DECISIONS AND ORDERS

MASSACHUSETTS ENERGY FACILITIES SITING COUNCIL

VOLUME 8

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COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Boston Gas Company et. al. for the Approval of an Occasional Supplement to their Second Long-Range Forecast of Gas Needs and Requirements	)	EFSC No. 80-25A

FINAL DECISION

Paul T. Gilrain, Esq.
Hearing Officer

John P. Hughes
Chief Economist

May 24th, 1982

A. INTRODUCTION

The Energy Facilities Siting Council hereby conditionally APPROVES the Petition of the Boston Gas Company et al. ("Boston Gas" or "the Company") for the approval of an Occasional Supplement to their Second Long-Range Forecast of Gas Needs and Requirements. The background and history of the proceedings will be reviewed in part B below. Section C describes the Company's North Shore Division and the reasons for the uncertainty surrounding the availability of the Salem LNG facility. The need for replacement peak shaving capacity is discussed in section D; description of the proposed additions at Danversport in section E; alternatives to the proposed additions in part F; and environmental impacts in part G. Finally our conclusions and the Decision and Order are contained in part H.

B. BACKGROUND and HISTORY

On March 19th, Boston Gas filed a Letter of Intent indicating that they would file an Occasional Supplement to their Second Long-Range Forecast* within three weeks. On that same date, the Council's Hearing Officer delivered an Order of Notice to the Company, requiring that they publish notice of an adjudicatory proceeding in The Salem Evening News, and the Peabody Times, once a week for three consecutive weeks. In addition, the Company was ordered to post such notice in the five towns serviced by Boston Gas' North Shore Division: Salem, Beverly, Danvers, Peabody and Middleton. The Company complied in full with the Order.

In its Letter of Intent, the Company indicated that their proposal would be for the construction of certain additions to their Danversport

* The Council approved conditionally in part, and rejected in part the Company's Forecast in March (1982) 7 DOMSC __, EFSC No. 81-25 (1982).

Liquid Propane-Air ("LPA") facility. As an initial matter, the Council Staff made an informal visit to the facility on March 20th, 1982. As a result of that visit and subsequent telephone discussions with the Company, it became apparent that: 1) any environmental impact would be very local in nature, confined to Danvers; and, 2) that the facility was located within the boundaries of the Massachusetts Coastal Zone. (Mass. CZM plan, Vol. II). The Staff then took the following actions: during the week of March 22nd, the Hearings Officer personally telephoned the Town Manager of Danvers and explained the substance of the Company's proposal as well as Siting Council procedure; copies of the Notice were hand delivered to residences on the two streets near the Danversport plant, Broad and Appleton Streets; and, notice was given to the Office of the Secretary of Environmental Affairs and the Director of the Office of Coastal Zone Management ("CZM").

The Company filed its completed petition on April 2, 1982 and on April 9th, a pre-hearing conference was held at the Council offices. No interested persons or intervenors came forth. The Company was represented by John McKenna, acting President; L. William Law, General Counsel and William Luthrin, Project Manager. At the prehearing conference, the parties agreed to hold a Public Hearing at the Danvers Town Hall on April 22nd, at 7:00 P.M. and the Company was ordered to publish notice of the meeting in like manner as described above.

At the April 22nd Public Hearing, the Company was represented by Messers. Law, Lutherin and Joseph Toner, a company engineer. John Hughes, Chief Economist and Paul Gilrain, General Counsel, represented the Siting Council. The hearing was attended by over a dozen concerned citizens as well as Representative Theodore Speliotis of Danvers and

John Monahan of Beverly. Among the concerns expressed at the hearing were: the desire that the LPG trucks take a route to the facility which would avoid residential neighborhoods; the additional noise pollution which residents feared might be caused due to the increased use of the plant; and, the residents' desire that they receive some assurance that the improvements to the plant not result in its permanent usage as a primary peak shaving facility. (See: Transcript Vol. No. 1; passim.)

Following the Danvers hearing, the Council Staff began the discovery process; which eventually led to three rounds of discovery and responses. Further, on May 5, 1982, Chief Economist Hughes and Hearing Officer Gilrain visited the facility, this time formally with Company representative Joseph Toner. The Staff contingent personnally inspected the site and drove over all four of the proposed transport routes to assess the impact and safety of each. Although the Staff solicited further written comments from local residents, none were forthcoming. One final visit to the site was made by the Hearing Officer and CZM staff biologist Gary Clayton in order to better assess the projects potential impacts on the coastal zone.* The following analysis is based on the information contained in Council dockets and the record in this particular docket.

It must be emphasized that the Council's decision is based on the tripartate decision criteria as to the need for the improvements in the facility (see part D, infra.); the environmental impact of the facility (see part G, infra.) and the cost effectiveness of the chosen alternative (see part E, infra.). No one factor is overriding in such a

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* Mr. Clayton's report and analysis are appended hereto as Appendix "A".

determination yet because of the unique circumstances surrounding the Salem LNG tank (see part C, infra.), the Council's concern must necessarily be focused on the peak shaving capability of the Company's North Shore Gas system. The following analysis will expand on this.

C. The North Shore Division's Salem LNG Facility

The Salem LNG plant is Boston Gas Company's primary peak-shaving facility serving the Company's North Shore division. The plant consists of a 290,000 barrel LNG storage tank and vaporization units. The North Shore service area has 29,417 total customers from 5 towns: Salem, Peabody, Beverly, Danvers and Middleton. The division is wholly isolated from other operating divisions, having its own "city gate" take stations on the Tennessee Gas Pipeline (See Table 1). In addition to the Salem facility, the division is served by the Danversport LPA facility, which presently has less than half the peak day sendout capacity of the Salem plant. These two peak shaving facilities and the two city gate stations are the only sources of gas supply presently available to serve the North Shore Division.

On May 22, 1981, the Office of Operations and Enforcement ("OOE"), of the U.S. Department of Transportation Materials Transportation Bureau ("MTB") issued a Notice to the Boston Gas Company alleging that its Salem LNG storage tank was hazardous to life or property within the meaning of the Natural Gas Pipeline Safety Act ("NGPSA") as amended (49 U.S.C. 1679 (b)). The notice was based upon an investigation and analysis performed by MTB in conjunction with the Massachusetts Department of Public Utilities ("DPU"). An on-site inspection had taken place on October 7 and 8, 1980. Hearings on the matter commenced on July 1, 1981 and terminated November 10, 1981. The Final Order was

Table 1.

Boston Gas Company

North Shore Division - Summary Statistics

Towns	Salem, Peabody, Beverly, Danvers and Middleton
Total Division Customers[1]	29,417
Sendout Statistics:	
Division Baseload Sendout	3.74 BBtu/day
Division Heating Increment	0.47 BBtu/DD
Firm Peak Day Design Sendout	37.89 BBtu/peak day
Pipeline Gas Delivery Stations:[2]	
Danversport (Salem/Peabody)	15.0 BBtu/day
West Peabody	2.4 BBtu/day
Peak Shaving Facilities:	
Salem LNG Vaporization	15.0 BBtu/day[3]
Salem LNG Storage	1,000 BBtu
Danversport LPA Plant	6.6 BBtu/day
Danversport Propane Storage	127,500 gallons[4]

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1 The Company serves a total of 490,825 customers in 8 divisions.

2 Pipelines takes are contractual maximum daily quantities ("MDQ") from the Tennessee Gas Pipeline.

3 With full back-up units with equal capacity.

4 Equivalent to approximately 11.7 MMBtu.

Sources: Occ. Suppl.; Staff Information Requests

First, the Company was ordered to more carefully monitor the Salem tank and to propare an emergency plan to be implemented in the event of a serious leakage problem or other structural failure; and,

Second, immediately after the 1981-82 winter heating season, the tank was to be removed from service, emptied, inspected, and repaired and retested as necessary to comply with appropriate State and Federal safety regulations. (49 CFR Parts 190, 191, 192 and 193; Massachusetts State Code DPU 11725-E, Section 27B).

The Salem LNG tank has a diameter of approximately 150 feet and is approximately 136 feet high. The double-walled structure consists of an inner tank made of 9% nickel steel and an outer tank of carbon steel. Between the double walls is "perlite" insulation. The tank was built in 1972 and its lease rights were purchased by Boston Gas* from the original lessee in 1973.** Throughout the tank's operational history, evidence suggests the presence of leaks. (DOT Order of Nov. 23, 1981, Docket CPF 1036-H) These leaks, which have occured around the entire periphery of the tank, are presumed to result from a "construction oversight" in which the weld joints between the nickel steel inner tank anchor straps and the carbon steel outer tank bottom closure plates were mis-aligned when sealed. (pp. 3-4, DOT Order). As a result of these inadequate weld connections, the carbon steel outerwalls may be subject to temperatures below their rated design levels. Low temperatures can induce brittleness, resulting in cracks and possible structural failure under the pressures of normal operation. (p. 5, DOT Order). Efforts to

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* Massachusetts LNG, Inc., a wholly-owned subsidiary of Boston Gas Company, leases the Salem LNG facilities.

