Company must have sufficient resources in excess of its normal year supplies to meet the additional requirements of its temperature sensitive customers. The Company must also have sufficient resources to meet additional fuel requirements incurred due to increased use of underground and LNG storage gas and to refill underground and LNG storage used to meet heating season design requirements.

In order to meet additional requirements during design conditions Commonwealth has several options. It can take quantities of pipeline supplies above its normal take, up to contract limitations, use additional quantities of underground and LNG storage, produce propane air, and divert interruptible sendout to firm customers.

The method by which the Company actually meets design sendout requirements depends on a number of factors. The ability to take above normal quantities of pipeline gas depends on the pattern of daily dispatching over the course of the year. If daily pipeline entitlements

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40. Response to Information Requests S-12 dated January 31, 1984.

exceed daily demand, gas which can not be stored for later use must be turned away. In this case, the Company may not receive its full annual contract quantity. The availability of storage gas depends on transportation arrangements. The transportation of underground storage by Tennessee is on a best-efforts basis, and can not be relied on during periods of peak-like weather. The ability to produce propane air in excess of storage quantities depends on the availability of feedstock on the spot market. The ability to divert interruptible sendout to firm customers depends on weather patterns and timely dispatch decisions.

However, as Tables 8 and 9 indicate, the Company has sufficient operational flexibility and supply diversity to meet sendout requirements in the event of design conditions. In the 1984/85 heating season, the Company can meet over 70 percent of design requirements in excess of normal with LNG, firm Algonquin underground storage and propane. In the 1985/86 heating, the year before Canadian pipeline supplies are expected, these firm sources are sufficient to meet only 40 percent of design requirements in excess of normal. In 1985/86, the Company must rely more heavily on receiving pipeline gas in excess of normal quantities and timely dispatching decisions. In the 1986/87 and 1987/88 heating seasons, Canadian supplies are forecast to be available, reducing the Company's reliance on storage in a normal year. In these years, LNG and underground storage, and propane are available to meet approximately 70 percent of design requirements in excess of normal.

The Council concludes on the basis of the data in Tables 8 and 9 that Commonwealth has adequate resources to meet the design requirements of its customers.

Table 8
Commonwealth Gas Company
Comparison of Resources and Requirements
Design Year - Non-Heating Season
(MMcf)

Additional Requirements	1984	1985	1986	1987
Design Firm Sendout	11917	12210	12301	12493
Normal Firm Sendout	(10720)	(10962)	(11027)	(11189)
Excess	1197	1248	1274	1304
Maximum Storage Refill	1868	1919	1363	1962
Total Excess Requirements	3065	3167	2637	3266
Additional Resources				
AGT F-1	1846	1795	1603	1428
Trans-Niagara	0	0	0	957
TGT CD-6	700	98	128	284
Diverted Interruptible	4631	4622	4104	5252
Total Resources	7177	6515	5835	7921

Source: Forecast, Tables G-5, G-22A,B.

Table 9
Commonwealth Gas Company
Comparison of Resources and Requirements
Design Year - Heating Season
(MMcf)

Additional Requirements	1984-85	1985-86	1986-87	1987-88
Design Firm Sendout	25617	26119	26350	27207
Normal Firm Sendout	(23680)	(24133)	(24343)	(25171)
Excess	1937	1986	2007	2036
Additional Fuel Gas Reimbursement	61	96	80	69
Total Excess Requirements	1998	2082	2087	2105
Additional Resources				
AGT F-1	408	463	914	1237
WS-1	56	112	327	316
ST-1	38	43	112	233
Trans-Niagara Storage	0	0	0	166
TGT CD-6	862	801	782	750
Storage	530	567	553	522
LNG Storage	1351	753	1297	1038
LP-Air	45	45	31	31
Diverted Interruptible	431	441	541	611
Total Additional Resources	3721	3225	4557	4904

Source: Forecast, Tables G-4A, G-5, G-22A,B.

C. Peak Day

In addition to having sufficient gas supplies to meet the seasonal and annual requirements of its customers, a Company must have sufficient daily pipeline supplies and facility capacities to meet the peak day requirements of its customers. A Company must be able to meet the requirements of its entire service territory, as well as the requirements of each of its divisions. Table 10 outlines Commonwealth's system-wide peak day resources and projected requirements for the 1985 through 1988 period.

As discussed previously, CONTEAL volumes will be available on a firm basis in November 1985, increasing the Company's peak day resources by approximately 12 MMcf in 1985/86 and 13.5 MMcf in 1986/87. The Company expects pipeline gas from the Trans-Niagara project to be available for the 1986/87 peak day. The storage component is expected to be available in the following year. Should the Trans-Niagara Project be delayed in regulatory proceeding such that the volumes are not available within the forecast period, the Company would have sufficient resources to meet its forecasted peak day requirements on a system wide basis. The Company also indicates that it plans to retire the Cambridge propane-air plant in 1986, reducing its daily sendout capacity by 3.6 MMcf.

Also noteworthy is the Company's daily entitlement from Boston Gas. Typically, a company does not consider those sources dependent upon best-efforts transportation arrangements as firm supplies available during the coldest days of winter. However, Commonwealth has indicated in its forecast that it relies to some degree upon best-efforts redelivery of Boston Gas storage to meet peak day requirements in the Cambridge division.

TABLE 10
COMMONWEALTH GAS COMPANY
SYSTEM PEAK DAY RESOURCES AND REQUIREMENTS
(MMCF)

		1983/84	1984/85	1985/86	1986/87	1987/88
Pipeline						
AGT	F-1	71.0	71.0	71.0	71.0	71.0
	ST-1	6.2	6.2	6.2	6.2	6.2
	WS-1	35.6	35.6	35.6	35.6	35.6
	SNG-1	21.9	21.9	21.9	21.9	21.9
TGT	CD-6	55.4	55.4	55.4	55.4	55.4
Supplemental						
	Propane	18.0	18.0	18.0	14.4	14.4
	LNG	130.0	130.0	130.0	130.0	130.0
	Boston Gas Storage	8.0	8.0	8.0	8.0	8.0
Future Supply Sources						
CONTEAL	F-2			6.9	10.4	10.4
	F-3			5.1	3.1	3.1
	Trans-Niagara				10.7	10.7
	Trans-Niagara Storage					13.1
TOTAL RESOURCES		346.1	346.1	358.1	366.7	379.8
FORECASTED REQUIREMENTS		305.3	315.3	322.1	325.4	334.5

SOURCE: Tables G-23; Response to Information Request S2-1 dated July 2, 1984.

Commonwealth has submitted evidence on the reliability of this source of supply during the heating season. The record indicates that during the 1981/82 and 1982/83 heating seasons the Company requested redelivery of gas stored for its account by Boston on an average of 12 days in each heating season, on an average day of 45 degree days. On all of those days except one, the Company received volumes in excess of requested levels. On the remaining day, a day 19 percent warmer than a peak day, but two days following division and system peak, the Company received less than half of the requested amount. On the peak day in each of those seasons (68 degree days and 60 degree days), the Company received 7.9 and 6.6 MMcf, respectively, amounts in excess of requested volumes.

The Company states that it would expect not to receive requested storage volumes from Boston Gas only in the event that Boston Gas experienced unexpected technical problems preventing delivery. In fact, Boston Gas' capacity in the Boston Division exceeded its 1983 peak day requirements by 35 percent. If interconnections and back-up capacity are included, this margin increases to 85 percent.[41] It does not appear that Boston Gas lacks the excess capacity to serve Commonwealth when necessary. Nevertheless, the Council requests Commonwealth, in its next filing, to state in detail its expectations regarding the future availability and reliability of this peak shaving supply. Condition 4 addresses this issue.

To more accurately evaluate the Company's ability to meet the peak day requirements of its customers, it is necessary to evaluate daily pipeline entitlements, sendout facility capacities, and peak day

41. Boston Gas Co., 10 DOMSC 278 at 333 (1984).

requirements in each of its divisions. Table 11 summarizes the Company's plans to meet the peak day requirements of each of its divisions throughout the forecast period. The forecast data has been amended to reflect the recent approval by FERC of the CONTEAL project. Table 12 outlines information on the maximum daily entitlements in each division, and for the system, for each pipeline supply source.

As indicated, the Worcester division is served only by Tennessee. However, the Company has flexibility in the location of receipt of its system MDQ within that division, because the sum of the maximum takes at the four individual take stations exceeds the system MDQ of 55.4 MMcf by 43.6 MMcf. Supplemental supply is available to Worcester in the form of propane and LNG storage. The Worcester area has sufficient existing resources to meet forecasted peak requirements through the forecast period. No additional resources are targeted for this division within the forecast period.

The Algonquin pipeline serves the Company's Framingham, Cambridge and New Bedford divisions, allowing the Company certain operational flexibilities. The F-1 and WS-1 contracts provide that the sum of the individual take station's MDQs are greater than the system MDQ.

The planned allocation to Framingham of the Algonquin system MDQs are within that division's daily entitlement. LNG vaporization capacity from the Hopkinton facility is also available to the division. The resources currently available to the Framingham division are sufficient to meet forecasted requirements through 1987/88. Nevertheless, the total daily entitlement from the CONTEAL project is currently designated to be received at the Westwood take station. Additionally, a portion of the Trans-Niagara storage volumes are designated to be delivered to Framingham.

TABLE 11

COMMONWEALTH GAS COMPANY
PEAK DAY RESOURCES AND REQUIREMENTS BY DIVISION
(MMcf)

WORCESTER	1984/85	1985/86	1986/87	1987/88
TGT CD-6	55.4	55.4	55.4	55.4
Propane Storage	14.4	14.4	14.4	14.4
LNG Storage	60.0	60.0	60.0	60.0
Total Resources	129.8	129.8	129.8	129.8
Requirements	114.5	118.0	119.3	122.9
FRAMINGHAM				
AGT F-1	25.3	25.3	25.3	25.3
WS-1	2.8	2.8	2.8	2.8
SNG-1	13.2	13.2	13.2	13.2
LNG Storage	40.0	40.0	40.0	40.0
CONTEAL F-2		6.9	10.4	10.4
F-3		5.1	3.1	3.1
Trans-Niagara STC				8.6
Total Resources	ERR	93.3	94.8	103.4
Requirements	76.7	78.1	78.7	80.7
CAMBRIDGE				
AGT F-1	25.8	25.8	25.8	25.8
WS-1	23.0	23.0	23.0	23.0
ST-1	6.2	6.2	6.2	6.2
Propane Storage	3.6	3.6	0.0	0.0
Boston Gas Storage	8.0	8.0	8.0	8.0
Trans Niagara C-1			10.7	10.7
Trans-Niagara STC				1.5
Total Resources	66.6	66.6	73.7	75.2
Requirements	63.8	65.1	65.1	67.2
NEW BEDFORD				
AGT F-1	19.8	19.8	19.8	19.8
WS-1	9.8	9.8	9.8	9.8
SNG-1	8.7	8.7	8.7	8.7
LNG Storage	30.0	30.0	30.0	30.0
Trans-Niagara STC				3.0
Total Resources	68.3	68.3	68.3	71.3
Requirements	61.2	61.8	62.5	63.8

Source: Tables 6-23.

TABLE 12

COMMONWEALTH GAS COMPANY
CITYGATE STATION CAPACITIES BY DIVISION
(MMcf)

Source	Worcester	Framingham	Cambridge	New Bedford	Sum of the Citygate MDQ's	System MDQ
	Division					
TGT CD-6	99.0				99.0	55.4
AGT F-1	-	30.8	25.8	22.8	79.4	71.0
WS-1	-	16.3	9.8	9.8	35.9	35.6
SNG	-	13.2	-	8.7	21.9	21.9
ST-1	-	-	6.2	-	6.2	6.2
AGT F-2,F-3	-	13.5	-	-	13.5	13.5
AGT C-1,STC	-	8.6	12.2	3.0	23.8	23.8
Total	-	60.3	41.8	41.3	143.4	134.7

Source: Exhibit D-2, EFSC Docket No. 82-5.

That portion of the Algonquin' system MDQ allocated to New Bedford is within that division's MDQ. LNG is available as a supplemental supply. Resources currently available to the division are sufficient to meet forecasted peak day requirement through 1987/88. The Company currently plans to allocate a portion of the Trans-Niagara storage volume to the New Bedford division.

The Cambridge division is served only by the Algonquin pipeline. Additionally, the division has propane capacity and the Boston Gas storage volumes, discussed previously at 41. As the Company plans to allocate its existing system-wide resources on the Algonquin pipeline, the Cambridge division has sufficient existing resources through 1986/87. The Company plans to take gas from its F-1 contract in Cambridge up to that division's MDQ. The entire ST-1 daily entitlement is taken in Cambridge. Additionally, the Company plans to allocate gas from its WS-1 contract in excess of the maximum allowable take in Cambridge. As a comparison of Tables 11 and 12 indicates, the Company plans on receiving 23.0 MMcf of the WS-1 contract in Cambridge, although Algonquin's contractual maximum daily delivery obligation is only 9.8 MMcf.

In the last decision,[42] the Council examined the Company's ability to move gas between separate service territories using the facilities of an interstate pipeline. The Council's concern at that time was the ability to move gas from what was then called Zone II (equivalent to New Bedford) to Zone I (the equivalent of Worcester, Framingham and Cambridge combined). The Council found in that decision that Zone I, as

42. 9 DOMSC 396-399, (1983).

a whole, did not have sufficient resources to meet forecastd requirements.[43]

The Company stated in that docket that because both zones are served by Algonquin, the Company is able to share gas between service territories under certain conditions. The Company stated that it is possible to back off pipeline quantities in Zone 1 while increasing the take in Zone 2, provided it causes no problems for Algonquin or any of Algonquin's customers,. Addtionally, the Company stated that it is possible to increase the pipeline take in Cambridge provided it is reduced in the western part of Zone I (Framingham). Upon further questioning on the reliability of this displacement arrangement, the Company stated that the peak day requirements of both zones could be met without the displacement arrangement.

Commonwealth has adjusted its sales forecast in this year's filing to reflect the changes in the Trans-Niagara project. Upon examination of this year's forecast, it is apparent that sufficient daily resources are available on a firm basis to Zone I. However, the Council is concerned about the Company's ability to share gas <u>within</u> the so-called Zone I, or more specifically, between the Framingham area and the Cambridge area. The concern results from the Company's disaggregation of its sendout and peak day forecast from a two-zone to the present four division basis. The record indicates that the Company's ability to

43. This apparent shortage resulted from the fact that immediately prior to the issuance of the Council's decision, the Canadian National Energy Board released its decision on that Country's natural gas surplus, which reduced by half all pending export applications, including the Pan-Alberta/Algonquin contract. Without further information, the Council adjusted the Company's forecast of supply available from the Canadian Project.

meet peak day requirements in Cambridge is dependent upon the ability to displace gas from the more secure Framingham area to the Cambridge area using the facilities of the Algonquin Gas Transmission Company.

As previously stated, the Company can share gas between the divisions served by Algonquin on a firm basis given the fact that the sum of the allowed takes at the individual citygate stations exceeds the system MDQ for the F-1 and WS-1 contracts. However, any delivery to Cambridge in excess of that division's MDQ on the Algonquin pipeline would require the displacement arrangement.

The Company would need the displacement arrangement only on days when its peak sendout requirements exceeded its firm daily sendout capacity in Cambridge, a volume of 53.4 MMcf. According to staff calculations, in the 1984/85 heating season, this would occur only when the degree day level exceeded 63 degree days on a 65° base, or when the temperature is less than 2° Fahrenheit.[44] For 1985/86 and 1986/87, these figures decrease to 62 and 61 degree days, respectively. In 1981/82, a heating season 3 percent colder than normal, the temperature fell below 2° on only two days.

The Council is aware that Commonwealth has used this displacement arrangement to meet peak day requirements in Cambridge in the past two years. On the 1982/83 peak day, Algonquin delivered 14.2 MMcf of WS-1 volumes to Cambridge, a volume which exceeded Cambridge's WS-1 entitlement by 4.4 MMcf. The Cambridge division received its full F-1

44. This figure is based on an analysis of the average daily base load and average heating increment for the heating season as a whole.

and ST-1 entitlements on that same day. Additionally, Algonquin delivered to New Bedford 13.3 MMcf of WS-1 on that same day, a volume which exceeded that division's WS-1 daily entitlement by 3.5 MMcf. The Council is also aware that the displacement arrangement which serves to provide Cambridge with gas in excess of its division MDQ on the Algonquin pipeline has been in place for some time.[45]

Therefore, it is apparent that the physical capacity exists to serve the Cambridge division in excess of its MDQ.[46] However, it is not clear that the capability exists to serve Cambridge up to the levels expected on a peak day.[47] Also, the Council does not have enough information to evaluate the reliability of this displacement arrangement.

Therefore, the Company is ordered to provide in its next filing an in depth discussion of the means which are currently in place to transfer gas to the Cambridge area from the Framingham area in excess of the Cambridge division's MDQ. This discussion should include, at a minimum, a discussion of the operational procedure which the Company must follow when it is necessary to shift gas to Cambridge from

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45. Billing data examined by Staff indicate that during the 1980/81 heating season the combined take at the two Cambridge citygate stations exceeded 41.8 MMcf, the division's current Algonquin MDQ. This was true before transportation of the Algonquin storage volumes were firmed up. Additionally, data for the 1982/83 heating season indicates the Company received in Cambridge volumes exceeding its entitlement on the Algonquin pipeline on numerous occasions. These excess volumes ranged from 3.1 MMcf to 9.2 MMcf. See Docket No. 82-5, Response to Information Requests D1(h), dated November 23, 1982.
46. The Company states that the maximum daily capacity based on physical capabilities at the Third Street and Brookford take stations are 57 MMcf and 51 MMcf, respectively. Exhibit S14, Docket No. 83-5.
47. For the 1985/86 peak day, the Company would need a minimum of 53.5 MMcf of Algonquin gas, if requirements develop as projected and propane and Boston Gas Storage are available. A delivery of this volume would exceed the Cambridge division's MDQ on the Algonquin pipeline by 11.7 MMcf.

Framingham in excess of Cambridge's MDQ; the maximum combined physical capacity at the two Cambridge take stations; the historical maximum take on a single day in Cambridge; the historical reliability of the displacement arrangement; and the impact that future projects are expected to have on the need for, and the availability and reliability of the displacement arrangement. Condition 5 addresses this issue.