** The original leasee was the New England Electric System.

permanently correct the problem by means of the use injected epoxy sealants were evidently unsatisfactory to OOE. Concluding that the tank's "leak history indicates that additional failures of unknown magnitude may be imminent," OOE ordered the tank's removal from service for thorough inspection and repair (p. 4, 6-8, DOT Order).

D. The Need for Replacement Peak Shaving Capacity

The DOT Order requires that the Salem tank be removed from service beginning April 1, 1982 and that any work necessary to insure the integrity of the structure be completed by October 1, 1982. However, not knowing the scope of the necessary repairs until the tank is completely emptied and inspected, the Company can offer no firm assurances that the work can be completed and the tank sufficiently filled with LNG (by truck) to meet the design year requirements of the customers in the North Shore division during the 1982-83 winter heating season. (Occ. Suppl.). Since there is no guarantee that the Salem facility can return to service at any predetermined time before or during the 1982-83 heating season, and because of the lack of otherwise sufficient redundant peak shaving capacity, it is imperative to plan for adequate contingency capacity for the coming winter. This is necessary to insure that firm peak day sendout requirements are met.* Table 2 shows the most recent estimate for design year peak shaving requirements in the North Shore division for the 1982-83 heating season. Table 3 shows the number of days in which the Company could experience a

* At risk are the abilities of thousands of customers to have space heat on the coldest days of the 1982-83 winter.

shortfall in its ability to provide supplemental gas supplies assuming the unavailability of LNG from Salem and relying solely on the existing Danversport LPA plant's capacity, again assuming design conditions.

Additionally, the Company designs its production facilities to provide adequate capacity to meet firm peak day requirements under design conditions.* Firm peak day sendout for the North Shore Division is 37,890 MMBtu, of which 20,240 MMBtu must be provided using supplemental supplies, i.e., a combination of both LNG and LPA. However, Danversport can presently deliver only 6,600 MMBtu. Without the Salem LNG facility, the Company's firm customers would experience a 13,640 MMBtu supply shortfall on design peak days. To meet this contingency, the Company is proposing to upgrade the capacity of the Danversport propane/air production facility. The proposed additions to the LPA facility at Danversport will displace LNG usage with LPA usage as the primary Supplemental gas resource for the North Shore's peak shaving requirements. But the Company has a "take-or-pay" contract for its LNG supplies (from Distrigas), and if some supplies can't be used in one division of the system, it must be used in others. Boston Gas expects to use the Mystic/Lynn and Boston/Norwood divisions, and equivalent amounts of propane which were to be used in the two Boston area division will now be transferred to the North Shore. Thus, on a system-wide basis, there will be no substantial change in the Company's forecasted resource mix, as recently approved by the Council in its adjudication of the Company's Second Long-Range of Gas Needs and Requirements.

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* There are 73 degree days in a design peak day in which the average daily temperature is - 8°F.

E. Description of the Existing Facility and Proposed Additions at Danversport

The Company's existing propane/air production facility, that is dedicated to the North Shore Division, is located at 18 Broad Street, Danversport, Massachusetts. The plant was originally built in 1951, with modifications made in 1969. The facility site utilizes approximately 5.35 acres of "Industry I" zoned land. The plant has a rated capacity of 6,600 MMBtu per day of natural gas equivalent. Vaporization is provided by two steam vaporizers, each having a capacity of 2,500 gallons of liquid propane per hour. The plant has two steam generators, one oil-fired and the other gas-fired, each capable of producing 3,450 lbs. of steam per hour. Air generation is provided by four rotary vane air compressors each rated at 480 scfm and having a discharge pressure of 100 psig. Three compressors operate off natural gas; the fourth, an electric motor. The plant has three 30,000 gallon water capacity (W.C.) and one 60,000 gallon W.C. above ground storage tanks for total liquid propane storage of 127,500 gallons (85% W.C.).* A 40' X 60' cement block structure contains the air and steam generation equipment, propane vaporizers, and the controls for the production and mixing of propane/air vapor. Also at the site are two smaller block structures which house the Salem and Beverly "city gate" stations which connect with the Tennessee Gas Pipeline. The Danvers/Salem feed system is fed from the "Salem" building and the Salem/Beverly loop is fed from the "Beverly" building. The Salem building also contains facilities for

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* Propane storage is not completely filled to full water capacity to allow for expansion of liquid due to outside temperature changes.

Table 2.

Boston Gas Company

North Shore Division - Simulated Design Year Peak Shaving Requirements

Month	Days Peak Shaving Required	Peak Shaving Volumes (MMBtu)
Nov. 1982	6	8,224
Dec. 1982	22	103,761
Jan. 1983	23	142,715
Feb. 1983	22	123,879
Mar. 1983	15	50,970
Apr. 1983	1	591
Total	89	430,140

* Design Year assumptions: 6,300 total degree days and 25 "extremely cold" days when mean temperature is 20°F or colder. A "degree day" is a measure of the deviation of the mean daily temperature from (below) 65°F.

Source: Occasional Supplement

Table 3.

Boston Gas Company

North Shore Division - Days of Insufficient Peak Shaving Capacity Capacity*

Month	No. of Days	Total Deficiency (MMBtu)
Nov. 1982	0	0
Dec. 1982	6	20,086
Jan. 1983	10	36,753
Feb. 1983	8	23,039
Mar. 1983	3	3,494
Total	27	83,372

* Assumes Salem LNG is not on line and Danversport LPA facility is on line, but without proposed improvements.

Source: Occasional Supplement

gas conditioning and final mixing of propane/air and natural gas prior to entering the two major distribution loops. The Danversport facilities interface with 389 miles of gas mains that ultimately serve approximately 30,000 customers.

To ensure that the Company will have sufficient capacity to meet both design year and design day requirements without the Salem LNG facility, for the 1982-83 winter heating season, the Company is proposing to increase the production capacity of the Danversport LPA plant from 6,600 MMBtu/day to 25,282 MMBtu/day. This would require the installation of an additional propane vaporizer, four additional air compressors, and a redesigned mixing and control system.

The Company owns a Black, Sivalls & Bryson water bath type vaporizer which is presently not in use. It has a capacity of 7,500 gallons per hour or 16,500 MMBtu/day, and can be easily installed at Danversport.

The Company proposed to add 5,200 cubic feet per minute (cfm) of air compressor capacity which would allow for a maximum production rate of 17,557 Mcf/day of propane/air mixture at a heating value of 1,440 Btu/cf with a delivery pressure into the system at a minimum of 90 psig required on a design day. This additional capacity would allow the Danversport plant to deliver a total maximum of 25,282 MMBtu/day, which is sufficient to meet the Company's design peak day sendout requirements of 20,240 MMBtu. Four 1,300 cfm diesel driven portable air compressors would be installed. Two would be permanent and two would be leased for the 1982-83 heating season, or until the Salem LNG facility returns to service.

Table 4.

Boston Gas Company

Estimated Costs of Danversport LPA Plant Additions

Description	Estimated Cost
Piping and Mechanical Work	$42,000
Electrical Work	18,000
Foundation for Pump and Vaporizer	5,000
Control Panel and Instrumentation	17,000
Field Mounted Instruments and Control Valves	15,000
Portable Air Compressors	200,000
Total Estimated Equipment and Subcontracts	$297,000
Engineering Design, Specification Bid Preparation	25,000
Construction Supervision and Startup	10,000
Total Estimated Engineering and Construction Supervision	$35,000
Total Estimated Cost	$332,000

Source: Occasional Supplement; costs are estimates as of April 2, 1982.

The Company is also proposing to replace the plant's old Askanie control system with a "state-of-the-art" electronic ratio control system. This system would "ratio" the exact amounts of propane and air to ensure that the mixture is within the interchangeability limits for natural gas, ie.e., that the mixture is neither too rich nor not rich enough. In the operation of the plant, liquid propane is pumped from storage to a vaporizer where the liquid is heated into propane vapor. At the same time, the air compressors compress atmospheric air to a pressure of approximately 100 pounds per square inch gauge (psig). The mixing and control system blends the high pressure air with the vaporized propane (approximately 57% propane and 43% air by volume), to form a mixture which has a final heating value of approximately 1,400 Btu/cf. This mixture is then injected into distribution mains where it mixes with pipeline gas.

The estimated costs for the proposed additions to the Danversport plant are shown in Table 4.

With respect to the cost estimates, two facts are noteworthy: 1) the absence of any capital charges for the vaporizer which reflects the fact that the Company already owns the equipment; and 2) two of the four portable air compressors are to be leased until the Salem facility is returned to full service which further reduces capital charges.

F. <u>Alternative Sources of Peak Shaving Capacity</u>

Alternatives to the proposed additions at Danversport are severely limited because of the North Shore Division's physical isolation from the rest of Boston Gas Company's service territory. This constrains the Company from using surplus peak shaving capacity that serve other divisions to meet estimated design day loads in the North Shore. The Company's Occasional Supplement identified five alternatives related to the use of other LNG facilities; it discussed the potential to increase pipeline deliveries into the division, via the Tennessee Gas pipeline; it considered alternative LPA facilities that are owned by the Company; and finally, it appraised the need for new peak shaving capacity in relation to Company policies with respect to interruptible sales and new heating hookups. Each of these alternatives will be briefly analyzed below.

First, several of the "alternatives" speculate about increased usage of some other Company peak shaving facility, e.g., Distrigas LNG (at Everett), Lynn LNG, Commercial Point LNG, or propane/air facilities in Gloucester, Reading and Revere. In each case, the delivery of supplemental gas from the indicated peak shaving facility is technically infeasible because there is no underground pipeline interconnection with the North Shore Division. For example, in order to feed Distrigas LNG vapor into the North Shore area in sufficient quantities to meet the estimated load, a 16" diameter underground pipeline would have to be constructed from Lynn to Salem. Lynn is the terminus of the high pressure line which feeds Distrigas LNG into the Company's Mystic/Lynn division.* This line would run approximately 5.6 miles, following a route along an existing railroad bed and also major city streets in Lynn and Salem. The estimated cost is $2.4 million, considerably more than

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* The Mystic/Lynn division is interconnected with the Company's largest division. Boston/Norwood, via 16", 20", and 24" pipelines. The Mystic/Lynn division serves 145,000 customers and the Boston/Norwood division served 292,000.

the Danversport alternative. While it could be argued that some long-term benefits might accrue from such an interconnection, in this case, there is not sufficient time to either license or build such a line to make any impact on the coming heating season's peak needs. Additionally, the Council questions the fiscal efficacy of such an expensive pipeline interconnection whose need is predicated on limited, peaking needs as opposed to year-round baseload needs. Furthermore, the laying of a pipeline to interconnect operating division is not necessarily sufficient to provide the needed gas supplies. Pressure differentials, between divisions, may require the installation of a compressor station at the point of interconnection. This would certainly be the case if attempts were made to feed additional supplemental supplies from the low pressure divisions in and around Boston (10 psig), to the higher pressure North Shore division (90 psig). (Occ. Suppl.)**

It should also be noted that without the Salem LNG facility in service, the Company will have less LNG in storage at the beginning of the 1982-83 winter season than would be the case if Salem were in service. Hence, if an attempt were made to direct DOMAC (Everett), Lynn or Commercial Point (Dorchester) LNG to the North Shore, it would result in a more rapid drawdown of these supplies, and potentially impair the Company's peak sendout capabilities in the other division.

It is clear to the Council that attempts to service the North Shore Division with LNG facilities located in other divisions would be

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* The cost of a natural gas compressor-interface between the North Shore and Boston/Norwood divisions was not estimated, and justifiably so, because the cost would have been in addition to the cost of the Lynn-to-Salem pipeline which was already excessive by a ratio of over 7-to-1.

technically infeasible given the short lead-times available before the 1982-83 heating season and also because the cost of such efforts would be certainly imprudent relative to the Danversport proposal.

Boston Gas also examined the feasibility of installing a small "pressure type" satellite LNG tank of approximately 60,000 gallons within the existing LNG impounding area at Salem and tying this tank into the existing vaporization and truck unloading system. LNG trucks would off load into the stationary satellite tank and when peak shaving was required, LNG would be withdrawn, vaporized and sent out to meet demand in the same manner that LNG is withdrawn from the existing Salem facility. However, the cost of the small tank alone is estimated to be between $450,000 to $500,000. Additionally, this alternative would require construction activity in the same area where the Salem tank repair operations are underway. For these reasons, the Council rejects this alternative. Locating a satellite facility at some other location with the North Shore division would result in additional costs because vaporization, truck handling, and an LNG impounding area, along with the storage tank, would have to be added at any other site.

A prerequisite to using off-system purchases of LNG from other utilities (e.g., Bay State Gas or COM/Gas) is the necessary facilities to inject the gas into the North Shore distribution system. Without a satellite facility as described above, this option is also infeasible.

Firm deliveries of pipeline gas to the North Shore division are provided by the Tennessee Gas Pipeline Company up to contractual maximum daily quantities ("MDQ") for each of the two stations supplying the area. (See Table 1). Tennessee is the sole pipeline supply serving the division. Tennessee has also indicated to Boston Gas that they can not provide increased firm deliveries to compensate for the withdrawal from service of Salem LNG. The Company does have agreements with Tennessee to provide "best efforts" transportation of underground storage volumes. These volumes could be used to serve demand above MDQ if they can be delivered. The Council is aware that when the needs are greatest (on extremely cold days), "best efforts" deliveries are the least probable. Hence, the Council cannot condone total reliance on this source for the 1982-83 heating season. Nonetheless, the Council believes that this source should be used to the extent that it offsets the use of more expensive propane air peak shaving supplies, and a conditions is imposed to this Decision and Order to that effect. Use of "best efforts" pipeline deliveries, however successful, does not diminish the need for the additional peak shaving capacity in the North Shore Division.

Besides the facility at Danversport, the Company owns and operates three propane air plants in Gloucester, Reading and Revere. The facilities feed into other divisions of the Company's distribution system and are not capable of assisting the North Shore division in meeting its sendout requirements, for the same reasons as discussed above with respect to LNG. Similarly, the construction of new LPA facilities at a site other than Danversport would require new storage, vaporization and related piping and controls, and greatly exceed the cost of the proposed Danversport alternative.

Finally, the Company considered the extent to which reductions in interruptible loads and new customer hook-ups might impact the need for the new facilities. Interruptible sales are not routinely allowed on peak days and thus so not alleviate in any way the need for additional peak shaving capacity. The Company already classifies the North Shore division as a "saturated area" in terms of potential new hookups. In any event, heating new hookups in this area are not allowed by Company policy, thus the need for new peak shaving capacity cannot be eliminated or reduced by controlling load additions.

In summary, the Council finds the Company's presentation of alternatives to the Danversport proposal to be exhaustive and the Council here determines that the proposed additions to the Danversport facility are the least costly and most reliable of the set of feasible alternatives.

G. Environmental Impacts of the Proposed Additions at Danversport

There are potentially five major environmental impacts associated with the Danversport proposal. They are: impacts during the construction phase, trucking impacts during the winter heating season, compressor noise impacts, the use of the system's "flare", and impacts to the Massachusetts Coastal Zone. Each will be briefly discussed below.

(1) Impacts During Construction

Construction activities to provide for the proposed additions to the Danversport LPA facility are estimated to take approximately 4-1/2 months after the acquisition and approval of construction bids. The activities to be conducted are: site preparation, forming and pouring the concrete foundation for the vaporizer, piping work for both liquid and vapor lines, electrical work, rigging, and painting, fencing and cleanup. Most of the piping and electrical work will take place within the process building which houses the existing vaporizers, compressors and controls. Heavy excavation and driving of piles are not required for the proposed project. Construction noise and dust should be very limited. Concrete deliveries for the vaporizer foundation and the use of cranes to move and set the vaporizer are the only activities involving heavy vehicles and their employment is expected to be brief. The Council finds that no substantial impacts exist during the construction phase.

(2) Trucking Impacts During the Operation of the Enlarged LPA Facility

Propane will be delivered to the Danversport plant by truck in sufficient quanties to ensure that at the beginning of each day's expected production of the storage tanks will be full. The amount of trucking necessary will be dependent upon the amount of gas sendout required. It takes approximately 10.9 gallons of liquid propane to produce an Mcf of vapor at 1,000 Btu/cf. Each truck contains approximately 9,000 gallons, which would support the production of 825 MMBtu. Table 5 shows the total estimated trucking traffic required by month during the 1982-83 heating season, under design conditions. It should be noted that the estimated trucking requirements under design year assumptions are effectively worse case estimates. This is particularly true of peak day trucking requirements. Normal requirements will always be less. The Danversport plant has three truck unloading stations.