D. Cold Snap

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

The Company is in an enviable position with regard to its ability to meet sustained periods of extreme sendout. It is unique in that the Hopkinton and Acushnet LNG facilities provide it with one of the largest storage to sendout ratios in the State. At peak weather conditions, or 70 degree day days, the Company can meet sendout requirements for over a month, if storage inventories are at 100 percent of capacity. To meet two consecutive weeks of peak sendout, the Company needs to have its storage inventory at only 45 percent of capacity. These figures vary by division, given their different sendout and supply characteristics. The Cambridge division can meet peak day sendout requirements for only 10 days, due to its limited peak shaving capacity and storage.[48]

48. This figure assumes that the additional pipeline quantities displaced by Algonquin to Cambridge, as discussed <u>supra</u> at 59, would be available for each day during a cold snap. Whether this assumption is reasonable is unclear and it is one of the issues the Company should address in its response to Condition 5.

It is not probable that an extended period of weather and sendout at peak levels would occur. More likely, a cold snap would consist of a series of days on which the degree day level averaged somewhat less than that of peak.[49] During a two-week period of 60 degree days, the Company, on a system-wide basis, can meet 47 consecutive days of sendout if storage is full. To meet a two-week period of 60 degree day days, the Company would need to have storage inventories of approximately 30 percent of capacity. Again, these figures vary by division. Cambridge requires no peak shaving capacity at the 60 degree day level, assuming the projected quantities of pipeline gas in excess of the division's MDQ are available. If these quantities are not available, the Company would need to send out slightly less than 11 MMcf of propane and Boston Gas storage per day. Current storage capacity would allow the Company to meet these conditions for nearly 7 days, if propane storage is replenished after the fourth day. The ability to replenish propane storage depends on its availability on the spot market.

The Council finds that the Company is able to meet the requirements of its customers during a cold snap, assuming it maintains its LNG and propane inventories at reasonable levels.

V. Hopkinton LNG Corporation

Hopkinton LNG Corporation is jointly owned by the Commonwealth Energy System and Air Products and Chemicals, Inc., a corporation otherwise unrelated to Commonwealth Energy System or any of its subsidiaries.

49. During January 1981, a month which was 16 percent colder than a normal January, the Company experienced a two-week period of days which averaged 53 degree days. See Exhibit SF-9, Docket No. 83-5 and Exhibit SF-8, Docket No. 82-5.

Hopkinton owns an LNG storage facility consisting of five above-ground consolidated storage tanks and associated liquefaction and vaporization equipment located in Hopkinton and Acushnet, Massachusetts. Hopkinton provides liquefaction, storage and vaporization services pursuant to a 25 year contract with Commonwealth, which expires January 1997. Hopkinton neither owns nor sells any gas of its own. Hopkinton does not intend to construct new facilities during the forecast period.

Given the above facts the Council APPROVES unconditionally the Hopkinton LNG Corporation's First Annual Supplement to its Second Long-Range Forecast.

VI. Order

The Siting Council APPROVES the First Annual Supplements to the Second Long-Range Forecast of Commonwealth Gas Company and Hopkinton LNG Corp. subject to the comments in this Decision and to the CONDITIONS set forth below. It is hereby ORDERED:

1. That Commonwealth provide in its Third Supplement its findings on base use factors, along with all supporting documentation, as far as is practicable.

2. That Commonwealth provide in its Third Supplement documentation in support of its added load projections by division and class of service for each year of the forecast period. The Company should address all those issues discussed herein.

3. That Commonwealth provide in its Third Supplement a detailed discussion of the status of its conservation monitoring program, including computerization of data, the impact of conservation (as opposed to economic factors) on sales, and

conservation patterns during the year and on peak days. The Company shall also discuss the status of its marketing information and statistical reporting systems and future plans for integrating these systems into its forecast of sendout requirements.

4. That Commonwealth state in its Third Supplement its expectations regarding the future availability and reliability of the Boston Gas Storage arrangement.

5. That Commonwealth discuss in its Third Supplement the means which are currently in place to transfer volumes of gas to Cambridge from Framingham in excess of the Cambridge division's MDQ on the Algonquin system. The Company should address all those issues outlined herein.

6. That Commonwealth and Hopkinton shall file their Second Annual Supplements to the Second Long-Range Forecast on December 3, 1984. This filing will be for informational puposes only and will not be adjudicated. The Third Annual Supplements shall be due on September 2, 1985, and shall encompass the above Conditions.

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

Unanimously APPROVED by the Energy Facilities Siting Council on October 24, 1984 by those members and designees present and voting: Sharon M. Pollard, (Chairperson); Joellen D'Esti (for Secretary Evelyn F. Murphy); Sarah Wald (for Secretary Paula W. Gold); Stephen Roop (for Secretary James S. Hoyte); Robert W. Gillette (Public Environmental Member); Joseph W. Joyce (Public Labor Member). Ineligible to vote: Edward H. Collagan, Jr. (Public Oil Member).

30 October 1984
Date

Sharon M. Pollard
Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Massachusetts Municipal Wholesale Electric Company (MMWEC) for Approval of its 1982 Long-Range Forecast of Electric Needs and Requirements	EFSC 82-1

Final Decision

Lawrence W. Plitch, Esq.
Hearing Officer

On the Settlement

James M. Coyne
Lead Electric Analyst

William S. Febiger
Staff Analyst

TABLE OF CONTENTS

I. BACKGROUND AND PROCEDURAL HISTORY

A. A Description of MMWEC

The Massachusetts Municipal Wholesale Electric Company ("MMWEC" or "the Company") serves 34 municipally owned electric systems in Massachusetts.* MMWEC performs such centralized planning functions as demand forecasting, supply planning, and the issuance of tax-exempt financing for its members.

MMWEC is a public corporation of the Commonwealth formed in 1975. Under Chapter 775 of the Acts of 1975 MMWEC was allowed to issue tax-exempt bonds for the purpose of financing electric power facilities, to operate without taxes on income, and to participate in a broad range of electric supply planning functions, including membership in NEPOOL. A nine-member board, of which two are gubernatorial appointees and seven are elected by the member towns governs MMWEC.

Each MMWEC member operates a local distribution system. Ultimate decisions regarding participation in jointly-owned generation facilities and other supply agreements are made at the local level, with the assistance of MMWEC's planning staff. In 1981, 33 members sold 3.6 billion kilowatthours (including sales in 6 nonmember communities) with an annual peak demand of 747 megawatts. This represents approximately 10% of total Massachusetts electricity sales, making MMWEC the third largest electric company in the state.

B. Procedural History

The last filing reviewed by the Council was MMWEC's 1979 Forecast in EFSC Docket No. 79-1. The lengthy proceedings in 79-1, which involved four intervenors, culminated with a January, 1981 decision. MMWEC's

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* Concord recently joined MMWEC but is not included in this forecast.

demand forecasting methodology and the proposed acquisition of an additional 138 MW in the Seabrook units drew considerable attention in these proceedings. The Council, in rendering its decision, approved both the supply and demand components of the filing, with the demand forecast being subject to nine conditions. Since that time, Council staff and the Company's staff have held two meetings to discuss progress in the MMWEC demand forecasting methodology.

The date originally established for MMWEC's current filing was set at December 1, 1981 in Condition 9 of the 79-1 Decision. This date was subsequently moved to May 15, 1982 per agreement by Council and MMWEC staff.

A Notice of Adjudicatory Proceedings was issued on August 2, 1982 and a pre-hearing conference was held on September 8, 1982. Mass PIRG, the only party to file a motion to participate in the proceedings, subsequently withdrew its motion on September 21, 1982. The proceedings have resumed without intervention or the active participation of interested parties.

EFSC staff's First Set of information requests were sent to MMWEC pursuant to a Procedural Order on September 28, 1982. These requests were revised following a technical session between MMWEC and Council staff and a revised version was sent under a second Procedural Order on October 8th. Responses to this First Set of information requests were received on October 27th, with the exception of a few requests that required additional time.

Following several discussions regarding a mutually acceptable format for the further adjudication of this case, a second Pre-Hearing Conference was convened on March 4, 1983.

The EFSC Hearing Officer and the Attorney for MMWEC agreed to a set of procedures that included a series of informal technical sessions between Company and Council staffs, subsequent written information requests, if necessary, and an ultimate decision pursuant to the guidelines in EFSC's "Settlement" provision. Rule 16.2. This procedure ensured the rights of both the EFSC and the Company to request, if necessary, formal hearings prior to the presentation of a Settlement Decision to the Council.

Pursuant to this agreement, Council and Company staff held three separate technical sessions to discuss demand, supply, conservation and load management issues. Council staff also issued its Second, Third, Supplemental Third, and Fourth set of Information Requests on March 9, May 5, May 25, and July 1, 1983, respectively to complete the discovery process. This process resulted in a thorough exploration of the issues.

After several months of meetings and discussions designed to reach a settlement agreement on a tentative decision, the Council staff terminated the settlement process. MMWEC was so notified on December 2, 1983 and a subsequent procedural order dated December 18, 1983 outlined a scope for hearings to be conducted on the economics of Seabrook II. A prehearing conference was conducted on February 15, 1984 at which MMWEC requested a delay in filing its direct case until after new cost estimates for Seabrook were published. Other motions contesting the Council's jurisdiction and the right of intervening parties to be heard were submitted by MMWEC. On March 1, 1984 new cost projections were issued by PSNH and MMWEC cast its vote to cancel Seabrook II at a meeting of the joint owners on March 30, 1983. On April 12, 1984, attorneys for MMWEC sent a letter to the Hearings Officer requesting that the hearings on Seabrook II be cancelled since "no issue in controversy exists" in this portion of the case. (See Appendix A) On May 11, 1984, the Hearing Officer issued a procedural order that terminated the hearings on Seabrook II.

With uncertainty surrounding both Seabrook units and changing costs and availability factors for other large scale supply sources, and due to the already extensive time period that this case has consumed, it was determined by the Council to issue a decision on the demand forecast and on only those portions of the supply forecast involving conservation and small scale load additions. A comprehensive supply plan analysis, including Seabrook and other large scale supply options will be issued in response to the next MMWEC forecast Supplement, due on Nov. 1, 1984.

II. COMPLIANCE WITH THE CONDITIONS IN 79-1

The previous EFSC Decision in Docket 79-1 contained ten conditions.

Condition 1 directed MMWEC to address inconsistencies in data collection and customer classification. In response, the residential Appliance Saturation Rate Survey conducted in 1980 has enabled MMWEC to reliably disaggregate hot water and electric space heating customers for the first time. Additionally, the survey provided important base year appliance saturation, dwelling-type mix data, and demographic information on residential customers. The survey, if conducted on a regular basis, should prove to be a reliable solution to the forecasting staff's past problems with a multitude of rate classes existing across municipals that do not consistently separate residential customers by major end-use. The Council commends MMWEC for implementing this survey. It has provided an enriched data base for residential demand forecasting, and we strongly urge the Company to develop a plan for its continued implementation over time.

The disaggregation of seasonal residential customers has been accomplished in the towns where separate rates exist, and are forecast separately in the "Other" class.

The reliable disaggregation of commercial and industrial customers by 2-digit SIC codes remains to be achieved. Each Municipal essentially has "large" and "small" use rate classes that do not discriminate by customer type. The Company, in response, initiated a commercial/-industrial survey in 1981 and was able to partially utilize its results in the instant Forecast. The fundamental problem, however, extending from the inability to discern, e.g., an office building from a textile mill for purposes of forecasting, remains unresolved in this Forecast.

The Council recognizes the commercial/industrial dichotomy as a problem without an easy solution and one that commonly plagues forecasting efforts in these areas. The Company has stated that the commercial/industrial survey data "can facilitate disaggregaton of the Commercial and Industrial rate classes".[1] We commend the Company for implementing its Commercial/Industrial survey, and look forward to seeing increasingly reliable forecasts as a result. The Council encourages the utilization of surveys in conjunction with an overall rigorous forecasting framework. This is in contrast to forecasts based almost exclusively on surveys and/or interviews for which MMWEC has been criticized in the past.

The MMWEC survey offers one method of improving the commercial/industrial data base. Another possibility that warrants MMWEC's serious consideration is to work towards enhancing billing systems at the municipal level that can offer more detailed information for classification and forecasting purposes. EFSC Rule 63.7 requires a

1 Forecast, Introductory Section, Response to Condition 1.

separate forecast for the commercial customer class and disaggregation of the industrial forecast at the 2-digit SIC code level. At present, all of state's six large electric companies comply with the industrial requirement of 63.7 with the exception of MWMEC. NEES, BECo, Comm Electric and EUA forecast industrial sales using a "bottom-up" method by SIC. NU forecasts industrial sales in aggregate by operating company and then distributes the aggregate forecast across 2-digit SIC's in a "top-down" approach.

The Council recognizes that a "bottom-up" approach is ordinarily a superior forecasting methodology because the best set of explanatory variables can be developed for each SIC. But, when insufficient data or other special circumstances make such an approach impractical for purposes of obtaining the most reliable aggregate industrial forecast, a "top-down" method of first forecasting industrial sales in aggregate and then distributing sales down to the SIC level still holds advantage over no disaggregation at all. In particular, such a disaggregation in conjunction with available load data by SIC would allow MMWEC to evaluate rate structure, conservation, load management, and co-generation options tailored for the varying power needs of the members' industrial customers.

In light of the aforementioned benefits of a disaggregated forecast, and Rule 63.7, the Council expects MMWEC to start building a data base that reliably distinguishes between commercial and industrial customers, and provides either for classifying industrial sales by 2 digit SIC codes or an equivalent goal. The Council does not expect this effort, however, to provide a "bottom-up" industrial forecast (by 2 digit SIC) until sufficient data has been collected, presumably over several years. The Council is most concerned that MMWEC show progress in attaining this longer term goal, while taking advantage of intermediary results as is practical. To this end, we require MMWEC to report to the Council on commercial/industrial data base development with its next forecast in Demand Condition No. 1.

Condition 2 directed MMWEC to reevaluate its survey-interview approach to forecasting the number of residential customers and industrial sales, and outlined specific standards for conducting interviews for gathering forecast data.

MMWEC, in response to this and other directives has presented entirely new methodologies for its residential and industrial forecasts. These methodologies do not incorporate interviews as an integral part of the forecast and therefore satisfy the second condition.

Condition 3 directed MMWEC to reevaluate its industrial methodology and to continue development of a quantitative approach to forecasting industrial electricity sales. In response, MMWEC has developed an econometric model which fully satisfies this directive. The new industrial methodology is critiqued in a subsequent section of this Decision.

Condition 4 directed MMWEC to reevaluate its commercial forecast methodology. The 1979 commercial forecast essentially assumed a stable ratio of commercial to residential sales. In response, MMWEC has developed an econometric methodology that fully satisfies this Condition. The new methodology is critiqued in the commercial demand section of this Decision.

Condition 5 directed MMWEC to continue with its plans to evaluate and use the newly implemented residential Appliance Saturation Survey, Residential Conservation Service (RCS) program data, and the new Census data. In the present forecast, the Company has taken considerable advantage of its survey and the 1980 Census data. MMWEC has not, however, been able to gain full access to the RCS data due to confidentiality constraints. The Council will assist MMWEC in its attempts to access the data and expects MMWEC to evaluate the use of the available data for the next filing. The data may prove particularly valuable for assessing the thermal performance characteristics of the housing stock within each member's system and to assess the commensurate conservation potential.

Additionally, the data may serve as a limited cross check of the saturation survey and aid in demand forecasting.

Condition 6 directed MMWEC to evaluate the collection and use of data beyond that which the Company has traditionally used for demand forecasting. Data such as sales-mix, geographic location, weather, income, and industry mix were cited. MMWEC was also directed to prepare a methodology development plan that considered such data for its members and to submit this analysis to the Council.

MMWEC met with Council staff on two occasions, August 24, 1981 and December 8, 1981, in response to Condition 8. Issues explored at these meetings included load forecasting methodologies, data inputs to the models, the Commercial/Industrial survey, and the Load Management Study required in Condition 7. These presentations combined with MMWEC's expanded use of available data have fully satisfied the intent of Condition 6.

Condition 7 was a load management directive, and is covered in the conservation and load management section of this Decision.

Condition 8 required MMWEC to report to the Council on its progress in implementing the first seven Conditions at meetings of approximately three month intervals. MMWEC has fully complied with the intent of this Condition with the August and December, 1981 meetings previously noted.

Condition 9 established MMWEC's next filing date at December 1, 1981, which date was subsequently moved to May 15, 1982. On this date, the Company timely filed its 1982 Forecast.

Condition 10 was a load management related directive and is discussed along with Condition 7 in that section of this Decision.

III. ANALYSIS OF THE DEMAND FORECAST

A. A Comparison of Previous and Current Forecasts

The forecasts presented to the Council by MMWEC have marked the evolution of a demand forecasting methodology from a simplistic aggregation of individual municipal forecasts, largely based on judgement, to a combination of more sophisticated econometric and end-use models.

The 1976 demand forecast filed by MMWEC relied heavily on the collective judgements of the municipal managers and historical trending. This methodology was found to be suitable for the municipals at that time.

The Company employed the same methodology in its 1977 supplement which was again deemed satisfactory, with the exception of a requirement to break down the industrial forecast by 2 digit SIC code in future filings.

In the Council's review of the 1978 supplement, serious questions were raised regarding the continued reliance by MMWEC on a largely subjective forecasting methodology. The Council stated, in its October 1978 decision, that "while it has been adequate during the Company's start up phase, the methodology will not be able to provide reasonably accurate and statistically justified projections of demand and consumption in subsequent forecast periods." The Council also found, as noted *supra.*, that "the forecast is not adequate or sufficient to justify any generating capacity beyond that which has been approved in earlier decisions of the Council." Attached to the decision were numerous demand conditions resulting from a stipulation agreement between MMWEC and the Council Staff.

MMWEC's third supplement, presented to the Council in 1979, incorporated a new demand methodology. While the EFSC recognized improvements in the Company's methodology, the Council was critical of MMWEC's over-reliance on the survey-interview technique. In the Decision, the Council found "this technique too subjective, too judgemental, and too burdensome to review to be considered a reasonable statistical projection method". *See* EFSC No. 79-1. The ten demand related conditions attached to this decision are discussed in detail, *infra*.