The Company's Occasional Supplement identified four alternative trucking routes to the plan (Options A, B, C, and D). A fifth route ("E") was identified at the April 22nd Public Hearing. All routes

Table 5

Boston Gas Company

Danversport LPA Plant
Design Year Trucking Requirements

Month	Production Requirements (MMBtu)	Truckloads	Monthly Peak Day Truckloads
Nov. 1982	8,224	10	4
Dec. 1982	103,761	126	16
Jan. 1983	142,715	173	25
Feb. 1983	123,879	150	14
Mar. 1983	50,970	62	11
Apr. 1983	591	1	1
	430,140	522	

Source: Occasional Supplement

approach the plant from Route 128. The Company has provided USGS maps which trace options A thru D. (See Exhibits M and N, Occasional Supplement). The Council prefers options A and C, which approach the plant thru the main gate on Broad Street. Options B and D, which actually takes the trucks past fewer residential homes, are less desirable because of a hairpin turn off Endicott Street at Appleton Street, and subsequently entering the plant via its rear gate.* The Company should exercise its judgement carefully with respect to the trucking routes used, taking into consideration potentially hazardous

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* Option B would require LP trucks to exit Route 128 at Endicott Street in Danvers, cross two lanes of traffic in the process, and make a hairpin turn entering the rear driveway to the LPA plant. Option D would avoid the Endicott Street cross-over by having the LP trucks exit Route 128 at the intersection of Route 35 in Danvers and travel approximately 1 mile through town. The trucks would enter the facility by the same rear entrance but would approach the driveway on Endicott Street from the opposite direction as would be the case in Option B, thus avoiding the hairpin turn. At first blush option D would appear to be the best choice: avoiding the Route 128-Endicott Street cross-over, the hairpin turn and the residential neighborhood; however, for reasons similar to the concerns over the hairpin turn, this option is not favored for reasons of safety. Approximately thirty yards west of the rear entrance to the plant Endicott Street has a small, but steep incline. Approaching the rear entrance in an easterly direction (Option B), the driver of a vehicle cannot see a vehicle turning into the rear driveway until the crest of the incline. This would place a vehicle only thirty yards from an LP truck which would be turning across Endicott Street into the driveway under Option D. This potentially dangerous situation is made worse by the presence of six theatres and two shopping malls west of the plant on Endicott Street and the likelihood that LP trucks will be delivering propane during the worst weather conditions. The Council is concerned, especially because of the probability of young drivers exiting the theaters and taverns in the locale, that use of either routes outlined in Options B or D, would increase the possibility of a serious, life threatening accident. Testimony to this effect was given by local residents at the Public Hearing held in Danversport. Tr. Vol. 1, pp. 41-42.

winter road conditions. The fifth route alternative (Option "E" or "Soda Pop Lane") was discussed at the public hearing by a member of the community. This approach would have LP trucks make final approach to the plant travelling easterly on Route 35 (Water St.) and turn right onto property occupied by a newly constructed light industry office building. Trucks would traverse the length of that paved property, partly through a narrow driveway and exit at the rear of the property. The point at which the black top ends is approximately 1500 feet from the nearest gate to the plant.

Utilization of this alternative would require: acquisition of a right-of-way by the Company from the light industrial property owner; acquisition of the r.o.w. or title to the 1500' of undeveloped property; successful petition by the company to the Town to construct and use a roadway; and, compliance with any construction requirements necessary to ensure the integrity of the environment. The Council rejects this option for two reasons: the high additional cost imposed on ratepayers by construction of a road which would substantially increase the cost of the project; and, the uncertainty that the Company could acquire the necessary r.o.w.'s and permits for the roadway, with the attendant uncertainty as to the deliverability of energy supplies necessary to meet firm sendout requirements during the 1982-83 heating season. MGL Ch. 164 secs. 69I, 69J.

The Council also notes that the Condition attached to this Decision and Order regarding the use of "best efforts" pipeline deliveries, would potentially minimize the total trucking requirements necessary to meet the North Shore division's sendout requirements during the 1982-83 winter heating season.

(3) Compressor Noise Impacts

The four portable air compressors that are to be added to the plants (of which only 2 are permanent additions, as discussed supra), are fully enclosed within acoustical housings which are designed to limit the operational noise level to less than 76 decibels (db) at a distance of 7 meters from the enclosure. This design specification conforms to current EPA requirements concerning noise emission standards for portable air compressors. The nearest residential dwelling is located at a distance of approximately 200 feet from the compressors. At this distance, it is estimated that the noise level for the operation of all four compressors would be approximately 63 db (Staff Information Request, May 7, 1982). This level is external to any structure and would be further attenuated by the walls and windows of the surrounding dwelling. The Council also notes that compressor usage is greatest on extremely cold days when little outside activity occurs and when residential dwellings are presumed sealed to shut out the cold. The Council finds that there is no adverse noise impact associated with the proposed compressor addition to the Danversport plant.

(4) The Use of the Gas Flares and Its Impact

A component of the existing mixing and central system is a gas flare, located outside the process building at the rear of the site. This flare operates for two reasons. First, propane air mixture which is outside the interchangeability limits for natural gas must be discharged rather than fed into the distribution loop. This often occurs when LPA production starts up and lasts only until the proper ratio is attained. The second use of the flare is to discharge accumulated vapor from storage tanks and piping during maintenance.

Compared with the first use, the second use for maintenance purposes is relatively infrequent. the new electronic ratio control system to be installed at the plant is expected to reduce the need for the flare during startups of the plant. Thus during normal operation of the facility, noise impacts of the flare are expected to be reduced by the proposed new additions at Danversport.

(5) Coastal Zone Management

The Siting Council has expressly adopted Massachusetts Coastal Zone Management Policies Nos. 8 and 9 pursuant to Council Regulations 81-84 (980 CMR parts 8.01 - 8.01). In doing so, the Council has accepted the role of protector of the Massachusetts coastal environment from unnecessary intrusion of energy facilities. The present Danversport LPA facility is entirely within the boundaries of the Massachusetts Coastal Zone (see: MCZM Plan; Vol. II).

Recognizing this fact, on April 26, 1981, the Council Staff submitted copies of the Company's Occasional Supplement to the General Counsel of the Executive Office of Environmental Affairs and to the Director and General Counsel to the Massachusetts CZM and subsequently visited the site with CZM staff. Pursuant to EFSC Rule 81.1(5)(1) [980 CMR part 8.01(5)(1)] a proposed facility which is "...ancillary to an existing use and which does not substantially alter the environmental impact at the primary site," may be exempt from CZM policy No. 8. We find that this proposal fits within such an exemption.

The facility to which improvements are proposed has existed since 1951. The improvements will affect the coastal environment in no detrimental way: they will not have any detrimental aesthetic impact, no detrimental physical impact, and they will not impede the use of the coastal environment by either recreational or commercial users. There will be no change in the existing land use of the property under the proposed improvements and no additional adverse impacts on the coastal zone. There is, however, a possibility that during installation of the vaporizer, excavation activities could increase the turbidity of the Water's River estuary. The Company has assured the Council that they will take sufficient care to avoid causing any such problem during installation. Although the total excavation will be small and the use of the coast in the Water's River area is predominantly heavy industrial, we feel that pursuant to EFSC Regulation 81 we must condition our approval to the effect that the Company may not dispose of any construction debris on the South side of the facility which borders the Water's River, and that the Company take certain measures, specified in Condition 1, 5 and 6, to minimize the impact of construction activities on the coastal environment.

The Council finds that the proposed improvements are not inconsistent with the inland and coastal wetlands restriction programs (M.G.L. Ch. 131, 40A; Ch. 130 sec. 105); the Scenic Rivers Act (M.G.L. Ch. 21, sec. 17A); the Ocean Sanctuaries Act (M.G.L. Ch. 32A, Secs. 13-17, 18). The Council, then, determines that the proposed improvements to the Danversport facility, if carried out properly, will have no adverse impacts on the Massachusetts Coastal Zone, either during construction or while in operation. We further conclude that approval of this facility is consistent with Policy No. 8 of the CZM plan and EFSC Regulation 81.

H. Conclusions

The Council hereby APPROVES the Boston Gas Company's Occasional Supplement to their Second Long-Range Forecast of Gas Needs and Requirements, subject to certain conditions described below.

The Company is ORDERED to commence construction of the additions to the Danversport LPA plant, as soon as possible.

This Decision and Order is subject to the following conditions:

(1) That the Company not dispose of any construction debris on the south side of the facility site which borders the Water's River;

(2) That the Company make every attempt to utilize "best efforts" pipeline deliveries, beyond MDQ, to the North Shore division during the 1982-83 Winter heating season, but only if such deliveries are not inconsistent with maintaining a least-cost mix of resources throughout the Company's service territory;

(3) That in the Company's next Supplement filing it propose the formal rescission of the Council's July 21, 1980 Order* which approved the addition of a 15 MMcf/day LNG vaporizer at the Salem LNG facility, or state why such a proposal would not be wise;

(4) That the Company meet with the appropriate officials from the Department of Public Utilities, the Town of Danvers, and/or Essex County, come to an agreement as to truck routes and delivery schedules to be followed for the delivery of propane

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* 4 DOMSC 50, 81 (7/21/80).

to the facility and report the results of the deliberations to the Council prior to the commencement of the next heating season;

(5) That the Company utilize, during construction, sedimentation control measures such as hay bales or synthetic fabrics between the construction site and storm water retention pond;

(6) That the Company utilize, during construction, sedimentation control measures such as hay bales or synthetic fabrics around storm drains within or heading from the construction site; and,

(7) That the Company keep the Council and staff apprised of the progress of the repairs to the Salem LNG tank, specifically to include a copy of the final repair cost estimate and repair timetable as soon as they are available.

Paul T. Gilrain, Esq.
Hearing Officer

This Decision and Order was approved by unanimous vote of the Council by those members present.

Voting in the Affirmative: Margaret N. St. Clair, Esq., Secretary of Energy Resources; Bernice McIntyre, Esq., designee of the Secretary of Environmental Affairs; Noel Simpson, designee of the Secretary of Economic Affairs; Dennis Brennan, Esq., Public Gas Member; Thomas J. Crowley, P.E., Public Engineering Member.

Ineligible to Vote: Charles Corkin II, Esq., Public Oil Member; Harit Majmudar, Ph. D., Public Electricity Member

/S/

Margaret N. St. Clair, Esq.
Chairperson

Dated at Boston this 24th day of May, 1982.

APPENDIX "A"

M E M O R A N D U M

TO: Bernice McIntyre, Counsel, EOEA

FROM: Gary Clayton, CZM

DATE: May 20, 1982

SUBJECT: Boston Gas Company - Danversport LPA facility expansion

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Purpose

On May 19, 1982, I met with Paul Gilrain, Hearing Officer for the Energy Facilities Siting Council, at the Boston Gas Company's propane/air production (LPA) facility at Danversport. The purposes of this site visit were to evaluate: 1) the impacts on the coastal environment assicated with the construction of the ancillary facilities at the LPA gas facility and 2) the impacts of a proposed service road south of the plan site on the coastal zone.

Site Description

The LPA facility is located on industrially zoned land all of which is within the Massachusetts coastal zone. The industrial area is bounded on the north by an adjacent residential area and to the south by the Waters River. The other site margins are comprised of railroad and highway embankments. In addition to the LPA facility, this industrial land includes a propane gas distributor, (Eastern Propane Gas Co.), an oil tank farm and a chemical company. A railroad spur also crosses this industrial land and provides propane by railroad tank car to the propane gas distributor. The Boston Gas Company LPA facility is about 1000 feet from the Waters River and is separated by: 1) a berm which is constructed around the oil tank farm, 2) the railroad spur embankment and 3) several acres of land characterized by a dense stand of phragmites reed grass. This vegetation typically becomes dominant in wetland areas which have been disturbed by filling with debris or other material such as dredged spoils. This reed grass area next to the Waters River has evidently been altered.

The Waters River is part of an urban estuary which contains shellfish, finfish, and salt march resources.

The area separating the Boston Gas LPA facility from the Waters River is alrgely floodplain and is characterized by a high groundwater table. There are drainage ditches across this area as well as a small (approx. 100 feet in diameter) stormwater retention pond located adjacent to the LPA facility. No surface tributaries to this pond are evident, although a storm drain pipe from the LPA facility discharges directly into the pond. The only observed outlet to the pond is a small drainage ditch. Movement of water in this ditch was not observed during the site visit. Mr. Gilrain indicated that culverts presumably connect this drainage ditch with the large phragmites stand which is situated between the railroad sput embankment and the Waters River. Culverts in this area, however, are likely to be subject to regular blockage due to the large volume of plant material produced by the phragmites.

The water in the pond and ditch probably reflect existing ground water levels. There was no evidence of regular, periodic water fluctuations in the ditch or pond as might be expected if these water bodies were directly connected to the tidal river. Given the slope of the land, groundwater movement in this industrial area is, however, probably in the direction of the Waters River.

In summary, all of the land lying between the LPA facility and the Waters River appears to have been substantially altered.

Assessment

There are no serious impacts to coastal resource areas expected from the construction of the ancillary facilities at the LPA facility. The conditions to be imposed on this construction will help avoid any filling or alteration of the adjacent floodplain by debris disposal or sedimentation. However, additional conditions such as the use of hay bales will further limit any runoff/erosion problems. In addition, erosion control devices will be needed around stormwater drains which are within the construction area.

The construction of a new road on property owned by a third party sourth of the LPA facility would extend linearly over a 1000 feet. The area to be impacted by this new road appears to be all upland. No wetland areas are involved. This service road would be seaprated from the Waters River by nearly 900 feet of "land" as previously described in the "site description". The area of any risk to coastal resources is the stormwater retention pond adjacent ot he LPA facility. A spill of propane by a delivery truck might contaminate the pond and adjacent wetland/ditches and flow in the direction of the river. The effect of a spill on coastal resources within the Waters River from the pond and ditches is low given the volatile properties of propane and adsorptive capacities of the organic soils found between the pond and the river. However, the road can be designed so that the risk of any contamination is greatly reduced. For example, the use of berms, guardrails, lighting, sealed road surfaces and subsurface collection systems can help avoid accidents or contain spills away from any drainage system.

Recommendation

1. Incorporate language into the final EFSC Order requiring the use of sedimentation control materials such a hay bales or synthetic fabrics between the construction site and the stormwater retention pond.

2. Incorporate language into the final EFSC Order requiring the use of sedimentation control materials such as hay bales or synthetic fabrics around storm drains within the construction area.

3. I do not believe that the proposed service road "could substantially impact the coastal zone". An adequately designed service road can greatly diminish the risk of a propane spill. Even if a spill were not contained, the likelihood of serious impact to the coastal resources within the Waters River are low given the volatile nature of propane, the distance separating the facility from the rive, and the adsorptive capacity of the organic soils within the industrially zoned area. The risk to coastal resources with the proposed new service road appears less than the utilization of the existing road where a spill would flow into storm drains which probably flow directly to the nearest coastal water course.

   The service road would also not impact the coastal recreational or visual resources of the area.

   Finally, the service road and any potential problems associated with a spill might be further lessened through the shortening of the service road by relocating the fence gate of the LPA to the east.

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Blackstone Gas Company for the Approval of a Long-Range Forecast of Gas Needs and Requirements	EFSC No. 81-42

FINAL DECISION

Paul T. Gilrain, Esq.
Hearing Officer

I. INTRODUCTION

The Council hereby APPROVES the Second Long-Range Forecast of Gas Needs and Requirements of the Blackstone Gas Company subject to the condition stated in the Decision and Order in part III infra.

II. ANALYSIS

A. Sendout and Resources

Blackstone Gas Company ("Blackstone" or "The Company") is the smallest gas company doing business in the Commonwealth.[1] Their annual sendout for the split-year 1980-81 was 45.5 MMCF and their peak day sendout was approximately 0.320 MMCF. Thus the Council is aware that the resources of a company the size of Blackstone are extremely limited and the appropriateness of its forecasting methodology must be considered against the backdrop of the factual circumstances of the particular service territory.[2]

The Company has a total requirements contract with the Tennessee Gas Transmission Company to supply it with an annual volume of gas up to its Annual Volumetric Limit (AVL) of 60.9 MMCF.[3] This represents an annual reserve of 25.3% in the first year of the Forecast and 13.8% in the last year of the forecast period when sendout is forecast to be 52.5 MMCF/year.