Early forecasts predicted system noncoincident annual peak growth rates greater than 5%, which have now declined to a projected 2.5%. In comparison, the 1983 NEPOOL forecast predicts regional winter peaks to grow at an annual rate of 1.9%. From 1976 through 1981, the New England Peak grew 1.2% per year while the MMWEC members peak grew 2.2% per year.

MMWEC's 1982 demand forecasts for the 33 members municipals are summarized in Table 1 in terms of average growth rates.

As will be evident throughout the Council's demand side analysis, we are encouraged by MMWEC's significant strides in demand forecasting since our last review. The Company, in the present Forecast, has shown evidence of a commitment to the development of a *reviewable*, *appro-*

Table 1

Energy and Peak Forecasts for MMWEC Members, 1981-1991*

MMWEC TOWN	(COMPOUND ANNUAL GROWTH RATES)
Ashburnham	2.0%
Belmont	0.7
Boylston	1.9
Braintree	2.8
Chicopee	1.7
Danvers	2.5
Georgetown	1.5
Groton	1.6
Hingham	2.2
Holden	1.8
Hudson	5.6
Hull	.3
Ipswich	1.2
Littleton	9.7
Mansfield	2.3
Marblehead	0.8
Merrimac	0.8
Middleboro	2.3
Middleton	2.9
N. Attleboro	1.7
Paxton	1.5
Peabody	1.7
Princeton	1.9
Reading	2.5
Rowley	2.1
Shrewsbury	3.1
S. Hadley	2.1
Sterling	2.8
Templeton	5.6
Wakefield	1.7
W. Boylston	1.5
Westfield	2.2
MMWEC TOTAL	2.4

* Calculated from the forecasts in Forecast Table III-1.

priate, and reliable forecast methodology. The Company's newly developed methodologies are both reviewable and appropriate. Our major concerns at this time are directed at improving reliability. This represents a tremendous improvement over past forecasts. The nature of our critical review is not intended to take away from these accomplishments, but to guide the Company in its ongoing methodological development.

B. The Residential Forecast Methodology

MMWEC's new residential forecasting methodology is derived from the NEPOOL/Battelle Model. The Council is pleased that the Company has adopted a detailed end-use methodology for residential forecasting. We have recently rendered a thorough critique of the NEPOOL Residential Model as applied to Commonwealth Electric's Service area, and to the extent MMWEC's use of the model is similar, we draw on that analysis here. COM/Electric, (No. 82-4, 9 DOMSC 292-330, 1983).

The model consists of three major components: number of customers; number of appliances; and average annual use per appliance. The projected customer count times the number of appliances per customer times the average use per appliance yields the aggregate residential electricity forecast.

This "bottom-up" end-use approach to residential forecasting is now being utilized by every major electric company in the Commonwealth. The Council finds the overall methodology to be acceptable for MMWEC. As with the other companies employing an off-the-shelf version of the NEPOOL model, we look to the quality of the data used to run the model in assessing its reliability for MMWEC.

Specifically, we have analyzed each component of the model and the methods used to project those components in terms of their demonstrated applicability for the MMWEC members. At this point, we find that MMWEC has made a credible first-cut at adapting the NEPOOL Residential Model to its diverse "service area". We do, however, see room for improvement and make several suggestions towards this end. The Council's concerns predominantly lie with MMWEC's use of data and model parameters that are not demonstrably reflective of its members' residential customers. Also, while the Council recognizes the practicality of grouping towns for forecasting purposes, we see the potential for forecast bias arising from MMWEC's present grouping.

The Council's specific concerns are delineated in the following analysis of the model's major components.

1. Customer Projections

The number of residential customers in each town is forecast based on town-specific population projections made by various Regional Planning Commissions and Councils (in 1975) and the U.S. Census Bureau's projections of average household size. The population projection divided by the persons per household projection is taken to be the residential customer forecast for each member town.

MMWEC has adjusted the Regional Planning Commission (R.P.C.) population forecasts to reflect actual population growth over the 1970-1980 period as compared to the forecast growth rates over the 1975-1980 period. In fact, the RPC forecasts were too high for 28 of the 33 member towns.[2] The adjustment was only made to the 1980-1985 population

2 Exhibit R-3.

projections however. It was assumed that the originally forecast 1985-1995 growth rates would hold true.

The Council has a few concerns with this methodology for population forecasting. Firstly, the RPC projections were three to six years old and may not have accurately reflected current demographic trends. Secondly, to assume that forecast error over the 1975-1980 period should only be recognized in the 1980-1985 projection period ignores what may be a structural weakness in the RPC methodologies that would affect the entire 1980-1995 population forecast. The Census data now available should prove useful in defining and solving the apparent population forecast problems.

The Council recognizes the difficulty associated with obtaining reliable town-specific demographic projections. Given the critical importance of this component to the residential forecast, however, we strongly urge MMWEC to reevaluate this method and explore new methods.

The assumption that average household size in member towns will decline at the same rate as that projected for the U.S. should also be reexamined. From 1970 to 1980, household size in six MMWEC towns declined at a slower pace than the U.S. while the remainder experienced a more rapid decline.[3] The simple unweighted decline from 1970-1980 was 1.2% nationally and 1.4% for MMWEC towns. With some towns the difference was considerable,[4] and MMWEC did adjust the family size trends for five towns. The continued application of a U.S. trend should be made as town specific as possible in light of the historical

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3 Response to Staff Information Request R-4.

4 As an extreme example, Ashburnham's average household size remained constant over 1970-1980, while the U.S. average dropped from 3.19 to 2.82.

evidence, and MMWEC should note all explicit adjustments in its documentation.

2. Appliance Saturation Projections

Base year appliance saturations were measured by MMWEC in its 1980 Residential Appliance Saturation Rate Survey. This survey has given MMWEC a solid foundation from which to forecast trends in appliance ownership. The Company has creatively employed the NEPOOL model in forecasting appliance trends in this Forecast, but we must take note of some methodological problems which should be remedied in subsequent forecasts.

MMWEC has combined towns into four different groups based on their projected electricity price paths over the forecast period. In essence, for the purposes of estimating appliance saturation (and appliance use) trends, MMWEC treats a group of towns as a homogeneous unit. Trends established for the group are then applied to the individual towns' base-year (1980) appliance saturation estimates to produce "town-specific" projections.

The saturation trends developed for seven appliance types are derived from saturation/income functions within the NEPOOL model. These include: electric range, dishwasher, freezer, washer, dryer, room and central air-conditioning.

Trends for seven other appliance types were projected assuming saturation rates in 1980 would hold constant. These include: humidifiers and dehumidifiers, fans, supplementary heaters, well-pumps, lighting, and the miscellaneous category.

The remaining appliance types and splits between appliance types were projected using a series of judgements and/or trends developed by

NEPOOL. These include: electric water heating, fossil heating auxiliaries, refrigerators (frost free and standard), the ratio of frost free verses standard freezers, televisions, microwave ovens, and mobil home appliances.

Electric space heating "penetration" is projected using a comparative cost methodology contained within the NEPOOL model, with adjustments to reflect MMWEC's own electricity price forecasts.[5]

The Council's concerns with these saturation trend methodologies are stated below. Suggestions for addressing problem areas should be viewed as interim measures. We feel that the ultimate solution to reliable appliance saturation forecasting lies in a series of saturation surveys taken over standard time intervals.

° The application of statewide income distribution to MMWEC's members for projecting income-driven saturation levels - MMWEC states that "It was determined that the 1970 and subsequent distributions of households by income class closely approximate those characterizing MMWEC's member towns."[6] The Council understands that the Company did not have the fully compiled 1980 Census results in preparing this Forecast, but even the 1970 data causes one to question the validity of this assumption.[7] Table 2 contrasts average household income for each MMWEC member town (by forecast group) and the statewide average from the 1980 Census. The table shows that only four MMWEC towns had income levels below that of the state average, while the remaining twenty-nine towns had income

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5 Penetration is defined as the percentage of new homes opting for an appliance, in contrast to saturation, which reflects the percentage of all homes with a particular appliance.

6 Forecast, p. II.B.6.

7 Exhibit DD-3.

levels above the state average. We cannot concur that the statewide distribution is a close approximation, and will not accept this assumption in future forecasts.

Even if MMWEC had employed town-specific income distributions weighted for each town within a group, we would still be concerned with the remaining problem of aggregation bias. For example, average household incomes in Group II range from a low of $15,452 in Chicopee to a high of $27,702 in Hingham. The quadratic and loglinear functional forms of the saturation/income functions used in the NEPOOL model will yield entirely different trends depending on where a town starts with respect to its initial income distribution.[8] Therefore the model's specification and MMWEC's current grouping procedure are inconsistent. Recognizing that 33 separate forecasts of saturation trends may not be computationally efficient, the Company should strive to group towns according to characteristics which are consistent with the model used and provide reliable forecast results. Socio-economic similarities are an important consideration in this regard.

° <u>The Use of NEPOOL saturation/income functions</u> - The equations developed by NEPOOL for each state were estimated from 1970 Census data. The data are now 13 years old and may not reflect saturation/income relationships in the 1980's. MMWEC should investigate, with the NEPLAN staff, the possibility of updating these equations with the latest Census data.

° <u>The NEPOOL electric space heat penetration methodology</u> - This methodology accounts for the expected life-time operating cost

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8 See: NEPOOL Load Forecasting Model Documentation, Technical Chapter 1, Residential Power Submodule, Oct., 1981, pp. 10-18.

Table 2

Mean Household Income for MMWEC's Member Towns in 1980[1]

	Town	Mean Household Income (1979$)
Group I	Groton	$22,492
	Holden	24,063
	Mansfield	20,942
	Paxton	27,514
	Templeton	18,144
Group II	Belmont	23,134
	Boylston	22,200
	Chicopee	15,452
	Danvers	21,903
	Georgetown	21,261
	Hingham	27,702
	Holyoke	12,349
	Hudson	21,931
	Littleton	23,384
	Middleborough	15,834
	Middleton	21,349
	N. Attleborough	19,039
	Shrewsbury	21,304
	Sterling	21,804
	Wakefield	21,164
	W. Boylston	22,721
	Westfield	19,746
Group III	Ashburnham	19,795
	Braintree	22,638
	Hull	17,171
	Ispwich	20,640
	Marblehead	23,982
	Merrimac	18,226
	Peabody	20,687
	Princeton	24,281
	Rowley	19,748
Group IV	Reading	25,796
	S. Hadley	19,513
	Massachusetts Avg.	17,575

1 From the 1980 U.S. Census.

differentials between oil and electric heat and also accounts for the availability of natural gas. Saturations of electric space heat are predicted to rise from a present 6% to just over 7% in 1995 in MMWEC's member towns.[9] Given the important nature of this element of the residential forecast, MMWEC should consider the development of its own methodology. In doing so, the Company would not be forced to make such speculative assumptions as the availability of natural gas in MMWEC towns being twice that as the state as a whole.[10] The development of a methodology tailored to MMWEC's towns and the available data would increase confidence in these projections.

° <u>Other Appliance Saturations</u> - MMWEC should evaluate the applicability of time trends adopted by NEPOOL in projecting the saturations for "other appliances". This evaluation should consider the reasonableness of these projections in light of MMWEC staff's knowledge of trends evident among member towns. Electric water heating is a prime candidate for such an evaluation.

3. <u>Appliance Use Projections</u>

The appliance use component is a critical element of the NEPOOL Residential Model. Problems may exist in representing local consumption with borrowed data. In a recent decision the Council rendered a thorough analysis of the appliance use procedure, so we will only highlight those points here. COM/Electric, (No. 82-4, 9 DOMSC 309-317, 1983).

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9 Response to Staff Information Request R-6.
10 Forecast, P. II.B.8, and Response to Staff Information Request R-6.

The basic problem extends from the fact that the annual appliance use estimates in the NEPOOL data base have been gleaned from studies encompassing a broad range of time-periods, geographic locations, and household characteristics. For example, the dishwasher appliance use estimate is derived from a study of 15 households in Dallas, Texas over the 1955-1957 period.[11] Most of the studies occurred during the 1950's and 1960's outside of New England and are not demonstrably applicable to MMWEC's members.

MMWEC, as is standard procedure with the NEPOOL model, has calibrated these appliance use estimates to each town based on its 1980 actual residential sales. This procedure involves taking the base-year 1980 appliance saturation estimates (from MMWEC's survey) and multiplying them by actual 1980 customer counts to yield total estimated appliances in each town. This product times the appliance use estimates from the NEPOOL data base yields estimated 1980 consumption by town. The estimated total is divided by actual sales to obtain an "adjustment factor".[12] The initial appliance use estimates are then calibrated by these factors so as to yield actual 1980 sales.

The problem with this procedure is that simply allocating that error evenly across all appliances for the base year may not yield reliable forecasts of use by appliance. For some towns the initial error is sizable.

Seeing that actual appliance use, short of expensive submetering, cannot be known, it behooves MMWEC to review the underlying socio-economic characteristics of the NEPOOL data for its applicability

11 NEPOOL Documentation, op. cit., Technical Chapter 6, Use Profiles, p. 11.

12 Response to Staff Information Request R-1.

to the MMWEC towns. In doing so MMWEC should review other sources of the same data, and concentrate on the most energy intensive appliances. The Second Condition addresses this issue.

The last procedure of concern in the residential forecasting methodology is the use of NEPOOL's price elasticities to adjust future appliance usage levels. We praise the Company for its recognition of this important effect, but we will not, however, accept the NEPOOL elasticities without verification of their applicability for MMWEC's members. The Council is aware of the tremendous difficulty in obtaining reliable estimates of price elasticities for each residential end-use. We will therefore only direct the Company to conduct an aggregate residential elasticity study for its members at this time. The third Condition incorporates this directive.

C. The Commercial and Industrial Forecast Methodology

Industrial and commercial sales are forecast to grow at the most robust pace for MMWEC's members, 4.2% and 3.0% per year respectively. Over this same time period, 1981-1991, residential sales are forecast to grow at the considerably slower rate of 0.8% per year.

MMWEC has employed a newly developed methodology for both the commercial and industrial sectors in this Forecast. The pooled cross-sectional econometric methodology developed by MMWEC is an innovative approach to forecasting and a tremendous improvement over past efforts with these sectors.

The new methodology explicitly accounts for changing prices of electricity and competing fuels, as well as for other structural variables that drive commercial and industrial energy use. The nature of this methodology has vastly improved the reviewability of the forecasts, and we further find the overall methodology to be appropriate for MMWEC at this time. The Council's following analysis therefore focuses on improving the reliability of MMWEC's commercial and industrial forecasts with the use of the Company's new methodology. Our fundamental concerns lie again in the area of potential forecast bias due to the town groupings utilized, and with the forecasts of the explanatory variables. In addition to delineating specific problem areas, we make several suggestions aimed at improving the reliability of the forecasts for these sectors.

1. Town Groupings

For the purposes of residential forecasting, MMWEC, as previously discussed, grouped towns according to their projected electricity prices. For commercial and industrial forecasting, MMWEC again classifies towns into three different groups. Rather than price, the towns are now grouped on the basis of percentage industrial sales in 1980.

For example, eleven towns fall into the category of industrial sales being less than or equal to 15% of total sales in 1980. A separate commercial and industrial econometric model is then estimated for this group, and is then used to project commercial or industrial sales for each individual town. The other two group classifications are: industrial sales between 15 and 30%, and industrial sales greater than 30% of total. Separate commercial and industrial models, estimated for each of the three groups, are used to forecast commercial and industrial sales for the 33 members.

A basic problem for MMWEC is that for single towns sufficient data do not exist over a period of time, nor in cross-section, to reliably model its commercial or industrial sales. MMWEC, in combining the available data for several towns in a pooled cross-sectional format, has developed a practical and creative solution. Grouping towns and pooling data, however, as discussed with the residential sector, should proceed on a well founded basis. In our view, the percentage industrial sales classification scheme is simplistic and may yield biased results for individual towns within a group. The nature of this concern is illustrated through Table 3 that contrasts historical and projected commercial and industrial forecasts for each town, for each group, and the system total (with the exceptions footnoted).

Table 3 illustrates several points that should be considered when grouping towns. Commercial and industrial sales have grown (and declined) at very different rates within MMWEC's member towns, and these rates vary considerably within MMWEC's present classification scheme. For example, annual growth in commercial sales in Group I has varied from a high of 8.8% in Merrimac to a low of 2.2% in Ipswich. It is obvious that despite the fact that these two towns have exhibited divergent consumption patterns, they still fall into the category of "less than (or equal to) 15% industrial sales in 1980".

It may be that the model and groupings specified by MMWEC are capable of capturing the differences that led to these divergent growth patterns. In this instance, however, the forecast predicts that Ipswich's commercial sales will exceed Merrimac's over the next decade. In light of the historical evidence, this is not an immediately intuitive result. Historical growth patterns should therefore be considered, along with the percentage of total sales in a given time period.

Another parameter that warrants consideration when grouping towns is the potential for further growth beyond that experienced historically. Land availability, zoning, water, sewerage, labor and related

Table 3

Historic and Projected Commercial and Industrial Electricity Sales for MMWEC's Members (Average Annual Growth Rates)[1]

	Town	Commercial Sales 1970-1981	Commercial Sales 1981-1991	Industrial Sales 1970-1981	Industrial Sales 1981-1991
Group I	Belmont	2.7%	2.4%	.5	3.1
	Georgetown	4.0	2.0	2.5	2.1
	Groton	5.0	1.7	11.6	2.8
	Holyoke	6.1	2.5	2.8	1.5
	Hull	3.6	0.9	11.9	-12.1
	Ipswich	2.2	2.2	- 1.8	3.4
	Marblehead	3.5	1.8	3.5	2.9
	Merrimac	8.8	1.5		
	Paxton	4.2	2.3	1.6	2.3
	Princeton*				
	W. Boylston	8.5	2.3	- 4.8	4.0
	Group I	5.5	2.3	1.1	2.1
Group II	Boylston	6.7	2.9	6.4	2.9
	Braintree	4.6	3.8	- 1.6	4.3
	Chicopee**	-3.7	3.8		
	Hingham	5.3	2.7	8.5	2.6
	Middleboro	5.3	4.1	6.6	2.2
	N. Attleboro	0.1	3.3	5.3	2.6
	Rowley*				
	Shrewsbury	2.4	4.0	3.5	6.3
	Sterling	7.4	2.7	9.3	3.4
	Group II	0.6	3.8	3.4	3.5
Group III	Ashburnham	-3.4	2.8	4.3	3.4
	Danvers	-0.5	4.2	5.7	3.1
	Holden	4.4	2.7	5.7	3.6
	Hudson	3.3	2.3	9.2	8.7
	Littleton	11.9	2.7	5.9	16.3
	Mansfield	-0.6	1.6	12.6	3.1
	Middleton	5.9	2.0	10.6	3.0
	Peabody	1.0	2.7	2.8	3.3
	Reading	-1.2	3.2	6.0	3.0
	S. Hadley	3.3	3.3	1.4	3.1
	Templeton*				
	Wakefield	4.4	3.1	-1.0	3.8
	Westfield	7.6	3.1	1.0	4.1
	Group III	4.7	3.0	5.1	4.4
	MMWEC	2.6	3.0	4.6	4.2

1 Growth rates are derived from 1970 sales data reported in MMWEC Exhibit D-1 and 1981-1991 data reported in Table III-1 of the Forecast.

* Indicates that some historical data was missing, so these towns were dropped for purposes of consistency in comparisons, and data for these towns are not reflected in Group or MMWEC average growth rates.

** Chicopee does not distinguish between commercial and industrial customers. All sales are included under the commercial classification in this table.

factors might be used to develop a "growth potential index" for each town. In this manner, MMWEC could add a foreward looking perspective to its forecasts beyond that usually provided with historically based regression analysis.

MMWEC should also consider separate classification schemes for commercial and industrial forecasting. The percentage industrial sales, or other methods directed at establishing industrial homogeneity across towns, does not necessarily establish commercial homogenity.

Lastly on this subject, we raise a few further examples of counter-intuitive forecast results that may be due to grouping, the structure of the model, or the forecasts of the explanatory variables. We recognize the pitfall of over-reliance on intuition in interpreting forecast results, but it is also a mistake to loose sight of logical expectations within the larger quantitative framework.

Group I towns experienced the most rapid commercial growth over the 1970-1981 period (5.5% versus 0.6 and 4.7) but these towns are forecast to have the slowest commercial growth over the forecast period (2.3% versus 3.8 and 3.0). Hull's industrial sales grew at nearly 12% per year over the historical period, and are now forecast to decline at a similar rate. The same relationship exists for West Boylston's industrial sales, Chicopee's combined commercial/industrial sales, and to a lesser degree for Ashburnham's commercial category. The forecast of a reversing trend, but in these cases from high growth to low, is also evident for Merrimac's commercial sales, Littleton's commercial sales, and the industrial sales of Groton, Mansfield, and Middleboro.

The Council recognizes that the closing or opening of a major commercial or industrial facility can make such comparisons at the town level misleading. MMWEC did apparently make forecast changes to recognize discrete known load changes for some towns, but did not include these changes in the forecast documentation. In future filings, we expect MMWEC to include such documentation.

2. Specification of the Models

The industrial model is an econometric specification of the general form:[13]

Industrial Electricity Sales = f (oil price, natural gas price, electricity price, gross state product, manufacturing employment)

The equations were estimated for each of the three groupings previously described using 1970-1980 data with generally good explanatory power.[14] MMWEC selected these variables using "an exploratory and iterative process" from a larger set of candidate variables.

The commercial model is a similar specification of the general form:[15]

Commercial Electricity Sales = f (oil price, natural gas price, electricity price, total town payroll, gross state product, degree days)

Again, data for each town over 1970-1980 were used and the explanatory power of these equations was very good.[16]

The Council is very pleased with MMWEC's thorough documentation on the specification of the commercial and industrial models, their theoretical justification, and the selection process by which some variables

13 For Group I, the variables included oil price, gross state product, and electricity price only. For Group II, all variables except for gross state product were used. For Group III, manufacturing employment was excluded.

14 The R^2 statistics were .94, .94, and .89 respectively.

15 For Group I, town payroll, oil, price, electricity price, and gross state product were used. For Group II all variables except gas price were used. For Group III, degree days, electricity price, and town payroll were used.

16 The commercial R^2 statistics were .99, .99, and .91, respectively.

were tried but rejected. The pooled cross-sectional approach to estimating these equations is sophisticated and evidences that MMWEC's staff is now approaching demand forecasting in a commendably rigorous manner. We laud the Company for its noticable improvements in this regard.

With regard to the specific choice of variables used in the models we have two comments at this time. We expect, however, that MMWEC's further work with town groupings will probably result in a different set of final forms.

Firstly, the oil price apparently used is for number 2 heating oil. Given the reliance of commercial and industrial customers on the heavier fuel oils (no.s 4, 5 and 6) those prices would probably be a more suitable indicator. Our second concern is with the degree day variable and is given attention in the next section.

3. Forecasts of the Explanatory Variables

MMWEC has relied upon largely external sources for forecasting the explanatory variables in its commercial and industrial equations. Given the nature of these variables this is a common and practical solution. In such a case, we look to the demonstrable applicability of these often statewide or national proxies for the Company's service area in question. The burden of demonstrating applicability lies with the Company.

An exceedingly important variable in the commercial and industrial equations is gross state product. This variable is used in four of the six forecasting equations. Furthermore, in the three industrial equations, the estimated "elasticity" on GSP ranged from .97 to 1.43.[17] This implies, for example, that for every 1% increase in gross state

17 Forecast, p. II.B.34.

product a 1.43% increase in Group II's industrial sales will result.[18] It follows that an accurate gross state product forecast will be a major determinant of the industrial, and to a lesser degree commercial forecast accuracy.

MMWEC, in the present forecast, has relied upon NEPOOL's forecast of total personal income for Massachusetts to predict gross state product. MMWEC has also relied upon NEPOOL for forecasts of the Consumer Price Index, fuel oil prices, natural gas prices, total town payroll and employment. MMWEC should continue to review these forecasts to be certain that they are the best available for its forecasting purposes with consideration of the costs and reliability of alternative sources.

The electricity price and degree day variables were both projected internally. The singular concern we have with these projections lies with the degree day forecast. This variable is actually an interactive term of degree days times the number of commercial customers as presently specified. MMWEC, to project this variable, assumes that the number of commercial customers will grow according to the historic relationship between the numbers of residential and commercial customers. First, we see no need to complicate the degree day variable in this manner. Second, the net result of assuming constant "normal weather conditions" and parallelling commercial customer growth with residential is to add a

18 This result is difficult to interpret. Assuming the model is correctly specified and the coefficient is correct, this could indicate a greater than average share of industry in the state expands in Group II towns, or that industry expansions in these towns is more electricity intensive, or that industrial customers in these towns are energy inefficient, or that fuel switching is occurring.

trend component to the model which has no apparent basis.[19] The Council will not accept this assumption in future filings without sufficient justification for its inclusion. If MMWEC continues to adopt this conceptual approach, it should develop a more rigorous approach to forecasting the number of commercial customers.

D. Municipal Sales, Losses and "Other" Forecasts

Municipal sales comprise approximately 5.5% of total energy requirements for the MMWEC members. Sales are projected to grow at an annual rate of 0.4% over the forecast period. MMWEC has developed an econometric model for general municipal use and another for street lighting. We find this to be an acceptable methodology at this time, and a well documented section of the Forecast. One suggestion for improving future forecasts is to continue efforts directed at minimizing the serial correlation indicated by the low Durbin-Watson statistics on the forecasting equations.[20] The present coefficients on the forecasting equations may not be the best "unbiased" estimates.

Losses, unaccounted for, and company use represent a significant component of each member's total energy requirements ranging from a low of 5.6% in South Hadley to a high of 15.6% in Ipswich.[21] MMWEC has projected this category based on the historic means for 24 towns, and alternative values that still fall within a 95% confidence interval around the mean for the remaining towns.

19 The historic data presented by MMWEC, Forecast - P.II.B.74, shows considerable fluctuation in the residential to commercial customer ratios in some towns. For example, over 1970-1980 the ratio declined from 34.08 to 21.38 in Paxton while it rose from 8.53 to 14.41 in Hull. Overall, the coefficient of variation is 5.6%.

20 The Company has indicated that corrective procedures were attempted, but not used (Response to Staff Information Request M-4).

21 1980 data from MMWEC Exhibit M-5.

Our concern with the losses category does not lie with the projection method per se, which we find acceptable, but with the magnitude and considerable historic variation evidenced in some towns. In general, losses, unaccounted for, and company use comprise about 7-10% of a utility's total energy requirements depending of course on the Company's generation and distribution system. MMWEC would well serve those members whose historical averages are higher than this range, along with those that show a trend towards increasing losses, through a loss-reduction study directed at efficiency gains in these areas. The towns of Georgetown, Groton, Hingham, Holden, Hudson, Hull, Ipswich, Paxton, Princeton and Reading are prime candidates for such a study. Conservation measures within the distribution systems for these towns may offer considerable savings for their ratepayers.

The "Other" class represents about 1% of the total and consists primarily of private area lighting combined with Ashburnham's and Hudson's seasonal customers. This class is held constant over the forecast period.

E. The Peak Load Forecast

MMWEC forecasts peak loads based on average historical load factors for each member. These load factors applied to the energy forecasts provide the simple transformation to peak forecasts. We find this to be an acceptable methodology in this Forecast, but we expect MMWEC will begin to reflect initiated load management programs in future filings or to show evidence that historical averages are satisfactory predictors in light of recently experienced load patterns.

Peak load is predicted to grow for the system at an annual rate of 2.5% over the 1981-1991 period, the same rate as total energy requirements.

IV. ANALYSIS OF THE SUPPLY PLAN

Since May, 1982 when the current MMWEC Supply forecast was submitted, the projected costs and availability of planned, large scale, supply purchases have changed dramatically. The events of the past six months regarding the Seabrook units have made previous staff analysis of the MMWEC supply plan obsolete.

The EFSC hearings scheduled to review the economics of Seabrook II have now been made moot by MMWEC's vote to cancel the second unit.[21A] At the same time, the projected cost increases have made the viability of Seabrook Unit 1 a matter of some concern. These factors taken together with other events have rendered the current forecast supply out of date and thereby deficient.

For these reasons, the Council will not issue a supply side forecast decision that addresses the feasibility and appropriateness of various new large scale supply options. The Council takes note here, however, of a critical supply issue: MMWEC projections indicate that five towns - Hudson, Littleton, Princeton, Shrewsbury, and Templeton - will experience supply deficiencies by 1986/87. (MMWEC Exhibit SS-2) If Seabrook II is removed from MMWEC's supply plan, several more towns are projected to experience deficiencies by 1990. If Seabrook I is removed from the supply plan, MMWEC's projections show a systemwide shortage in 1988. (See Table 4). We hereby direct MMWEC to file with the Council by March 1, 1985 a revised and updated supply plan in its next forecast supplement that addresses these projected and potential

21A. See Appendix A.

TABLE 4[1]

MMWEC - Comparison of Projected Resources and Requirements
(megawatts)

	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Winter Peak	752.2	771.4	789.5	808.4	831.0	853.4	877.0	901.2	925.3	948.4	969.0	990.3	1012.0
Reserves %[2]	16	17	17	20	22	22	21	24	24	23	23	23	23
Peak Plus Required Reserves	854.0	882.8	903.6	945.4	990.2	1018.5	1038.8	1093.8	1123.4	1143.2	1168.5	1194.7	1121.3
Existing Supply	1240.1	1243.7	1097.7	1058.0	1025.6	921.7	925.0	918.4	918.7	920.0	920.2	920.4	920.6
Millstone III					70.7	70.7	70.7	70.7	70.7	70.7	70.7	70.7	70.7
Seabrook I					120.5	120.5	120.5	120.5	120.5	120.5	120.5	120.5	120.5
Seabrook II											120.5	120.5	120.5
Total Supply	1240.1	1243.7	1097.7	1058.0	1216.8	1112.9	1116.2	1109.6	1109.9	1111.2	1231.9	1232.1	1232.3
Excess (Deficiency)	386.1	360.9	194.1	112.6	226.6	94.4	77.4	16.0	(13.5)	(32.0)	66.4	37.4	11.0

270

1. From MMWEC Forecast and Exhibit SSS-7.
2. Reserve percentages are estimates for NEPOOL by MMWEC and are only applied to that portion of the load not served by contract demand.

deficiencies and indicates how MMWEC intends to ensure a reliable supply of electricity for its members. This supply plan should include all aspects of existing or proposed nuclear, coal-fired, imported or other large scale power supply options, as well as small scale and renewable supply options, conservation and load management.

The following sections address MMWEC's progress in developing small scale and renewable supply options, particularly cogeneration, hydroelectricity, conservation, and load management. While it is impossible to accurately assess the relative costs and benefits of these supply options in isolation, the Council believes that small scale and conservation "supply" may provide diversification and cost benefits that warrant a separate review in this decision.

A. Cogeneration and Renewable Resources

The Forecast includes two existing facilities which use renewable sources of energy (hydroelectric, solar, wind, biomass, or solid waste), and are projected to provide capacity to three MMWEC members systems throughout the forecast period. This long term renewable capacity totals 2800 kw, including Holyoke's pool dispatchable 2600 kw hydro facility and two 100 kw shares of privately owned Webster Hydro contracted by Holden and Princeton. For 1982/83 only, the forecast also shows purchases by Holyoke and Middleboro of 6000 kw and 3000 kw, respectively, from the Northfield Mountain pumped storage facility.

In the area of customer owned capacity, member systems in Peabody and Danvers report a total of 5700 kw of co-generating capacity in operation, of which 4500 kw is dual fueled oil/gas and 1200 kw is oil fired. Another 3000 kw of available co-generating capacity in Hingham is reported as inactive. Customer-owned wind generating capacity, located in Ashburnham, North Attleboro, Princeton, and Reading, totals 45 Kw.

While the forecast includes no proposed firm capacity in renewables, the Council recognizes that MMWEC has made a considerable effort in studying hydropower development potential. MMWEC staff has also provided expertise and recommendations as opportunities arose concerning a variety of renewable resource technologies and projects of interest to its members.

Table 5 summarizes the numerous renewables projects currently and formerly under study by MMWEC and its member systems.

Of particular note in Table 5 are the several large hydropower projects (over 5 mw) which are no longer under active study by MMWEC. Emphasizing new and previously breached dam sites, the projects have involved high economic and environmental uncertainties typical of projects of that size and capital intensiveness. While no longer under active consideration, MMWEC recognizes, and the Council agrees, that some of the projects merit further watching -- for example the Stillwater Bridge project, with its relatively attractive economics.

Table 5 also provides examples of private renewables/cogeneration capacity which MMWEC member systems have been interested in using, but for which an acceptable agreement could not be reached. MMWEC and its member systems did not agree to purchase any of the energy (11.27 Mw) available under their option with Boott Mills, which expired July 10, 1983. And, despite the interest of 12 MMWEC systems in 4.57 mw of cogeneration capacity from the proposed FIBREX project, the developer opted for a contract with another utility able to take the project's full capacity of 8.25 mw.

Table 5

RENEWABLES AND COGENERATION PROJECTS EVALUATED FOR MMWEC

Project Name and Type	Project Participation Type	Project Participation Member/3rd Party Participants	Capacity (Kw)	Project Status/Disposition
Stillwater Hydro	A	Undetermined members	11,000	Prel. permit withdrawn (environmental opposition)
Warehouse Point Hydro (in Connecticut)	A	Undetermined members	50,000	Prel. permit withdrawn (high cost and environmental opposition)
Windsor Locks Canal Hydro (in Connecticut)	A	Undetermined members	2,500-3,000	Prel. permit withdrawn (high cost)
Millers Hydro (5 dams)	A	Undetermined members	5,600	Prel. permit withdrawn (high cost)
Moores Falls Hydro (in N.H.)	B or C	Essex Development Associates; undetermined members	15,000 (50% option)	Prel. permit withdrawn (high cost)
Boott Mills Hydro	B/C	Boott Mills; undetermined members	23,000 (49% option	Joint participation agreement discontinued (legal problems); purchase agreement for up to 49% capacity declined.
Collins Dam Hydro	A/C	Swift River Co.; undetermined members	1,400	MMWEC prel. permit withdrawn (small, marginal economics); Swift River investigating sales agreements with various utilities.
Burlington Electric Dept. wood-fired plant (in VT)	B or C	Burlington Elec. Dept.; undetermined members	50,000 (undef. share)	Not currently recommended for members (high costs in early years); under evaluation.
Plainville "Clean Communities" refuse to energy plant	A(generator) C(steam)	"Clean Communities" provides steam; undetermined members	70,000	Refuse Facility sold to RESCO (wheelabrator-Frye); contract signed with NEPCO.
Millers Falls wood-fired plant	C	NEPCo; undetermined members	N/A	Not recommended for members (high cost); project has not proceeded.
Greater Springfield Refuse Burning	C	Carmen Chevie; undetermined members	12,000	Negotiations between developer and Monsanto; MMWEC has discussed purchase.

Table 5, page 2

RENEWABLES AND COGENERATION PROJECTS EVALUATED FOR MMWEC

Project Name and Type	Project Participation: Type	Project Participation: Member/3rd Party Participants	Capacity (Kw)	Project Status/Disposition
FIBREX cogeneration with wood waste supplemental	C	FIBREX; twelve members	8,250	Member interest in only a portion; contract signed with NU.
Holyoke Hydro	D	Holyoke owns	2,600	Operating
Webster North Village Dam Hydro	D	Webster Hydro; Princeton and Holden purchase	200	Operating, with purchase agreement.
Chicopee Falls Hydro	D/C	Chicopee and Swift River Co.; undetermined members	2,500	Chicopee filed and later leased development rights to Swift River; MMWEC has discussed power purchase from Swift River.
Methuen Falls Hydro	D	Spicket River Corp; Groton purchase	357	Project still pending (legal dispute with abuttor); no sales agreement.
Conway Dam Hydro	D	Town of Conway; unnamed member purchase	285-475	Environmental Impact Report under preparation; no sales agreement.
Princeton wind generator	D	Princeton Light Dept.	495	Private developer bids being solicited.
Hadley Falls Hydro (Units 2, 3)	D	Holyoke	30,000	Holyoke lost to competing license application by site owner NU.
Braintree refuse-to-energy plant	D	Braintree	N/A	Failed 2/3 town meeting vote.
Centennial Island Hydro	D	Mass Bay Power Co.; Groton purchase	675	Groton decided not to participate (cost); project is on hold.
Peabody Solar	D	Peabody	8	Start up in 1983.