As the Council noted in its last decision on Blackstone, the Company does not forecast peak load and is formally exempted from

1 Blackstone has between 480-490 customers.

2 In Re Blackstone Gas, 6 DOMSC 66, 67-8.

3 The AVL is the limit placed on the annual quantities of gas which the F.E.R.C. allows TGT and Blackstone to contract for.

forecasting peak and filing Table G-5.[4] However, the Company did supply the Council with city-gate take station weekly meter readings for February, March and May of 1981. From these figures, and discussions with the Company, peak load appears to be approximately 0.450 MCF/day. This number was very roughly calculated by dividing average weekly sendout by the aggregate number of degree day's at Logan International Airport for the same time period. This yielded a result of Company use per degree day of .0074 MCF. This result is acceptably consistent with other gas company forecasts. If that use factor is multiplied by the historical peak day at Logan of 61 DD (January 4, 1981) the peak is 0.450. This "design" peak for the Company still allows them an 11% reserve on peak day. In addition, the Company maintains the ability to receive gas on short notice through an existing interconnection from its former service territory in Rhode Island (Valley Gas Company) in case of emergencies. Lastly, all of the Company's customers are residential and therefore classified as FERC Priority One and are not subject to curtailment.

In its last Decision and Order, the Council directed the Company to comply with four specific conditions, (in addition to exempting them from filing Table G-5 peak information). These are attached as Appendix "A". The Company has satisfactorally complied with each condition as follows:

4 id, 6 DOMSC at 69 (1981).

1. Condition No. 2: The Company has informed the Council of actual experiences which affect its forecast. Such experiences include: the end of gas main disruption due to sewer construction; the sealing of cast iron pipe in their six inch main; and the implementation of prompt follow-up of leakage surveys. All of these have resulted in the reduction of "unaccounted for" gas and reduced sendout. The Company has monitored growth near its mains and reported that housing starts are minimal. They emphasize that, with a staff of four, in toto, each officer of the Company has read each meter in the service area (the Town of Blackstone and the southern half of the Town of Bellingham) "on scores of occasions"[5] and such actual experience with the service territory serves as a practical basis for anticipating supply and distribution problems. The Council takes particular note of this Company's efforts in this regard and considers such "hands-on" experience to be an appropriate forecasting mechanism for a company of this size.

2. Condition No. 3: In discussing conservation within its service territory, the Company has noted that in the years following 1977, use of more efficient appliances, the lowering of thermostats, and household weatherization had the effect of lowering normal sendout. The Company has observed that this trend seems to have stabilized in the 1980 to 1982 period. The Company attributes this conservation to cost of

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5 Letter from Company President Ralph Sullivan, dated August 5, 1981.

gas increases and governmental policies. The conclusions of the Company were based on their knowledge of the service territory, which again, in this case, is appropriate. The Council is concerned that future gas price increases will further reduce customer demand and increase the bad debt problems of the Company. The Condition to this Decision addresses this problem.

3. Condition No. 4: The Company has complied fully with this Condition by supplying all of the Gas Statement-Details submitted to it by Tennessee.

4. Condition No. 5: The Company has demonstrated, in fact, its ability to cope with an extended "cold snap" during the winter of 1980-81. During that time the Company never exceeded 90% MDQ of its MDQ of 505 MCF. They have never historically exceeded that figure nor have they ever approached exceeding their AVL. Applying this temperature scenario to the last year of the forecast period shows that the Company will still have sufficient resources to meet sendout requirements.

The Council is therefore satisfied that the Company can meet its gas needs throughout the forecast period in terms of total load, peak day, and for an extended "cold snap" as was experienced during the winter of 1980-81.[6]

B. Summary

The Company is capable of meeting its forecast sendout requirements during the forecast period, and its forecast of sendout was appropriate

6 We note that actual experience during that period demonstrated the Company's ability to do just that.

to its service territory. The Company has promptly responded to Council inquiries in a cooperative manner. Since the Company does not peak shave and is an all-requirements customers of the Tennessee Gas Pipeline, there is some concern as to how the Company would supply its system in the event of a pipeline interruption. Since that situation has occurred during the past year, the Council is Conditioning this Decision and requiring that the Company demonstrate how it did, and would, cope with a future pipeline interruptions.

III. DECISION AND ORDER

The Council hereby APPROVES the Second Long-Range Forecast and First Annual Supplement of the Blackstone Gas Company and ORDERS that it meet the following Conditions in its next Supplement:

1. In its next Supplement, the Company shall address the anticipated effects of price decontrol of natural gas on its forecast of sendout. This analysis should include both sendout data and anticipated problems with customer accounts receivable.

2. The Company shall submit to the Council an explanation of how it would meet its sendout requirements in the event of a pipeline interruption on the Tennessee system, and, specifically, explain how it met its sendout requirements during the pipeline interruption in 1981.

Paul T. Gilrain, Esq.
Hearing Officer

The Energy Facilities Siting Council approved this Decision and Order by Unanimous Vote on May 24, 1982

Voting in Favor: Margaret N. St. Clair, Esq., Secretary of Energy; Sandy Uyterhoeven, designee for the Secretary of Environmental Affairs; Noel Simpson, designee for the Secretary of Economic Affairs; and Richard Pierce, designee for the Secretary of Consumer Affairs.

Ineligible to Vote: Harit Majmudar, Public Member - Electricity; Charles W. Corkin II, Esq., Public Member - Oil.

/s/

Margaret N. St. Clair
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

Middleborough Gas and Electric	)	
Department's Second Long	)	EFSC No. 81-18
Range Forecast of Gas Needs	)	

FINAL DECISION

Lawrence W. Plitch, Esq.
Hearing Officer

May 24, 1982

Final Decision

The Energy Facilities Siting Council hereby APPROVES the Second Long Range Forecast of Gas Needs of the Middleborough Gas and Electric Department (hereinafter "Middleborough" or "the Department") subject to the conditions noted in the decision. As explained in more detail below, the Department has demonstrated that a small municipal gas department with limited staff and resources can submit a well-reasoned forecast in satisfaction of the Council's regulatory requirements.

Middleborough filed its forecast on August 17, 1981. Staff Information Requests were sent out on March 11, 1982. Notice of filing was published in local newspapers once each week for three consecutive weeks beginning March 18, 1982. The Department's response to the Staff Information Requests was received on March 26, 1982. There being no petitions to intervene and no proposed facilities, it was decided to adjudicate the forecast without formal hearings.

Analysis

The focus of this Decision is the Department's compliance with the five conditions to the Council's Order regarding Middleborough's previous forecast, EFSC No. 80-18. As will be discussed, the Department's efforts to satisfy the Council's concerns were, for the most part, successful. The Council encourages the Department to continue its efforts at improving the quality of its forecasts in the coming years.

1. That the Department, in its next filing, include a description of the methodology used to prepare its forecast of load requirements. Calculations, seasonal and class breakdown percentages, base load and heating factors, and the bases for these factors, must be included in this description.

The Department responded to this condition, both in its forecast and its answers to the Staff Information Requests, by providing a more detailed account of its calculations and justifications. The methodology is described at length and the analyses are accurate, reasonable and reviewable. For example, the narrative contains a lengthy explanation of the various factors that the Department has used to forecast changes in the number of customers in each customer class. In addition, the calculation of base load and heating factors are represented in extensive tables and accompanied by clear and concise explanations. Finally, each customer class has been segregated and analyzed as to temperature effect on sendout and base usage.

The only statistical factor in the forecast that gave the Council pause was the Department's methodology for calculating its design-year. Middleborough uses the number of degree days in the average of the five highest split-years in the last 25 years. This standard may have a tendency to understate the sendout a system should be "designed" for. As a result, the Department was asked during discovery (Info. Req. No.8) to recalculate its forecasted sendout under a scenario that included a split-year equal in degree-days to the highest split-year in the past 25 years. This figure (6650 DD) was 2.4% colder than the average-based design-year that had been used by the Department in its Forecast. Through its answer, the Department demonstrated its ability to meet the needs of its customers should any of the years during the forecast period be as cold as the stricter design-year standard.

It is not the province of the Siting Council to tell a gas company what methodology it should use to calculate a design-year standard. However, the Council does feel strongly that Middleborough's supply picture over the forecast period should be sufficient to meet the coldest split-year reasonably likely to occur. As such, it is a Condition of this Order that the Department analyze and discuss its ability to meet the gas needs of its system in the event that a forecasted split-year is as cold as the coldest split-year that has occurred over a given period of time. The Council has accepted, as reasonable, design-year methodologies that use data from periods as short as 15 years and as long as 25 years.

2. That, in its next filing, the Department describe the relationship between the judgements and references made in Section 1 and the forecast of requirements and supply in later sections.

This condition has been adequately addressed in the present filing and has not generated any further conditions. Generally speaking, there is a much better "fit" between the introductory narrative discussion and the accompanying tables in the Forecast (see discussion of Condition 3, infra). The continued improvement in this linkage is encouraged by the Council.