A - MMWEC developer; member contracts
B - MMWEC joint developer with third party; member contracts
C - MMWEC purchase from third party; member contracts
D - Member developer or purchase

Given the desirability of renewables and cogeneration in diversifying supply sources, the Council believes that MMWEC and its member systems must have the flexibility to take fuller advantage of opportunities such as the above. There may be opportunities, for example, to pool member losses and gains to achieve project thresholds while maintaining net system benefits. New institutional or contractual arrangements, backed by new legislation if necessary, should be considered to give MMWEC greater flexibility in negotiating small power producer contracts. The Renewable Energy Resource Fund, provided in MMWEC's 1979 power sales agreements with its members for "Project 6", is one past example of MMWEC members acting collectively to set aside funds for renewables.

MMWEC has provided some support for renewables development on a member level, including member referrals for small producers, project analyses requested by member systems, and inventory work on potential wind generator sites. The Council nevertheless, strongly encourages MMWEC and its member systems to establish overall goals and a comprehensive planning approach to support both member projects and purchases from small producers. The referrals process for small producers could be improved through increased publicity and the use of informational materials on likely rates, contract terms and procedures.

As mentioned above, co-generation within the member communities has been taking place in Peabody (Eastman Gelatin), Danvers (Danvers State Hospital), and Hingham (Merriman Co.). In addition Holyoke provides district steam heating from its electric power plant. By the end of 1983, 1500 Kw of new wood waste and oil fired capacity is planned at Baldwinville Products in Templeton. These communities -- which are among 15 MMWEC communities expected to experience increases of over 10,000 MWH in industrial usage or over 25,000 MWH in commercial - industrial usage between 1981 and 1991 -- are commended for showing early progress toward increased co-generation.

The Council believes MMWEC and its member systems must be more aggressive in encouraging co-generation in their own service area(s), as well as in pursuing opportunities outside member service areas. Despite claims in the forecast of limited industry suitable for co-generation, it is noted that MMWEC's systemwide percentage of total 1981 sales for the industrial class (33 percent)[22] ranks second among the six major Massachusetts utilities.[23] The percentage of total 1981 sales for the combined commercial/industrial class (58 percent) ranks fifth, but is within five percentage points of the other major utilities except Boston Edison. In addition, the projected average annual 1981-1991 growth in industrial usage is 4.3 percent, while that for commercial-industrial growth is 3.9 percent.

The Council expects that MMWEC will develop a more comprehensive and aggressive program for cost-effective renewables and co-generation development. Condition 5 also addresses this issue.

B. Conservation and Load Management

The Council has repeatedly stressed the value of conservation and load management strategies as part of an effective overall supply plan. In our last review of MMWEC's forecast we gave this important matter our focused attention. The Council stated "MMWEC had a system load factor

22 The forecast indicates that some member communities include various commercial use classes in industrial use.

23 Mass. EFSC, The Electric Industry in Massachusetts, March 1983. The utilities are Boston Edison, COM/Electric, EUA, MMWEC, NEES, NU.

equal to 56.4% in 1978 and is projecting a value of 55% in 1988.* The Council believes that this load factor is unnecessarily low and that MMWEC's members should be concerned about it. ...If MMWEC's chief service to its member municipalities is the planning and acquisition of low cost and reliable bulk power supplies, it is consistent with those goals that the system load factor be brought under control. ... The Council believes that MMWEC's members should be implementing load management initiatives at a faster pace than is evident from the record." (5 DOMSC 89-90) To this end the Council directed MMWEC in its Condition 7 and each member explicitly in Condition 10 to perform the following:

Condition 7 (EFSC 79-1). That MMWEC shall examine the feasibility of studying the implementation of direct and indirect load management initiatives by MMWEC member systems. The results of this study should be communicated to the member towns for their consideration. Town responses to this study, as well as documented evidence of similar initiatives which may exist or be proposed, shall be submitted to the Council. (See also Condition 10 below.) The study design shall include at a minimum:

I. RATE STRUCTURES THAT CONTROL DEMAND
(Primarily Efforts to shift load from peak to off-peak or to constrain on-peak load growth)
1. Interruptible rates to commercial and industrial customers;
2. Peak control rates to commercial and industrial customers;
3. Off-peak rates for all classes of hot water heating;
4. Storage electric heat rates;
5. Controlled air conditioning rates;
6. Time-of-use rates.

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* MMWEC has since reminded Council staff that the referenced load factors are non-coincident, and that the systems' coincident load factors are higher. This consideration does not, however, alter the Council's past and present belief that MMWEC should be actively pursuing cost-effective load management options.

II. DIRECT, REMOTE CONTROL LOAD MANAGEMENT INITIATIVES
1. Hot water heating;
2. Air conditioning.

Condition 10. That each and every MMWEC member system study and initiate load management programs employing rate structures and appliance controls, where such programs are cost effective and oil conserving. For load management initiatives to be considered at a minimum, see Condition 7 above. Each member shall also cooperate fully with MMWEC in the development of these initiatives and shall communicate the impacts of their load management activities to MMWEC.

In response to these conditions, the Municipal Electric Association of Massachusetts (MEAM) contracted with R.W. Beck and Associates for a load management study completed in October, 1982. All MMWEC municipals, as members of MEAM, participated in this study and MMWEC staff participated in formulating the study design.

The Council finds the study to be a meaningful and important first step. We praise the municipals for their cooperation with the Council in undertaking this significant research effort.

The Beck study analyzes groups of towns according to their supply mixes and load shapes to ascertain the cost-effective potential for load management applications. It states "The intent of this analysis is to provide guidance to the Municipals in their determination on whether to further study the feasibility of implementation of load management programs on their individual electric systems."[24]

24 Load Management Study. Municipal Electric Association of Massachusetts, R.W. Beck and Associates, October, 1982, p. I-4.

Table 6

Load Management Study Findings

Group:	A	B	C	D	E	F	G
Potential Cost-Effective Load Management Applications	Danvers Middleton Peabody W. Boylston Westfield	Braintree Mansfield Reading Templeton	Georgeton Groton Hull Marblehead Paxton Princeton	Ashburnham Hingham Holden Hudson Ipswich Littleton Rowley	Boylston Middleborough N. Attleborough Shrewsbury Sterling Wakefield	Chicopee S. Hadley	Belmont Merrimac
Long-term savings from existing pumped storage hydro	yes		yes	yes	yes		
Near-term savings from peak shaving						yes	yes
Long-term savings from direct load control of peak to off-peak shifting	yes			yes			

Table 6 categorizes the principal "generic" findings of the study. Although no attempt was made to study programs tailored for the individual members, the generic findings serve as a useful indicator of where further study is warranted. The results indicate, significantly, that all MMWEC members, with the exception of those in Group B, have the potential to reduce power supply costs through load management. Chicopee, South Hadley, Belmont and Merrimac have an immediate opportunity to reduce costs principally through the displacement of purchased power from larger utilities. The other members are not predicted to have the potential for achieving cost- effective results until the Millstone and Seabrook base-load power become available to them.

Unfortunately, the study did not include some important considerations. First, only short-run variable costs of generation were considered for Groups A-E (28 of the 32 towns studied) in the cost-benefit analysis. Given MMWEC's possible need for new capacity, and the high "avoided cost" of Seabrook II, a broader definition of variable costs would be timely. For the four towns where fixed costs were considered (due to their contracts with other utilities), the results were more favorable for load management.

Second, the study did not directly evaluate commercial and industrial load management. A sensitivity analysis was conducted.

b. Response to the MEAM Study

At this time the Council has not been provided with the required responses directed in Condition 7. With the realization that the members only received the results in October, 1982 this is understandable. We do expect MMWEC and the members to fully comply with

Condition 7 by providing a formal response to this study indicating what further action is being taken. We reiterate this order as part of a broader directive in Condition 5 of this Decision.

c. The Present Commitment of the Municipals to Conservation and Load Management

The Council has had a very difficult time fully evaluating the extent of conservation and load management programs of the MMWEC members. The importance of this matter to the Council led us to ask MMWEC to survey its members during this proceeding to obtain necessary information on program description, customer participation, funding levels, and projected peak and energy savings.[25] Responses to our requests remain inadequate to properly access the municipals' performance in this regard. Funding levels, participation rates and energy and peak savings have not been provided for individual towns and program start-up dates have only been provided for a minority of programs. Rather than delay this decision pending a further effort at gathering this essential information, we will require that MMWEC present with its next filing a detailed plan for promoting and implementing cost-effective conservation and load management for its members.

The information the Council has obtained allows us to proceed with a cursory review of the municipals' progress in conservation and load management.

To date, all MMWEC members with the exception of Chicopee and Mansfield have offered audits to their residential customers. Approximately 4.8% of all MMWEC residential customers have thus far been audited.[26]

25 Staff Information Requests C-4 and CC-1.

26 Calculated from Response to Staff Information Request C-4 and based on MMWEC's 1981 customer count.

Sixteen members offer additional conservation and load management incentives such as various rate incentives, water heater timers and radio control devices. Only a few members, however, appear to be actively providing such direct services to their customers as weatherization grants or water heater wraps.

MMWEC itself has yet to take an active role in promoting or supporting conservation services for its members. The beginnings of such an effort, however, may be emerging in the newly conceived "Energy Service Planning" program.[27] The supporting information on this plan, that MMWEC has sent to the municipal managers, cites cogeneration, district heating, off-peak heat, solar heating, cable television, municipal waste use, coordination of municipal utility use and conservation and load management as possible energy services. The Company states "MMWEC is in a unique position to assist the municipal systems by providing information and technical analysis as well as coordinating the selection of energy services with power supply planning."[28] MMWEC also states that "On the basis of our limited investigation to date, we are recommending a relatively austere staff effort (approximately one person year) in the 1983 budget to assist the member systems identify possible energy services opportunities."

The Council wholeheartedly supports this concept. In our opinion, MMWEC should take a role in this regard beyond the limited effort indicated thus far. We fully concur with the Massachusetts Department of Public Utilities recent declaration:

> "In reviewing utility-sponsored conservation and load management programs, the Department has consistently held that demand management strategies can serve the same purpose as supply options for meeting customers'

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27 Letter and materials provided as an additional response to Staff Information Request C-4, April 12, 1983.

28 Letter to Member Managers from MMWEC, October 20, 1982.

> present and future needs. In this case, we reiterate our view that a company's long-term planning process should give as much consideration to conservation and load management as to energy supply alternatives (such as construction of new power plants, investment in coal conversions, or negotiations of purchased power contracts."[29]

The record in this case indicates that MMWEC has not emphasized conservation and load management on a comparable basis with the traditional supply alternatives. The select members that have been active in this regard, and especially those in the early stages of evaluating conservation and load management options, could well benefit from MMWEC's organizational support and staff expertise.

V. DECISION AND ORDER

It is hereby ORDERED that, given the points and considerations set out in the foregoing analysis, the Annual Supplement (1982-1991) of the Massachusetts Municipal Wholesale Electric Company is APPROVED, subject to the following conditions:

1. That MMWEC will report to the Council with its next filing on progress in improving the level of disaggregation of its commercial/industrial data base. The report should include a description and evaluation of past C/I sales data, a list of alternative improvements, and a description of improvements that have been made to better identify and forecast the components of the C/I load.

2. That MMWEC conduct a literature search on residential appliance use estimates, and either demonstrate the applicability and superiority of the NEPOOL data for MMWEC's members in light of this research, or address appropriate changes in the residential data base with the next filing. In doing so, MMWEC should initially concentrate on the most energy intensive appliances (range, refrigerators, freezer, water heating, and space heating).

3. That MMWEC perform an aggregate price elasticity of demand study for the residential class of its members. The study should include, at a minimum, electricity prices, prices of substitute fuels, and income. MMWEC should attempt to demonstrate the applicability of the NEPOOL residential end-use elasticities in light of this study, or implement appropriate modifications with the next filing.

29 DPU 1350, p. 135.

4. That MMWEC provide in its next forecast Supplement a comprehensive and aggressive plan to implement demand reduction programs and identify potential alternative sources of generation, including coal, cogeneration, imported power, renewables and other sources for the forecast period.

5. That the combined 2nd and 3rd Supplements to the Second Long-Range Forecast be submitted on or before March 1, 1985.

Lawrence W. Plitch (Jaup)

Lawrence W. Plitch, Esq.
Hearing Officer

On the Settlement

James M. Coyne, Lead Electric Analyst
William S. Febiger, Staff Analyst

Unanimously APPROVED by the Energy Facilities Siting Council on October 24, 1984 by those members and designees present and voting: Sharon M. Pollard (Chairperson); Joellen D'Esti (for Secretary Evelyn F. Murphy); Sarah Wald (for Secretary Paula W. Gold); Stephen Roop (for Secretary James S. Hoyte); Robert W. Gillette (Public Environmental Member); Joseph W. Joyce (Public Labor Member). Ineligible to vote: Edward H. Collagan (Public Oil Member).

30 October 1984
Date

Sharon M. Pollard
Sharon M. Pollard
Chairperson

APPENDIX A

LAW OFFICES OF
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April 12, 1984

Mr. Lawrence Plitch, Esq.
Hearing Officer
Energy Facilities Siting Council
100 Cambridge Street
Boston, MA

Re: EFSC 82-1A

Dear Mr. Hearing Officer:

In a December 19, 1983 Procedural Order in EFSC 82-1A, the Energy Facilities Siting Council ("EFSC") ruled that these proceedings are specifically limited to the economics of completing Seabrook Unit II.

> ... Therefore, these hearings are specifically limited to the only issue which the staff was unable to substantially settle with the Company, *i.e.*, the economics of completing Seabrook II. To this end, all other issues, *e.g.*, the Company's demand methodology and the question of whether any other elements of the Company's present supply plan are economically feasible, are initially beyond the scope of these hearings... Therefore, should any party desire to pursue an issue that has been tentatively agreed to by the staff and the Company in this case, they will first be required to demonstrate the relevancy of that issue to the ultimate concern of these proceedings, *i.e.*, the economics of Seabrook II.

Regarding the issues and scope of EFSC 82-1A, the EFSC ordered the Massachusetts Municipal Wholesale Electric Company ("MMWEC") "to file... its direct case on the cost-effectiveness of completing Seabrook II."

> ...The case will include its latest projections of demand, alternative generation costs and related variables... These analyses will be presented using various appropriate sensitivity tests, including high, base case and low projections for oil costs, demand projections, Seabrook II construction costs and capacity factors.

Scenario I: cancel Seabrook II on July 1, 1984
Scenario II: "Seabrook II in minimum preservation state until Seabrook I comes on line and then is completed on full construction schedule."

Thus, as can be readily seen from the above EFSC Order, the EFSC ruled that the scope of EFSC 82-1A would be the economics of Seabrook Unit II's completion.

On March 28, 1984, the MMWEC Board of Directors voted "...to take any action he [General Manager] deems necessary or advisable to accomplish the cancellation of Seabrook Unit #2 at as early a date as is possible ..., and, that staff will continue to evaluate and seek alternative means for power supply requirements." A copy of this vote is attached. At the March 30, 1984 Seabrook Joint Owners' meeting, MMWEC voted for the cancellation of Seabrook Unit II. The Joint Owners' March 30, 1984 vote regarding the cancellation of Seabrook Unit II is attached.

As MMWEC always has done 1/, MMWEC has analyzed the Seabrook Unit II economics after the Seabrook Project cost and on-line estimate of March 1, 1984. In this most recent analysis, MMWEC evaluated and monitored the cost, 2/ completion capacity and NEPOOL Support of such alternatives to Seabrook Unit II as Hydro Quebec Phase II, Point LePreau II, 3/ a generic coal plant, Stony Brook development or the conversion to gas use and load management 4/. MMWEC evaluated the costs, Joint Owners' ability to raise capital, MMWEC's credit-worthiness/financing costs, MMWEC's rate increases, economics, necessary regulatory approvals, the political situation, the Joint Owners' support and MMWEC Member

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1/ MMWEC presented an analysis regarding the completion and cancellation of Seabrook unit II to the EFSC during September and October of 1983. This analysis showed that for MMWEC at that time the completion of Seabrook Unit II would be more economic than its cancellation. In its November settlement offer, the EFSC discussed this MMWEC analysis.

2/ MMWEC used NEPOOL cost estimates for Pt. LePreau, generic coal and Hydro Quebec. MMWEC used DRI's oil projections.

3/ MMWEC also must consider becoming dependent on foreign sources of generation.

4/ MMWEC has utilized NEES's projections regarding load management. The projections being used for load management include a 10% reduction in Peak and a 6% reduction in energy usage.

support as these issues impact the completion of Seabrook Unit II. 5/ In this analysis, MMWEC utilized different scenarios regarding Seabrook Unit II's capacity factors 6/, ultimate costs 7/ and MMWEC's projected load growth 8/ in arriving at a decision regarding Seabrook Unit II.

As MMWEC presented in EFSC 82-1, its support for the minimum preservation level for Seabrook Unit II was based on MMWEC's significant capacity deficiency without the power from this Unit. As MMWEC had set forth in EFSC 82-1, its alternatives' analysis showed that the alternatives presented substantial risks. While these alternatives still involve risks, the passage of time has created a clearer picture. Given the present information, MMWEC thinks that the economic, financial and completion risk of Seabrook Unit II is greater than the comparable risks of these alternatives. Given this evaluation, as set forth in the previous paragraph, MMWEC has voted to cancel Seabrook Unit II.

Since the scope of EFSC 82-1A concerned the economics of the completion of Seabrook Unit II and since MMWEC on the basis of its aforementioned analysis has voted to cancel Seabrook Unit II, MMWEC respectfully states that no issue in controversy exists in EFSC 82-1A. An issue would exist if the EFSC or the intervenor, Attorney General's Office, disagree with MMWEC's position to cancel Seabrook Unit II. MMWEC does not think this is the case since the EFSC in EFSC 82-1 was not in support of the completion Seabrook Unit II and since at least 1979, in such cases as DPU 20055, the Attorney General has not been in support of Seabrook Unit II.