3. That, in its next filing, the Department report what effect customer conservation measures have had and may have on its future load requirements, and explain the bases for such judgements.

In its Forecast narrative, the Department was "unable to substantiate the effects of conservation on future load requirements" due to "the lack of accurate historical data of heating and non-heating customers".

However, in response to Staff Information Requests, the Department was able to analyze and discuss historical usage patterns in the context of conservation measures, albeit by customer class only. The results of this analysis show the largest reduction in usage by the commercial class, while the industrial class has actually increased its MCF per customer consumption. The problem generated by the analysis presented is that it is not reflected in the Forecast projections. Similar to the concerns expressed in regards to Condition 2 to EFSC Decision & Order No. 80-18, there is reason to doubt that the actual forecast projections in Forms G-1 through G-5 reflect the totality of experience that is evidenced by answers to the Staff Information Requests. For example, in spite of the fact that Middleborough's response to Staff Information Requests No. 2, 3 and 4 indicates a 12.2% conservation rate in the commercial class and a 30% increase in industrial usage, forms G-3(A) & (B) show a constant consumption rate over the forecast period for both classes. In the absence of some words of explanation, this serious discrepancy must be challenged as unreviewable and unreasonable.

A possible answer may be that the data analysis was performed months after the Forecast was prepared. However, this would only point out a lack of adequate Forecast preparation and thought. In any case, it is imperative that the Department incorporate its conservation judgements into its forecast preparations. The satisfaction of this requirement in future Forecasts is hereby made an explicit Condition to the approval of this Forecast. This Condition includes the requirement that the residential customer class data be disaggregated by heating and non-heating subclasses, as suggested by the Department on pages 2-3 of the Forecast.

4. That, when the consultant's report to Middleborough is completed, the Department make a copy available to the Council.

This report was in fact promptly furnished to the Council on April 24, 1981. (See discussion of Condition 5, infra.)

5. That the Department discuss, in its next filing, its decision to contract for additional gas from AGT in light of its concerns over the capacity of its low pressure system to handle additional load.

At the time that Middleborough submitted its 1980 Forecast, November 24, 1980, there was a concern on the part of the Department that its low pressure distribution system did not have sufficient cpaacity to handle the new supplies needed to meet the "substantial increase in the number of requests for gas" (page 5 of Fourth Annual Supplement, EFSC No. 80-18). In response to this problem, the Department placed a moratorium on new heating loads and hired a consultant to perform a Gas Distribution Analysis. The study produced an analysis projecting exactly at what points in the Department's distribution system, the pressures would need reinforcement in the event various increased levels of supply were added. Upon independently verifying the consultant's findings, the Department followed the study's recommendations and installed 6500' of high pressure main and two additional low pressure system feeds. This enhanced low pressure system was reported to be operating satisfactorily during the winter of 1981-82 (Staff Information Request No. 5). As a result, the Department feels fully capable of handling new supplies of gas, regardless of whether they result from the New England States Pipeline project, a new contract with Commonwealth Gas Company or some other source. The Council, upon review of the consultant's study (Condition No. 4) and the Department's Second Long-Range Forecast, is similarly satisfied.

6. In addition to the two conditions generated by the Department's actions in response to the most recent Decision and Order (see paragraphs 1 and 3 above), the Council is imposing a new Condition upon Middleborough. In its next Forecast Supplement, the Council would like to see presented an analysis of the Department's plans for meeting the demands of its customers in the event each of its major gas supplies is disrupted. This analysis will effectively present a set of contingency plans for each of the Department's most threatening peak-day supply disruption scenarios, e.g., loss of Algonquin pipeline supply, inability to purchase LNG from Bay State, etc.

ORDER

Given the foregoing considerations and comments it is hereby ORDERED that the Second Long-Range Forecast of Gas Needs, as submitted by the Middleborough Gas and Electric Department, be APPROVED subject to the Conditions noted in Paragraphs 1, 3 and 6 above.

Lawrence W. Plitch, Esq.
Hearing Officer

This Decision was approved by a vote of 5-0 by the Energy Facilities Siting Council at its meeting on May 24, 1982, by those members or their representatives present and voting.

Voting in Favor: Margaret N. St. Clair, Bernice McIntyre, Noel Simpson, Dennis Brennan, Thomas Crowley.

Ineligible to Vote: Harit Majmudar, Charles Corkin

Date

Margaret N. St. Clair
Chairperson EFSC

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

Haverhill Gas Company Second Long-Range Forecast of Gas Needs and Requirements	)	EFSC 81-15

Final Decision

Paul T. Gilrain, Esq.
Hearing Officer

Margaret Keane
Staff Economist

June 2, 1982

I. Introductions

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

The Haverhill Gas Company serves customer in 16 cities and towns in northeastern Essex County. Its annual sales in 1980-81 were 4,035 MMcf, making it the 7th largest gas company in the Commonwealth.

The Haverhill Gas Company ("Haverhill" or "the Company") filed its Second Long-Range Forecast on August 5, 1981. The Council then ordered publication of a notice of public hearing and adjudicatory proceedings in newspapers of general circulation within the service area of the Company. On October 2, 1981, a pre-hearing conference was held at the Council offices. There were no intervenors or interested parties present, nor did any come forth during the proceedings.

After a number of rounds of discovery and technical sessions were completed, it was agreed that no formal hearing would be necessary as a sufficient record had been compiled. The Hearing Officer moved the record into evidence and a "desk review" was conducted.

II. Previous Conditions

The Council's decision in the review of the Company's Fourth Supplement imposed four conditions. They were:

1) A discussion of the impact of unauthorized conversions on the system and measure taken to prevent such conversions.

2) A discussion of the status of the Boundary gas project, including, contingency plans in the event the project is not approved or is delayed.

3) A description of assumptions of plans with respect to "best efforts" delivery of underground storage gas.

4) With regard to dissaggregation of customer classes, a description of judgements and the basis for them.

The Company does not see unauthorized conversions as a problem, given that a signed authorization form must be issued by the Company before a heating permit is issued to a heating contractor by a city or town. Further, the Company's computer billing system monitors for excessive usage in the non-heating customer class.

With respect to Condition 2, the Boundary project is discussed infra. While the Council is pleased to note that the Company does not plan to have access to Boundary supplies until 1983, the Company is urged to continue closely monitoring the status of this project. As regards Condition 3, most of the Company's best efforts storage has been upgraded to firm, as discussed infra at 9.

With respect to Condition 4, the Council's opinion is that the Company has complied and is further discussed in the analysis of the Company's sendout forecast.

III. <u>Methodology</u>

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

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

A. NORMAL YEAR

A "normal" year is defined as a year that is neither warmer nor colder than average. The Company receives a service-territory specific Annual Degree Day Report from Stone & Webster Engineering Corp. Normal Year Effective Degree Days are based on the arithmetic monthly average from the Stone & Webster report. Thus the Company utilizes a normal year consisting of 6941 effective degree days based on a 20 year average.

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

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1 (Forecast p. 6).

FIGURE 1

The Company gives the following example:

For January 1982, Residential Heat Class:

Base Use = .098 X 19,059 X 3 = 57,9000 Mcf

Monthly Heat load = Heat factor X Number of Customers X Effective Billing Degree Days[2]

In the same example:

Heat Use = .013 X 19,059 X 1,301

= 322,300 Mcf

Total Monthly Use = Base Use[3] + Heat Use[4]

Total Month Use = 57,900 + 322,300

= 380,200 Mcf[5]

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

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

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

5 (Forecast, p. 6)

The Company used this method on a monthly basis and aggregated it annually by class to attain total monthly and annual firm sales.

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

B. DESIGN YEAR

A "design year" is defined as the coldest year for which a Company plans to meet its firm customer requirements. The Company used a design year consisting of 7781 effective degree days ("EDD") based on April 1966 through March 1967 data[6]. The Company states, "We have used a Design Year based on the actual period from April 1966 to March 1967, without alteration; the coldest experienced in 20 years".

Design year sendout was calculated as follows. The Company assumed that base sendout was the same in both normal and design years. As shown on Table DD in the forecast, design EDD were 11.2% greater than normal in the summer season and 8.2% greater in the winter season. The temperature sensitive portion of sendout was increased by these percentages to arrive at the design heating load.