Since all parties are seemingly in agreement regarding the issue in EFSC 82-1A, the completion of Seabrook Unit II, MMWEC respectfully submits that this proceeding which has been on-going since May, 1982 be ended. As is stated in the EFSC's December 18, 1983 Procedural Order, MMWEC and the EFSC virtually reached a settlement on all issues but Seabrook Unit II. The EFSC

5/ As recent events indicate, the support for Seabrook Unit II has eroded. Such an erosion hinders the completion of Seabrook Unit II.

6/ MMWEC utilized a scenario which included a 55% capacity factor.

7/ MMWEC utilized a scenario with a Seabrook Unit II cost that is 35% higher than the current cost estimate for Seabrook Unit II.

8/ MMWEC included a scenario with a 1% growth rate. MMWEC used an updated load forecast. The EFSC supported MMWEC's load forecast methodology in EFSC 82-1.

presented this same settlement proposal on November 14, 1983. As MMWEC has stated to the EFSC in its Petition For Determination Of Jurisdiction and certain other Motions 9/, MMWEC is opposed to wasting valuable and scarce time, effort and resources. Since the issue in EFSC 82-1A is no longer in controversy, MMWEC respectfully states that the proceeding be ended and concomittantly MMWEC's Petition For Determination Of Council Jurisdiction would then be moot and not ripe. Rather MMWEC should use its limited resources in ensuring it obtains the alternatives necessary to meet the serious deficiency that exists without Seabrook Unit II being built.

Very truly yours,

Kenneth M. Barna

Kenneth M. Barna, Esq.
Ferriter & Barna, P.C.

Attorneys for the
Massachusetts Municipal
Wholesale Electric Company

KMB/sb
Enclosure

cc: all parties
Council Members

9/ See MMWEC's February 14, 1984 Motion For A Stay.

The Massachusetts Municipal Wholesale
Electric Company's March 26, 1984 vote
regarding the cancellation of Seabrook Unit II

VOTED 84-35 that the Board of Directors directs the General Manager to take any action he deems necessary or advisable to accomplish the cancellation of Seabrook Unit #2 at as early a date as is possible, and further, directs the General Manager to negotiate on behalf of MMWEC and its members, such agreements as may be necessary to assure that all joint owners can continue to finance Unit #1, and, that staff will continue to evaluate and seek alternative means for power supply requirements.

The Seabrook Joint Owner's March 30, 1984
vote regarding the cancellation of Seabrook Unit II

1. The concept, voted unanimously by the NEPOOL Executive Committee on March 23, 1984, to use a share of the savings anticipated to result from the Hydro Quebec interconnections to, among other things, assist PSNH in the cancellation of Seabrook 2, shall have embodied in a formal, written and duly executed contract; and

2. Necessary approvals of the contract referred to in Paragraph 1 above have been obtained.

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the City of Holyoke Gas and Electric Department for Approval of the 1983 Supplement to its Long-Range Forecast of Gas Requirements and Resources	)	Docket No. 83-23

FINAL DECISION

James G. White, Jr.
Hearing Officer

On the Decision:
George Aronson
Director of Technical Analysis

The Energy Facilities Siting Council ("Siting Council") approves the 1983 Supplement to the Long-Range Forecast of Gas Requirements and Resources ("Supplement") of the City of Holyoke Gas and Electric Department ("Holyoke").[1]

I. History of the Proceedings

Holyoke filed its 1983 Supplement on October 18, 1983. Holyoke provided public notice of this filing by meeting the Siting Council's posting and publication requirements. The Siting Council received no petitions to intervene, or for participation by interested persons. Holyoke filed complete and timely responses to one set of Document and Information Requests.

II. Background

In terms of total gas sendout, Holyoke is the ninth largest utility in the Commonwealth.[2] Holyoke serves approximately 6400 residential heating customers and approximately 3600 residential non-heat customers. In the 1982-83 split year, residential customers accounted for 600 MMcf of sendout representing 24 percent of total firm gas sendout. Holyoke projects this percentage will be 30 percent in 1983-84. The 1983 Supplement indicates that Holyoke served almost 500 fewer residential heating customers in the 1982-83 split year than in the 1981-82 split year, and 750 fewer than in the 1980-81 split year. Except for five large industrial customers, Holyoke projects sendout jointly for

1. Pursuant to Mass. Gen. Laws Ann. ch. 164, sec. 69G, the City of Holyoke Gas and Electric Department ("Holyoke") is a "gas company" under the jurisdiction of the Energy Facilities Siting Council. Holyoke's Second Long-Range Forecast was filed in 1981, and the First Supplement was filed on December 15, 1982. 7 DOMSC 256 (1982); 10 DOMSC 92 (1983).
2. Aronson, Report by the Energy Facilities Siting Council: The Gas Industry in Masssachusetts, at 6 (March 1983).

commercial customers and the remaining 980 industrial customers. This class of customers accounts for approximately 40 percent of total projected firm sendout. The 1983 Supplement reflects a loss of approximately 30 customers between the 1981-82 and 1982-83 split-years. The five large industrial customers account for approximately 8 percent of total firm sendout. The remainder of total sendout, or approximately 22 percent, is attributable to company use, including gas used in Holyoke's steam generating plant, and unaccounted-for gas.

III. Sendout Forecast

A. Compliance with Prior Conditions

The Siting Council's most recent decision, required Holyoke to explain further the large projected increase in the heating increment for residential heating customers. 10 DOMSC 92, 95 (1983). Holyoke has not specifically addressed this Condition in the current Supplement. As discussed below, however, Holyoke's adoption of a new sendout forecast methodology resulted in projected decreases in the heating increment for residential heating customers. Thus, the Condition, in effect, has been met.

B. Description of Forecast Methodology

In the instant filing, Holyoke, for the first time forecasts its sendout requirements using "A Simplified Approach to Forecast Gas Sales and Revenues for the Small Gas Distribution Company," as prepared by the Forecasting Subcommittee of the Statistics and Related Economics Committee of the American Gas Association (the "AGA Approach"). The AGA Approach uses historical data on base and heating use per customer and the number of customers to forecast sendout by customer class. Total firm sendout is the sum of sendout for each class and estimates of the Department's use and unaccounted-for gas.[3]

Holyoke uses actual 1982-83 sales data and the average number of customers to derive an annual use per customer. The figures for space heating use in each class are normalized to account for heating degree day data. The Department projects future sendout using the derived figures adjusted to account for the net number of projected new customers in each year, as well as a judgemental 1.5 percent per year reduction in average use per customer to account for forecasted energy conservation. Holyoke uses a split year total of 6505 degree-days to forecast normal year sendout requirements, a split year total of 6985 degree-days to forecast design year sendout requirements, and a peak day total of 68 degree-days, representing the coldest day in the last 28 years.

Table One shows Holyoke's forecast of sendout requirements for the 1984-85 and 1987-88 split years.

C. Analysis of Forecast Methodology

The Siting Council finds that the AGA Approach is an appropriate forecasting methodology for a gas utility of Holyoke's modest size. By including the AGA Approach's instructions and worksheets in its initial filing, Holyoke has submitted a Forecast Supplement that is reviewable.[4] Moreover, Holyoke indicates that it is monitoring the impacts of energy conservation and changing gas and oil prices on its customers' consumption patterns, which instills added confidence in the reliability of the projections.

3. Holyoke's internal use is comparatively large, because the Department uses gas to power its district steam system. Supplement, Sec. III at 2.
4. The Siting Council employs a three pronged test in evaluating gas forecasts. See N. Attleboro Gas Co., 10 DOMSC 159, 160 n.3 (1984).

TABLE ONE
Forecast of Sendout Requirements
(MMcf)

	1984-85 Non-heating Season	1984-85 Heating Season	1987-88 Non-heating Season	1987-88 Heating Season
A. Normal Year				
Residential Heat	164	392	158	380
Residential Non-heat	43	30	41	29
Commercial and small industrial	304	530	295	515
Large industrial	67	88	64	85
Company use and unaccounted for	349	111	348	110
Total firm sendout	927	1151	906	1119
Normal interruptibles	119	100	119	100
Total sendout	1046	1251	1025	1219
B. Design Year total firm sendout	957	1219	936	1187
C. Peak Day sendout	-	12.353	-	12.067

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

The Siting Council notes, however, that the AGA Approach, and hence, the sendout forecast, is only as reliable as the underlying data. Thus, the Siting Council encourages Holyoke to monitor customer consumption patterns, especially during periods of unusually cold or warm weather, and to report noteworthy results in its next filing. The Siting Council also encourages Holyoke to monitor the responses of large industrial customers and potential new residential heating customers to changes in gas and oil prices. Finally, the Siting Council observes the divergence in the projected numbers of customers in the last Supplement and the actual numbers reported in this Supplement and encourages Holyoke to identify the customer numbers as closely as possible with reference to Holyoke's particular knowledge of its service territory.

The Siting Council approves unconditionally the sendout portion of the Supplement.

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

Holyoke's gas supply resources and facilities remain basically unchanged since the Siting Council's last decision. 10 DOMSC 92 (1983). Holyoke purchases pipeline gas from Tennessee Gas Pipeline Company ("Tennessee") pursuant to a contract dated June 4, 1981. The original termination date of the contract is November 1, 2000, with automatic annual extensions until cancelled on twelve months written notice by either party. The contract provides for a maximum daily quantity (MDQ) of 7.875 MMcf (at 14.73 psia)to be purchased under Tennessee's G-6 Rate Schedule. Holyoke has requested Tennessee for a "buildup" in the MDQ starting in November 1984 (8.048 MMcf) and ending in November 1986. (10.220 MMcf). The current Annual Volumetric Limitation is 2787 MMcf. The gas is delivered at two citygate take stations in Hampden County.

Holyoke purchases gas from Bay State Gas Company ("Bay State") under an agreement dated October 25, 1978 as amended on June 26, 1981 and on August 23, 1982. The agreement contains an initial termination date of March 31, 1988. Thereafter, the agreement will continue in effect on a contract year basis until cancelled on twelve months written notice of either party. As amended, the agreement provides for purchase of the following quantities (MMBtu):

	Firm	Optional	Total
April-October	20,000	0	20,000
November	14,250	0	14,250
December	44,250	13,125	57,375
January	45,500	13,125	58,125
February	40,000	26,250	66,750
March	13,500	0	13,500
	177,500	52,500	230,000

Holyoke purchases the firm volumes on a take or pay basis. Holyoke elects to purchase all or any portion of the optional volumes by written notice to Bay State ten days before the beginning of the month in which the gas is to be purchased. The elected quantities become take or pay volumes.

The agreement provides that Bay State shall use its best efforts to deliver the gas by displacement at Bay State's interconnections with Holyoke on the Willimansett Bridge crossing the Connecticut River in Holyoke and on Balboa Drive in West Springfield. The maximum hourly rates of delivery by displacement at these points are 125 Mcf and 50 Mcf respectively. Holyoke requests delivery by displacement on one hour notice. In the event delivery cannot be accomplished by displacement, Holyoke can request daily delivery of one truckload of either LNG (10,000 gallons) or propane (8,500 gallons) on 24 hour notice. Bay State has the responsibility for providing the trucking service.

Holyoke has four LNG storage tanks with a total capacity of 220,000 gallons,[5] and a daily LNG vaporization capacity of 12 MMcf. During the 1982-83 split year, the total LNG sendout was 23 MMcf and the maximum daily sendout was 1.1 MMcf.

In preparation for the 1983-84 heating season, Holyoke entered into contracts with three propane suppliers.[6] Each contract provided for the minimum and maximum purchase by Holyoke of 100,000 gallons (9 MMcf) and 300,000 gallons (27 MMcf), respectively. Thus, the total firm and optional quantities were 27 MMcf and 54 MMcf, respectively. Holyoke states that it anticipates entry into contracts for the same quantities on an annual basis for the remainder of the years in the forecast period. The contracts do not provide a delivery schedule. Rather, the suppliers deliver the propane by truck from various points in New England after receiving orders from Holyoke. The contracts state that deliveries usually can be made within one day.

Holyoke has a propane storage and vaporization facility with a storage capacity of 201,000 gallons (18.4 MMcf), and a design daily sendout of 2.4 MMcf. The 1982-83 split year total propane sendout was 33 MMcf and the maximum daily sendout was 0.8 MMcf.

V. Analysis of Requirements and Resources

During a normal weather year, Holyoke must meet the sendout requirements of its firm customers. Holyoke also maintains certain sales to interruptible customers. During a design year Holyoke must

5. Holyoke has no plans in the foreseeable future to install its fifth LNG storage tank. Thus, the Siting Council specifically does not address its earlier decision regarding the fifth tank. See 1 DOMSC 79 (1977).
6. Holyoke annually receives public bids for its propane supply. Thus, two of Holyoke's propane suppliers for the 1983-84 heating season were different than in the preceding years.

meet the additional temperature sensitive requirements of its firm customers. Holyoke plans to meet these requirements with its optional quantities of LNG and propane, and if necessary, by redirecting sales from interruptible to firm customers.

Tables Two and Three set forth Holyoke's supply plans for normal and design years throughout the forecast period. In a normal year, Holyoke depends primarily on Tennessee pipeline gas to meet its requirements. Holyoke plans to take 1134 MMcf of Tennessee gas in each heating season during the forecast period, representing approximately 97 percent of the available Tennessee pipeline supplies. Holyoke also plans to use its firm contract quantities of LNG and propane during normal heating seasons.

In the normal non-heating seasons throughout the forecast period, Holyoke plans to use Tennessee pipeline gas and its firm quantities of Bay State LNG. Holyoke projects that its purchases from Tennessee will be below the available supply of 1610 MMcf.

During design heating seasons, Holyoke plans to meet requirements above those in a normal heating season with the optional contract quantities of propane and LNG. If necessary, Holyoke can reduce its sales to interruptible customers in order to serve its firm customers. In design non-heating seasons, as indicated on Table Three, Holyoke clearly has sufficient supplies.

The Siting Council makes several observations concerning Holyoke's supply plan during heating seasons. First, the Siting Council has examined Holyoke's reliance on best efforts displacement delivery of Bay State gas. Holyoke has indicated that it has experienced no instances when Bay State was unable to provide the requested service.

Table Two
(MMcf)

	Normal Heating Season				
	83-84	84-85	85-86	86-87	87-88
Requirements					
Firm Requirements	1165	1151	1140	1129	1119
Interruptible Sales	154	168	179	190	200
Total	1319	1319	1319	1319	1319
Resources					
Tennessee G-6	1134	1134	1134	1134	1134
LNG (displacement)	138	138	138	138	138
(truck)	20	20	20	20	20
Propane	27	27	27	27	27
Total	1319	1319	1319	1319	1319

	Normal Non-Heating Season				
	83-84	84-85	85-86	86-87	87-88
Requirements					
Firm Sendout	933	927	920	914	906
Interruptibles	119	119	119	119	119
Total	1052	1046	1039	1033	1025
Resources					
Tennessee G-6	1032	1026	1019	1013	1005
LNG	20	20	20	20	20
Total	1052	1046	1039	1033	1025

Table Three
(MMcf)

	Design Heating Season				
	83-84	84-85	85-86	86-87	87-88
Requirements					
Design Firm	1231	1219	1206	1195	1187
Normal Firm	1165	1151	1140	1129	1119
Excess Required	66	68	66	66	68
Resources					
Additional Tennessee G-6	43	43	43	43	43
Propane	54	54	54	54	54
Bay State LNG	53	53	53	53	53
Interruptibles	154	168	179	190	200
Total Additional Available	304	318	329	340	350

	Design Non-Heating Season				
	83-84	84-85	85-86	86-87	87-88
Requirements					
Design Firm Sendout	963	957	950	943	936
Normal Firm Sendout	933	927	920	914	906
Excess Required	30	30	30	29	30
Resources					
Tennessee G-6	578	584	591	597	605
Stored LNG	15	15	15	15	15
Stored Propane	11	11	11	11	11
Interruptibles	119	119	119	119	119
Total Additional Available	723	729	736	742	750

Source: Supplement Tables G-1 through G-5; Response to Information Request No. 12.

During the 1981-82, 1982-83, and 1983-84 heating seasons, Holyoke received 184 MMcf, 135 MMcf, and 137 MMcf by displacement. As stated earlier, Holyoke has two interconnections with Bay State allowing the receipt of gas through one in the event of a mechanical problem at the other interconnection. Additionally, as discussed infra, Holyoke states that in the event no gas is received by displacement during a cold snap, stored and trucked supplemental supplies would be sufficient to meet requirements. In light of the successful history of displacement delivery and Holyoke's contingency planning, the Siting Council finds that reliance on these deliveries on a seasonal basis is reasonable.

Holyoke must be prepared to meet sendout requirements on a peak day and in the event of a cold snap or a prolonged period at near design conditions. Holyoke projects that its peak day requirements will decline from 12.5 MMcf in the 1983-84 heating season to 12.1 MMcf in the 1987-88 heating season. These projections are significantly lower than the peak day requirements in the range of 14.3 to 14.8 MMcf projected in the last filing. Holyoke attributes the lower projections to the switching of firm high-volume customers to an interruptible basis. Holyoke clearly has the ability to meet these peak day sendout requirements. Without receiving Bay State gas by displacement, Holyoke still can produce 2.4 MMcf of propane-air and vaporize up to 12 MMcf per day of LNG in addition to receiving 7.8 MMcf of G-6 pipeline gas from Tennessee.

In regard to its cold snap requirements, Holyoke states that it plans to maintain a 50 percent storage level of propane (approximately 11 MMcf)[7] and a 70 percent storage level of LNG (approximately 15 MMcf)

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7. See Supplement Tables G-22 indicating a constant propane storage of 11 MMcf; Response to Information Request No. 1.

throughout the heating season. In order to maintain peak day sendout levels, (12.1 to 12.5 MMcf), Holyoke would be required to vaporize approximately 4.3 to 4.7 MMcf of propane and LNG, assuming no gas is delivered by displacement. Given the stored supplementals at the planned levels, Holyoke could send out 4.7 MMcf of propane-air or LNG for more than five consecutive peak days.

Maintenance of these storage levels of supplemental supplies, is essential to Holyoke's ability to meet cold snap requirements.[8] Holyoke can maintain a design sendout of 2.4 MMcf per day of propane by receiving three truckloads per day without diminishing storage. Holyoke's propane contracts do not contain limitations on the daily delivery quantities. The Bay State contract, however, limits Holyoke to one truckload (approximately .85 MMcf) per day of LNG or one truckload of propane. Assuming daily replenishment of propane, an LNG storage level of 70 percent, and receipt of one truck of LNG per day Holyoke could sustain a sendout level of vaporized LNG of 1.9 to 2.3 MMcf per day for ten to fourteen days. Thus, the Siting Council is assured that Holyoke can meet its cold snap requirements with its present facilities subject to the maintenance of its storage inventories at the stated levels and the availability of propane and trucking. The Siting Council notes that any buildup of the MDQ would reduce Holyoke's reliance on supplementals. The Siting Council encourages Holyoke's efforts in this regard.

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8. Holyoke states that, assuming receipt of no gas via displacement, five truckloads of LNG would be required to maintain storage at the 70 percent level. Holyoke also states that the "minimum amount that the Department could survive [on] and reduce our inventory level below the 70% figure would be three trucks per day." Response to Information Request No. 4.

VI. Decision and Order

The Siting Council hereby APPROVES the 1983 Supplement to the Long-Range Forecast of Gas Requirements and Resources of the City of Holyoke Gas and Electric Department without conditions. The next Supplement shall be due on December 3, 1984.

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

Unanimously APPROVED by the Energy Facilities Siting Council on October 24, 1984 by those members and designees present and voting: Sharon M. Pollard, (Chairperson); Joellen D'Esti (for Secretary Evelyn F. Murphy); Sarah Wald (for Secretary Paula W. Gold); Stephen Roop (for Secretary James S. Hoyte); Robert W. Gillette (Public Environmental Member); Joseph W. Joyce (Public Labor Member). Ineligible to vote: Edward H. Collagan, Jr. (Public Oil Member).

30 October 1984
Date

Sharon M. Pollard
Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Essex County Gas Company for Approval of the Second Supplement to the Second Long-Range Forecast of Gas Resources and Requirements	)	EFSC 83-15

FINAL DECISION

Lawrence W. Plitch, Esq.
Hearing Officer

On the Decision:

Karen Grubb
Economist

TABLE OF CONTENTS

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 ("Forecast") of the Essex County Gas Company ("Essex" or "the Company").[1]

The Company is engaged in the distribution and retail sale of gas in northeastern Massachusetts, including the communities of Amesbury, Haverhill, Ipswich and Newburyport. The Company serves approximately 30,000 customers, of which the vast majority, over 90%, are residential.

The Company filed the Second Supplement to its Second Long-Range Forecast on August 1, 1983. Copies of the publication were distributed to five public libraries in accordance with Rule 3.4 of the EFSC Rules and Regulations. Notice of public hearing and adjudicatory proceedings appeared in newspapers of general circulation within the service area of the Company.

The first set of Staff Information Requests was sent to the Company on November 15, 1983, and the Council received written responses and supporting documentation within two weeks. A follow-up Technical Session was held at the Company's headquarters in Amesbury on December 8, 1983. On May 2, 1984 the Council staff mailed a second set of Staff Information Requests which were received on May 11, 1984. On May 18, 1984, the Council received a Late Filed Petition to Intervene from the Distrigas of Massachusetts Corporation ("DOMAC"). The Petition was denied by the Hearings Officer in the case on July 12, 1984. (See Procedural Order, EFSC No. 83-15.)

II. PREVIOUS CONDITION

The Council's previous Decision regarding the Company[2] ordered Essex, in its next Supplement, to address the anticipated effects of natural gas decontrol on its forecast of sendout. The Company stated, based on its review of the cost of home heating oil relative to gas and correspondence with its pipeline supplier Tennessee Gas Pipeline Company ("TGP"), that "gas pricing will stabilize or decrease in Massachusetts so that the price of natural gas to the end user will at least be at parity with home heating oil."[3]

Essex's sendout projections reflect the expectation that TGP will maintain city-gate prices at a level that will allow distributors to stay competitive in the residential heating market. Therefore, the Company projects that the number of residential customers with gas heat will increase as Essex adds new customers and existing nonheating customers convert to gas heat (Section III.A.1 <u>infra</u>). The Council is satisfied that the Company has complied with the Condition.

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1 Previously named the Haverhill Gas Company.

2 9 DOMSC at 207 (1983).

3 Response to Information Request SO-6 dated November 23, 1983; Forecast at 3.

III. SENDOUT METHODOLOGY

A. Normal Year Sendout

Essex forecasts sendout for three categories of firm customer: residential with gas heat; residential without gas heat; and commercial/industrial ("C/I"). Projected changes in number of customers and sendout projections are calculated separately for each customer class.

Residential heating customers compose the largest class, both in terms of total sendout requirements and number of customers served. The second largest customer class is a composite of commercial and industrial establishments. This is the class for which Essex is projecting the highest rate of growth during the forecast period. Table 1 compares forecast sendout by class during 1983-84 and 1987-88.

Essex forecasts total load as the sum of base use and heat use for each customer class. Base use is calculated as the product of the number of customers and nontemperature-sensitive use per customer (the "base factor"). Heat use is calculated as the product of the number of customers, number of degree days, and heat sensitive use per customer per degree day (the "heat factor").

1. Customer Projections

i. Residential Customers

The number of residential heating customers is projected to increase from approximately 19,800 in 1983-84 to 21,500 by 1987-88, an increase of approximately 2% per annum. The number of residential non-heating customers is projected to decrease from approximately 7,500 in 1983-84 to 7,100 by 1987-88, a decrease of approximately 1.3% per annum.

ii. Commercial/Industrial Customers

Essex projects that the number of C/I customers will increase from approximately 2,600 in 1983-84 to 3,100 by 1987-88, a rate of about 4.5% per year. The Company bases this projection on the considerable new development that it has seen in its service territory during the last five years. This trend is expected to continue and to be reinforced by economic recovery, although the Company does not support its expectations with regional or macro-economic data. Instead, it forecasts the number of large C/I customers based on personal contacts with individual customers, and forecasts the number of small C/I customers by projecting historic trends into the future.[4] In addition, the Company's linkage of its service territory's development and its C/I customer growth projections apparently assumes that Essex will be able to sell gas to these new customers at a competitive price. (See Section II, supra.)

The Council questions whether the use of survey techniques for large customers and simple trending for small customers are reliable methods for forecasting growth, especially during the later years of the forecast period. Indeed, the Company's forecasted growth may require

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4 Response to Information Request SO-4-5 dated November 23, 1983; Forecast at 7-8.

TABLE 1
FORECAST OF SENDOUT BY CLASS (MMCF)
Normal Year

Customer Class	1983-84 Nonheating Season	1983-84 Heating Season	1987-88 Nonheating Season	1987-88 Heating Season
Residential Heating	730	1625	727	1649
Residential Nonheating	106	111	99	111
Commercial/Industrial	501	1020	712	1487
Co. Use & Unaccounted For	89	177	58	206
Total Firm Sendout	1426	2933	1596	3453
Interruptible Sendout	218	27	177	-
Total Sendout	1644	2960	1773	3453

that Essex take on new long-term supply commitments in order to meet its additional requirements. (See Section V.B. and Tables 1 and 5, infra.) Under these circumstances, the Council would expect more detail and sophistication in the Company's assessment of its C/I markets than has been provided in this filing.

Disaggregation of new C/I customers by end-use or SIC code, correlation of Company forecasts with forecasts of other entities in its service territory, and analysis of regional or macro-economic data are all methods that the Company might use to augment its survey and trending techniques. The Council encourages the Company to reexamine its current projection methods in light of changes in the gas industry, and to present more detailed support for its C/I projections in its next filing.

2. Customer Use Factors

Essex disaggregates total demand into base and heat components for each customer class. The Company tracks base and heat factors (defined in Section III.A.1, supra) from monthly billing records and then makes projections about the forecast period based on observable trends.

i. Residential Heating Customers

The Company expects the base factor to decline from .0855 MCF/customer/day in 1984 to .0790 MCF/customer/day by 1988 due to improved appliance efficiency and conservation. This decline is expected to bottom out by 1988 "unless some extraordinary changes take place in gas technologies."[5]

5 Forecast at 6.

The heat factor is expected to decline from .0131 MCF/customer/ degree day in 1984 to .0124 MCF/customer/degree day by 1988 due to more efficient construction, improved insulation and heating equipment, continued use of supplemental fuels and conservation. Heat factors, which are calculated separately for each month, are the highest December through February and approach zero in July and August.[6]

ii. Residential Nonheating Customers

The Company expects the base factor to decline from .0495 MCF/customer/day in 1984 to .0484 MCF/customer/day by 1988 due to penetration of more efficient appliances, increases in the number of individually metered apartments, and conversion of the heavier users (e.g. those with hot water) to gas heat. Essex uses August/September billing data to calculate base factors in this customer class.

The Company projects some heat sensitive use for its nonheating customers. Heat factors are expected to increase from .00128 MCF/customer/degree day in 1984 to .00139 MCF/customer/degree day by 1988, which reflects a continuaton of past trends. Most heat use for this type of customer is "distress heating", which occurs when "the apartment dweller turns on the stove oven, opens the oven door and proceeds to eliminate the morning chill."[7]

iii. Commercial/Industrial Customers

Essex expects the base factor for the class as a whole to increase from .58 MCF/customer/day in 1984 to .66 MCF/customer/day by 1988. This factor is rising because the service territory is expected to continue to experience an influx of somewhat larger C/I customers. In addition, some of the commercial establishments in the reference group of existing customers are multi-family residential dwellings with historically low usage. The heat factor is projected to increase from .058 MCF/customer degree day in 1984 to .074 MCF/customer/degree day by 1988.

The Company calculates usage factors for large C/I customers based on information about past trends and personal knowledge about individual customers. Usage factors are calculated for small C/I customers based on the historic trend of small C/I customers as a group.[8] At this time, the Company does not have information on C/I customers by SIC code.[9] The Council recommends that the Company investigate how disaggregation by SIC code could enhance these projections. In addition, it might be useful to compare changes in the composition of the C/I sector with corresponding changes in the temperature sensitivity of sendout requirements. We recommend this in light of the Company's expectation that it will continue to experience an influx of larger C/I establishments into its service territory.

6 Forecast at 6.
7 Response to Information Request SO-9 dated November 23, 1983; Forecast at 5-6 and Exhibits 6-7.
8 Response to Information Request SO-10 dated November 23, 1983; Forecast at 7-8 and Exhibits 6-7.
9 Response to Information Request SO-1 dated May 11, 1984.

B. Design Year Sendout

A "design year" is the coldest year for which the Company plans to meet its firm customer requirements. Essex uses a design year of 7788 degree days, which corresponds to the coldest 12-month period experienced by Essex during the past 20 years.

The Company assumes that base use is the same in both normal and design years. Heat use, on the other hand, is greater during design years to reflect the additional requirements of colder than normal weather. The Company calculates design heat use by subtracting base use from total normal sendout. The result is multiplied by either 1.10 or 1.19 to reflect the observation that the Company's design year contains approximately a 10% greater number of degree days than its normal year heating season and a 19% greater number of degree days during its normal year nonheating season. Heat use is defined as the product of the number of degree days, the number of customers, and a heat factor. Multiplying total heat use by 1.10 or 1.19 has the same effect as multiplying the number of degree days in the equation by these numbers, which assumes that the heat factor does not change.

The Council has seen evidence,[10] however, that normal consumption behavior changes during peak weather conditions; that less conservation occurs. If this turns out to be true for Essex, it may be appropriate to use higher than normal heat factors during a design year. The Company contends that the capacity of residential and commercial furnaces makes it impossible to maintain desired indoor temperatures during severe weather. If true, this imposes limits on peak consumption behavior and makes the Company's methodology appropriate.

The Council recognizes that consumer usage patterns can be difficult to predict under design conditions. Therefore, we strongly recommend that the Company further investigate customer conservation behavior on-peak and, if necessary, adjust its methodology to reflect new evidence. In particular, we feel that it would be useful for Essex to monitor daily sendout patterns during the next heating season, concentrating on irregularities in the heating factor. In addition, we urge the Company to keep abreast of any literature concerning on-peak conservation. If Essex chooses not to depart from its present methodology, we recommend that, in its next filing, the Company discuss why its methodology is appropriate and how it enhances the reliability of its design sendout projections.

C. Peak Day Sendout

A peak day is defined as the coldest day that is likely to occur during the forecast period. The Company uses 77 degree days, the degree day total for the coldest day actually experienced during the past 20 years. Base use on a peak day is equivalent to January base use. Heat use is calculated using January heat factors.

10 9 DOMSC at 16-19 (1983).

The Company's peak day methodology seems to discount the fact that a peak day is colder than an ordinary January day. The Council questions whether it would be more appropriate for the Company to use a higher heat factor that might more adequately reflect the concerns that were expressed in Section III.B., supra. Therefore, we recommend that the Company investigate customer on-peak conservation behavior in the context of a peak day well as a design year. The Council is otherwise satisfied with the Company's peak day forecast of sendout requirements.

IV. SUPPLY CONTRACTS

A. Pipeline Gas

Essex is a customer of Tennessee Gas Pipeline Co. ("TGP") from which it receives an annual volumetric limitation ("AVL") of 4100 MMCF and a maximum daily quantity ("MDQ") of 15 MMCF. The Company is requesting an increase of 1.3 MMCF in its MDQ in 1985 and 1.2 MMCF in 1986, for a total increase of 2.5 MMCF by 1986. These increases, which can be taken at 100% load factor, translate into AVL increases of 475 MMCF and 913 MMCF, respectively. Essex expects TGP to apply to the Federal Energy Regulatory Commission ("FERC") for these increases in the near future.[11] TGP gas is supplied to Essex under the CD-6 rate schedule.

The Company has two 350 MMCF per year long-term storage contracts, one with Consolidated Gas Supply and the other with National Fuel (Penn-York). TGP provides firm transportation service of 4 MMCF per day between the storage facilities and Essex's interconnection point under the SST-NE rate schedule. According to a contract amendment, firm TGP transportation from Essex's Penn-York storage facility will be increased by 1.5 MMCF per day starting in November 1987. In addition, 2.4 MMCF per day best efforts transportation service is available from TGP.[12]

The Company has signed an agreement with TGP to purchase Canadian gas during Phase 2 of the Boundary Gas Project ("Boundary") due to commence in November 1987. Essex will be entitled to 548 MMCF annually and 3 MMCF on any given day. The Company does not believe that any improvements to its system will be necessary to accomodate Boundary gas.[13] In addition, Essex is continuing to investigate other TGP sources of pipeline gas and Sable Island gas.

B. Liquefied Natural Gas (LNG)

LNG is viewed by the Company as a peak shaving resource. It is a "supplemental gas supply not a base load supply."[14] It is the Company's standard operating procedure to begin each heating season with its 400 MMCF LNG storage tank in Haverhill filled to capacity.

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11 Response to Information Request S-10 dated May 11, 1984.

12 Response to Information Requests SO-4: Interruptible Storage Service Transportation Contract and S-10 dated May 11, 1984.

13 Response to Information Request S-1 dated November 23, 1983.

14 Response to Information Request Introduction dated May 11, 1984.

Essex has a contract to purchase 290 MMCF of LNG annually from Distrigas of Massachusetts ("DOMAC"). During the winter months Essex receives its entitlements of DOMAC LNG through the TGP pipeline via displacement with Boston Gas. The rest of the year Essex transports the LNG by truck to its storage facility.

Essex has an agreement with DOMAC, which is awaiting approval by the Economic Regulatory Administration ("ERA") and FERC, for an additional 60 MMCF annually to commence in April 1985.[15] The Company contends that "these quantities will be needed to serve firm customers," and furthermore that they must "be in place by 1986 in order to handle design weather."[16]

In addition to DOMAC, Essex has an LNG contract with Bay State Gas for firm delivery of 80 MMCF/year, with an option to buy an additional 10 MMCF/ year.[17] Bay State LNG is transported by truck directly to Essex's LNG storage tank. This contract is due to expire in January 1988.

C. Propane

The Company continues to obtain propane volumes from suppliers such as C.M. Dining Inc., Petrolane Co., and Pyrofax Gas Corp. These contracts are renewed on an annual basis. The Company exercises flexibility in its propane contracts and finds that additional supply is available on short notice. For example, the Company's contract with C.M. Dining is 25% take-or-pay and allows Essex to receive up to 200,000 gallons per day (one-third of the annual contract quantity) within 30 days. Essex has propane storage capacity of 41 MMCF at its Haverhill plant and can liquify and dispatch 7 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 during normal and design years, peak days, and cold snaps throughout the forecast period.

A. Normal Year

Tables 2 and 3 summarize the normal year resources and requirements that Essex provided in Table G-22 of the Forecast. It assumes that Boundary gas will be received as of the 1986-87 heating season. Volumes under contract in the Company's precedent agreements for DOMAC LNG and TGP gas, on the other hand, were not included in either Table G-22 of the Forecast or Tables 2 and 3, *infra*. Because sendout is projected to increase and current AVLs are still in effect, Essex requires increasing quantities of gas from underground storage to meet its normal firm sendout requirements each year. Nonetheless, Essex projects sufficient resources to meet its sendout requirements for normal years throughout the forecast period.

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15 Response to Information Requests S-3 dated November 23, 1983 and S-1 Schedule C dated May 11, 1984.

16 Response to Information Request S-1 dated May 11, 1984.

17 Forecast at Table G-24.

B. Design Year

Should design conditions develop in a given year, the Company's supply planning strategy requires several changes. Essex' options in a design year include dispatching additional gas from underground and LNG storage, purchasing extra supplies of propane, exercising its option for additional LNG from Bay State, and diverting supplies from interruptible customers. However, the Company is so dependent on new supply source contingencies that the total resources, even with the above-noted options, may not be sufficient to meet the design year needs of its customers by as early as November 1985. Tables 4 and 5 detail the scope of this problem.

As was discussed in Section IV, A and B supra, the Company has entered into several new gas supply arrangements. These include: an increase in its ACQ of LNG from DOMAC by 60 MMCF per year, beginning in April 1985; an increase in its AVL of TGP by 475 MMCF, beginning in November 1985, and by an additional 438 MMCF in November 1986; an increase in the amount of firm storage return service it receives from TGP each heating season by 227 MMCF (an additional 1.5 MMCF per day) in November 1987; and the addition of 548 MMCF per year (3 MMCF per day) in November 1987 as a result of Phase 2 of the Boundary Gas Project. Each of these four supply contingencies require the approval of the FERC. The DOMAC and Boundary agreements also require ERA authorization.

A review of Table 5 reveals that without these supply contingencies, Essex will have a design heating season deficiency (requirements in excess of resources) of 55 MMCF in 1985-86. This deficiency grows to 339 MMCF in 1986-87 and to 319 MMCF in 1987-88.

While it is apparent that the Company is aggressively pursuing new supply sources,[18] the Council is extremely concerned about the gas needs of the Company's customers should the requisite federal approvals not be timely obtained. Moreover, the Company forecasts normal year load growth of 678 MMCF (see Table 1), in its C/I class over the forecast period. The Council notes that deferral or delay of this load growth could eliminate the Company's entire design year deficiency by 1987-88. Therefore, the Council ORDERS the Company to explain in its next filing how it plans to meet its design year sendout requirements in the event that the approvals for the noted new supply sources are either delayed beyond their scheduled acquisition dates or disapproved.[19]

Specifically, the Council ORDERS the Company to provide a full explanation of its policy of adding load in advance of its assurance of

18 The Company is also involved in efforts to obtain Sable Island gas and TGP gas beyond those noted in the text.

19 Essex may want to consider arranging to further increase its DOMAC ACQ. If possible, the Council also suggests that Essex investigate doing so in a way that also enables Boston Gas to decrease its DOMAC ACQ. As noted in the Council's recent Boston Gas Company Decision (EFSC No. 83-25, March 5, 1984): "Boston Gas retains an unsatisfied request with DOMAC to further reduce its ACQ to 8400 MMCF" (10 DOMSC 278, 312 (1984)).

TABLE 2
COMPARISON OF RESOURCES AND REQUIREMENTS (MMCF)
Normal Year - Nonheating Season

REQUIREMENTS	1983-84	1984-85	1985-86	1986-87	1987-88
Normal Firm Sendout	1426	1425	1483	1545	1596
TGP Underground Storage Refill	454	393	564	551	641
LNG Storage Refill	179	195	253	252	253
Interruptible Sendout	218	271	28	0	177
Total Requirements	2277	2284	2328	2348	2667
RESOURCES					
TGP-CD6	2007	2026	1989	1989	1989
TGP Underground Storage	4	15	16	26	47
Boundary	0	0	0	0	321
LNG from Storage	87	48	70	81	57
LNG Delivery	179	195	253	252	253
Total Resources	2277	2284	2328	2348	2667

TABLE 3
COMPARISON OF RESOURCES AND REQUIREMENTS (MMCF)
Normal Year - Heating Season

REQUIREMENTS	1983-84	1984-85	1985-86	1986-87	1987-88
Normal Firm Sendout	2933	3066	3180	3316	3453
TGP Underground Storage Refill	6	1	0	15	15
LNG Storage Refill	102	92	125	125	125
Interruptible Sendout	27	23	10	0	0
Total Requirements	3068	3182	3315	3456	3593
RESOURCES					
TGP-CD6	2111	2111	2111	2111	2111
TGP Underground Storage	439	503	528	597	639
Boundary	0	0	0	227	227
Propane	40	40	40	40	40
LNG	194	184	217	217	217
LNG from Storage	284	344	419	264	359
Total Resources	3068	3182	3315	3456	3593

TABLE 4
COMPARISON OF RESOURCES AND REQUIREMENTS (MMCF)
Design Year - Nonheating Season

REQUIREMENTS	1983-84	1984-85	1985-86	1986-87	1987-88
Design Firm Sendout	1532	1530	1596	1665	1721
Normal Firm Sendout	1426	1425	1483	1545	1596
Excess of Design Over Normal	106	105	113	120	125
Maximum Storage Refill	250	267	143	163	106
Add. Requirements	356	372	256	283	231
Boundary contingency	-	-	-	-	321
Total	356	372	256	283	552
RESOURCES					
Interr. & Resale	218	271	28	0	0
Precedent agreements					
.Add. TGP gas	-	-	277	533	533
.Add. DOMAC LNG	-	-	-	22	22
Spot Purchases	138	101	-	-	-
Total	356	372	305	555	555

TABLE 5
COMPARISON OF RESOURCES AND REQUIREMENTS (MMCF)
Design Year - Heating Season

REQUIREMENTS	1983-84	1984-85	1985-86	1986-87	1987-88
Design Firm Sendout	3153	3301	3422	3568	3716
Normal Firm Sendout	2933	3066	3180	3316	3453
Excess of Design Over Normal	220	235	242	252	263
Boundary	-	-	-	227	227
Total	220	235	242	479	490
RESOURCES					
TGP Underground Storage	165	101	76	7	76
Propane from Storage	42	42	42	42	42
LNG from Storage	265	160	49	81	43
Interruptible Sendout	27	23	10	0	0
LNG Option from Bay State	10	10	10	10	10
Firm Resources	509	336	187	140	171
Precedent agreements					
.Boundary	-	-	-	227	227
.Add. TGP gas	-	-	198	380	380
.Add. DOMAC LNG	-	-	38	38	38
Total	509	336	423	785	816

new supplies. Moreover, the Council ORDERS the Company, in its next filing, to present a supply plan that is sufficient to meet its forecasted sendout requirements. The Company shall adjust its forecast of load growth, present a plan to meet requirements through a conservation and load management program, or take other steps that it sees as appropriate to comply with this Condition. The Company shall be prepared to justify that its supply plan will provide its customers with reliable service at minimal environmental impact and the lowest possible cost.

C. Peak Day

A gas utility must have sufficient sendout capacity to meet its system's peak day needs. While total supply is dependent upon the aggregate volumes of gas available over a season or year, peak day sendout is a function of the maximum rate of firm deliveries in a single day. Table 6, which summarizes the Company's peak day resources and requirements, illustrates the importance of LNG in the Company's peak day resource portfolio. LNG cannot be completely replaced by other sources such as pipeline gas.

One potential problem that was identified by Essex in Table G-14 of the Forecast concerns one of the Company's two vaporizers at the LNG plant in Haverhill. Due to obsolescence, Essex expects there to "be a need to replace one of the vaporizers in 1985." The Table also indicates that the older vaporizer will probably be kept on as a backup. The Council requests that the Company include an update on the status of this situation in its next filing.

The Company indicates that its LNG plant has a maximum daily design capacity of 20 MMCF. In addition, Essex obtains 1 MMCF per day in peak day LNG capacity through a displacement arrangement with Boston Gas and TGP. Although this arrangement is not contractually firm on peak, historically the Company has experienced no problems with obtaining this LNG when needed.

The Council is satisfied that the Company will maintain an adequate margin between peak day capability and requirements throughout the forecast period.

D. Cold Snap

A "cold snap" is defined as a prolonged series of days at or near peak conditions, such as the two-to-three week period experienced in Massachusetts during the 1980-81 heating season. To meet cold snap requirements the Company must demonstrate that the aggregate resources available to it are adequate and that it can sustain the capacity to deliver large daily loads.

TABLE 6
COMPARISON OF RESOURCES AND REQUIREMENTS (MMCF)
PEAK DAY

	1984-85	1985-86	1986-87	1987-88
PEAK DAY SENDOUT REQUIREMENT	41	42	44	46
Peak Day Resources				
TGP-CD	15	15	15	15
TGP from Storage (firm transportation)	4	4	4	6
LPA	7	7	7	7
LNG Displacement	1	1	1	1
LNG from Storage	20	20	20	20
Boundary gas	-	-	2	2
Total firm peak day resources	47	47	49	51
TGP from Storage (best efforts transportation)	2	2	2	-
TGP-Precedent Agreement	-	1	2	2
Total peak day resources	49	50	53	53

The Company can best handle a cold spell early in a heating season when inventories are high. During the 1984-85 heating season, Essex can meet sendout requirements for 3 consecutive weeks at peak day levels when storage is full, but only for 11 days when it is half-full. The Company can withstand 7 consecutive weeks of 60 degree day weather when inventories are full, and one month when they are half-full. This analysis does not include the impact of additional quantities of gas that are awaiting consideration by the ERA and FERC. If approved, the increase in MDQs of pipeline gas will augment the Company's resources for meeting cold snap requirements.

Essex begins each heating season with its 400 MMCF storage tank filled to capacity. The Company states that this procedure "minimize[s] the impact of an unforeseen delay or cancellation of a DOMAC shipment."[20] Essex receives from DOMAC approximately 21 MMCF per ship, so the impact of one delayed or cancelled ship would be small in relation to overall capacity. During the heating season Essex expects to recieve 145 MMCF from DOMAC via displacement.

The Council finds that it is essential for Essex to maintain adequate reserves of LNG to ensure reliability. Increasing LNG purchases will help Essex to maintain storage levels to meet design requirements. Moreover, the Company's large LNG storage capacity (larger than its DOMAC ACQ) insulates it somewhat from reliance on individual DOMAC shipments.[21] The LNG purchase, in and of itself, does not substantially change Essex's exposure to supply disruptions during a cold snap, and will partially alleviate the Company's long term need for supplies.

20 Response to Information Request S-3 dated May 11, 1984.

21 In this respect, Essex differs from Boston Gas. See 10 DOMSC 278, 337-340 (1984).

VI. DECISION AND ORDER

The Council hereby APPROVES the Essex County Gas Company's Second Supplement to the Second Long-Range Forecast of Gas Resources and Requirements subject to the following Conditions:

(1) In its next filing, the Company shall explain how design sendout requirements will be met beginning in the winter of 1985-86, as per Section V.B., *supra*.

Energy Facilities Siting Council

Lawrence W. Plitch (JGW/fr)

By Lawrence W. Plitch, Esquire
Hearings Officer

On the Decision:
Karen Grubb
Staff Economist

Unanimously APPROVED by the Energy Facilities Siting Council on October 24, 1984 by those members and designees present and voting: Sharon M. Pollard, Chairperson; Joellen D'Esti (for Secretary Evelyn F. Murphy); Sarah Wald (for Secretary Paula W. Gold); Stephen Roop (for Secretary James S. Hoyte); Robert W. Gillette (Public Environmental Member); Joseph W. Joyce (Public Labor Member). Ineligible to vote: Edward H. Collagan, Jr. (Public Oil Member).

30 October 1984
Date

Sharon M. Pollard

Sharon M. Pollard
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition for Approval of the Wakefield Municipal Light Department's Third Supplement to its Second Long-Range Forecast of Gas Requirements and Resources	)	Docket No. 84-2

FINAL DECISION

James G. White, Jr.
Hearing Officer

On the Decision:

John C. Dalton
Staff Analyst

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

I. INTRODUCTION

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

II. SUMMARY OF THE PROCEEDINGS

Pursuant to the provisions of Mass. Gen. Laws Ann. ch. 164, sec. 69I, the Department filed the Third Supplement to its Second Long-Range Forecast with the Council on June 28, 1984. On July 3, 1984, the Department was ordered to publish the Notice of the Adjudicatory Proceeding. Rule 13.2. No persons filed petitions to intervene or otherwise participate in the proceeding. The Department responded to one set of Information Requests issued by the Council Staff.

III. ANALYSIS OF THE SUPPLEMENT

A. Standard of Review

The Council uses three criteria to ensure that the methodologies used in forecasts are reasonable. Rules 69.2 and 66.5 All companies under the Council's jurisdiction, must use a reviewable forecast methodology that is appropriate to the particular system and that is reliable in its ability to forecast future gas requirements and sendout. Given Wakefield's size and position as an all-requirements customers of Boston Gas, the Council has previously determined that Wakefield need only file a simple "narrative" forecast supplement which focuses on the demand side of the forecast. In Re Wakefield Municipal Light Department, 4 DOMSC 198 (1979).

In its current forecast, Wakefield has again submitted a "narrative" filing and provided tables projecting sendout requirements for all four customer classes for each year of the forecast period. Wakefield used the same methodology approved by the Council in its Decision on the Department's Second Supplement In Re Wakefield Municipal Light Department, 10 DOMSC 146 (1984).

B. FORECAST METHODOLOGY

1. Description of Forecast Methodology

Wakefield's forecast methodology for each customer class is based on determining the average annual use per customer for the previous year and applying a conservation adjustment. The adjusted customer use factor is multiplied by the projected number of customers, resulting in an annual use estimate for the customer class. The methodology is basically the same for space heating customers, except that the average use per customer is broken down into heating and non heating use per customer, and the heating use is normalized.

2. Analysis of Forecast Methodology

Boston Gas's 1983 Forecast Supplement provides a forecast of normal year sendout figures for Wakefield which is useful for evaluating the reliablity of Wakefield's forecast methodology. See Boston Gas Company, Docket No. 83-25, Supplement Table G-3(c). Table I compares Boston Gas's figures to those provided by Wakefield in its Table "Form 7" in its 1984 Supplement.

Table I
Projected Gas Sendout (MCF)

	1984/85	1985/86	1986/87	1987/88	1988/89
Contract Limits	390,178	409,687	430,171	451,680	474,264
Wakefield's Design Year Forecast	357,201.4	356,778.7	356,313.3	355,761.4	355,201.9
Wakefield's Normal Year Forecast	339,700.5	339,247.3	338,740.2	338,179.6	337,567.8
Boston Gas's Forecast for Normal Sendout	351,300	362,800	374,300	385,600	--------

As indicated in Table I, Boston Gas's forecast of normal year sendout exceeds Wakefield's forecast of design year sendout in 1985/86 through 1987/88. Wakefield's design year figures indicate a .11 percent negative annual average compound growth rate. This compares to a .13 percent negative annual average compound growth rate for Wakefield's projected normal year sendout. Boston Gas projected a 2.4 percent compound growth rate in normal sendout.

Boston Gas's forecast of Wakefield's normal year sendout for 1983-84 proved to be more accurate, only .1% less than the normalized actual sendout; whereas Wakefield's 1983-84 projection overstated the normalized actual sendout by 1.2%. Boston Gas's greater forecast precision most likely reflects its more sophisticated degree-day sensitivity correction. For the forecast period, however, the different assumptions used by Wakefield and Boston Gas account for the discrepancy between their forecasts. 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, since Boston Gas assumes that no new customers previously had any gas service. Wakefield assumes that 80% of its new heating customers previously used gas for non-heating purposes. Second, Boston Gas does not assume any conservation; Wakefield assumes a 1.5% conservation rate. The Siting Council does not find these discrepancies to be serious because they only reflect different assumptions and do not have implications for the reliability of Wakefield's supply. See Section III. C., infra.

Based on the comparison of Boston Gas's and Wakefield's Forecasts and on the Department's 1983/84 forecast record, the Council finds the Department's methodology to be reliable and appropriate for a gas company of Wakefield's size, paticularly given Wakefield's position as a total requirements customer of Boston Gas.

3. Peak Day

As a Condition of its approval of the Department's 1982 Supplement, the Council required Wakefield to provide a forecast of peak day use for each year of the forecast period. Table II lists Wakefield's computations. The Department indicates that accurate calculations of peak day usage would become available with the installation of a Supervisory Control and Data Aquiring (SCADA) System. Wakefield projects that it will put out a request for proposals for a SCADA system by early 1985. Installation and activation of the system's daily gas reading tracking function depends on "the delivery date quoted by the successful bidder." Response to Information Request No. 2.

Table II

DESIGN YEAR PEAK DAY

YEAR	HEATING (MCF)	NON-HEATING (MCF)	TOTAL (MCF)
1984/85	2,289.2	436.0	2,725.2
1985/86	2,294.1	433.7	2,727.8
1986/87	2,298.5	431.4	2,729.9
1987/88	2,302.2	429.0	2,731.2
1988/89	2,305.4	428.7	2,732.1

In the meantime, the Department has chosen to provide the Council with estimated peak day consumption figures based on the daily heating and non-heating loads of the 1983/84 reporting period and on the 60 degree day which occurred on December 12, 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 sendout forecast, the Council finds Wakefield's methodology and the resultant figures to be sufficiently reliable estimates. To ensure that this reliability is maintained in future forecasts, the Council requests Wakefield to continue to forecast peak day use for each year of the forecast period based on estimated peak day consumption. When the SCADA system's tracking function is operating, metered data should be used in place of estimated data.

C. Supply: The Boston Gas Contract

Wakefield purchases its total gas supply, a firm supply of gas from Boston Gas. Under the contract, Wakefield is allowed to increase its annual purchases from Boston Gas by five percent, on a normalized basis, over the actual purchases made in the preceeding year. If the Department exceeds its annual contract amount, it may be subject to a penalty based on the contracts "unauthorized overrun" clause.[1] For contract year 1983-84, the Department's actual take of 336,750 fell well within its contract limit of 364,652 Mcf. Forecast at 1. As Table I indicates, this contract limit is not projected to constrain Wakefield's gas purchases. The Council is not concerned by the fact that Boston Gas's projected sendout figures for Wakefield are more conservative than Wakefield's because these projections have no direct bearing on the volumes allowed Wakefield under the contract. The Council notes, however, that the use of higher sendout figures for Wakefield by Boston Gas reduces the likelihood of a supply shortfall to the extent Boston Gas uses the higher figures in securing supplies. The discrepancy between Wakefield's design year forecast and its contract limits is not of concern, because Wakefield's contract limits are figured on a normalized basis. The Council finds that Wakefield has sufficient supplies available from Boston Gas over the forecast period to meet both normal and design year projections.

IV. Decision and Order

The Council hereby APPROVES the Third Supplement to the Second Long-Range Forecast of the Town of Wakefield Municipal Light Department without conditions. The fourth Supplement is due on July 1, 1985.

Energy Facilities Siting Council

By James G. White, Jr.
James G. White, Jr.

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

Unanimously APPROVED by the Energy Facilities Siting Council on October 24, 1984 by those members and designees present and voting: Sharon M. Pollard, (Chairperson); Joellen D'Esti (for Secretary Evelyn F. Murphy); Sarah Wald (for Secretary Paula W. Gold); Stephen Roop (for Secretary James S. Hoyte); Robert W. Gillette (Public Environmental Member); Joseph W. Joyce (Public Labor Member). Ineligible to vote: Edward H. Collagan, Jr. (Public Oil Member).

30 October 1984
Date

Sharon M. Pollard
Sharon M. Pollard
Chairperson