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

6 Stone & Webster Management Consultants, Weather Analysis System, Haverhill Gas Company, "Normal Weather frequency August 1960 - August 1980".

class sendout as shown on page 8a.[7]

C. PEAK DAY

A "peak day" is the coldest day that is likely to occur during a twelve month period. The Company used a peak day of 76 effective degree days which is the maximum peak day experienced in the Haverhill system in the last 20 years. This is an increase from the peak day of 68 EDD used in the Third Supplement and the peak day of 72 EDD used in the Second Supplement. The Company states, "We will continue to use this figure (76 EDD) as our criterion until a future colder period is experienced.[8]

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

D. CUSTOMER USE FACTOR

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

In the Residential General class, the 1981 actual base factor of .053 Mcf/cust/day was judged to be low as a result of extremely hot weather and was normalized to .055 Mcf/cust/day.

The 1981 actual heat factor was 1.08 Mcf/cust/EDD. The Company attributes this increase to the use of "distress heating". They state, "Customers used their ovens in an attempt to keep warm during the severe cold weather in the January billing cycle.[9] With trending, the January

7 Forecast, p. 8a.
8 Forecast, p. 1.
9 Forecast, p. 3.

heat factor declines to .86 Mcf/cust/EDD.

With respect to the residential heat class, the base heat factor is declining[10]; .102 Mcf/cust/day in 1979 to .101 Mcf/cust/day in 1980, .098 mcf/cust/day in 1981 and forecasted to decline to .0960 Mcf/cust/day by 1991. This decline can be attributed to a number of factors. A significant percentage of the base load is water heating; conservation has resulted from the increased use of higher efficiency appliances. Average use/customer in new homes average 93 Mcf/year versus 118 Mcf/year in existing homes. The company attributes this 21.2% differential to better insulation and energy efficient appliances utilized in construction of these new homes[11]. Overall, the Company sees the decline in base factor as attributable to increased efficiency of appliances and a reduction in customer usage, particularly in the fringe months of the heating season.

The Residential Heat factor has increased somewhat from previous projections due to the addition of new Residential Space Heating Customers who have converted from No. 2 fuel oil. The Company states, "Upon application for service these customers oil usage is converted to mcf gas sales. In our opinion it appears that these customers are just looking for an economic savings and do not practice conservation techniques for the first few years".[12]

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

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

12 EFSC 81-15, Information Request No. 4.

Base and heat factors in the Commercial and Industrial Sectors are calculated individually, while the smaller customer projections were calculated from historical data and information from the Company's Marketing Department.

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

IV. Application of Review Criteria to Company Forecast

The Company's forecast methodology is clearly presented, thoroughly documented, and all judgements are explained. The Company's in-house 10 year sales forecast was a beneficial addition to the Supplement. Haverhill has gone well beyond the requirements of the regulations and presented a thoroughly reviewable forecast. The Company is lauded for its progress and cooperation.

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

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

A. Supply Contracts and Facilities

(1) Pipeline Gas

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

The Company has two storage contracts of 350 MMcf each with Consolidated Gas Supply Corp and National Gas Fuel Storage, both of which will extend beyond the duration of the forecast period. Tennessee will transport firm or best-efforts gas under both contracts. From November, 1982 on, the NGFS contract is reported as Penn-York Underground Storage Service.

Effective November, 1981, the Company has received approval for firm delivery of 4 MMcf/day (3.2 MMcf Consolidated .8 MMcf Penn-York) of underground storage versus its previous supply of 3.18 MMcf of best efforts delivery. Given that previous best efforts deliveries were an average of 1.5 MMcf/day in 1980-81, this is an increase of 2.5 MMcf/day.

(2) LIQUEFIED NATURAL GAS

The Company purchases liquefied natural gas (hereinafter LNG) from Distrigas of Massachusetts under a contract that extends until 1998. The Company expects less than the contract quantities of 290 MMcf to be delivered, based on historical delivery of 80% of contracted supplies. The Company also has a contract for the purchase of LNG from Bay State Gas Company which runs through 1991, providing for both firm and optional amounts, i.e., 50 MMcf/yr. +25 MMcf if needed for the 1981-82 split year. The purchase of the optional amounts is determined by Haverhill based on its need.

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

(3) PROPANE

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

B. COMPARISON OF RESOURCES TO REQUIREMENTS

(1) NORMAL YEAR

The Company expects to meet total sendout requirements during the forecast period under normal weather conditions as illustrated on Table G-22. (Forecast) Pipeline gas from Tennessee is expected to provide 96% of the non-heating season load and approximately 82% of the heating season load. LNG provides approximately 4% of the non-heating season load and 8% of the heating season load. Propane is expected to be less than 1% of heating load. It is anticipated that Boundary Gas[13] will provide 8% of heating supply.

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

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

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13 On December 19, 1980, Boundary Gas, Inc. applied to the ERA for authority to import a total of 185,000 Mcf per day of Canadian natural gas for 10 years. Boundary is composed of thirteen natural gas distribution companies and the Tennessee Gas pipeline Company. 29% of the gas will be distributed in New England. In Massachusetts, Bay State Gas will receive 19 MMcf/day; Boston Gas, 13.9 MMcf/day; Haverhill Gas 3.2 MMcf/day; Berkshire Gas 2.1 MMcf/day; Fitchburg Gas 1.05 MMcf/day. Haverhill expects this supply to be available in November, 1983.

2. Curtail all non-firm sales.

3. Temporary spot purchases of propane and/or LNG at reasonable prices.[14]

(2) DESIGN YEAR

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

(3) PEAK DAY

The record indicates that Haverhill will have more than adequate resources to meet forecasted Peak Day Sendout requirements during the forecast period. The Company forecast lists 51 MMcf available to meet peak day requirements of 41 MMcf in 1982/83. With the Company's decision that Boundary Gas supplies will not be available until November 1983 the maximum available supply is reduced to 48 MMcf, still more than necessary to meet peak day sendout requirements. If the maximum daily quantity of pipeline gas and firm storage gas is available and the propane air and LNG facilities are operable at maximum daily capacity, the Company potentially has 15-25% more supply available than is necessary to meet the peak day load at various points in the forecast period. It is also to be remembered that Haverhill has an unusually high peak day of 76 effective degree days.

14 (p. 9, Forecast).

(4) COLD SNAP

A "cold snap" is a series of continguous peak days, such as the two to three week period experienced during the winter 1980-81. Such periods represent particular planning problems for gas utilities different from meeting needs on one extremely cold peak day, or meeting the needs of an entire heating season.

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

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

V. ORDER

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

1. That, in its next filing, the Company consider customer use data, particularly appliance saturation surveys, generated by the electric utilities whose service territories are coincident to that of Haverhill. The EFSC Staff can provide assistance in this regard to help identify the appropriate documents.

Paul T. Gilrain, Esq.
Hearing

Date at Boston this 2nd day of June, 1982.

This Decision and Order was approved by unanimous vote of the Council by those members present.

Voting in the Affirmative: Margaret N. St. Clair, Esq. Secretary of Energy Resources; Bernice McIntyre, Esq., designee of the Secretary of Environmental Affairs, Noel Simpson, designee of the Secretary of Economic Affairs; Dennis Brennan, Esq., Public Gas Member; Thomas J. Crowley, P.E., Public Engineering Member.

Ineligible to Vote: Charles Corkin II, Esq., Public Oil Member; Harit Majmudar, Ph. D., Public Engineering Member

/S/

Margaret N. St. Clair, Esq.
Chairperson

Dated at Boston this 2nd day of June, 1982.

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Northeast Utilities Companies for Approval of a Long Range Forecast of Electric Needs and Requirements	EFSC No. 81-17

FINAL DECISION

Paul T. Gilrain, Esq.
Hearing Officer

On the Decision:

John Hughes, Chief Economist
Margaret Keane, Staff Economist
JoAnne Bos, Staff Economist

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I. INTRODUCTION

The Council hereby APPROVES, subject to certain conditions contained in part VIII infra., the Second Long Range Forecast[1] of the Northeast Utilities System Companies[2] ("NU" or the "Companies"). In this decision we will look at the background and history of the procedings in part II, the scope of our review in part III and the standard of review which the Council applies to electric company's in part IV. A comprehensive analysis of the Companies' demand model and forecast is found in part V, and of their supply model in part VI. Finally, our conclusions are contained in part VII, the decision and order.

II. HISTORY AND BACKGROUND OF THE PROCEEDINGS

The history and background of this proceeding spans two and one-half years and this review will consist of an assessment of the cumulative forecast produced by the Companies' 3rd and 4th Supplement to their First Long-Range Forecast as well as their Second Long Range

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1 As will be discussed in Section II, infra., the Council's last decision on a forecast submitted by the Companies was December 5, 1978; 3 DOMSC 37. This review encompasses the Companies' filings in 1979, 1980 and 1981.

2 Northeast Utilities is a public utility holding company and is the sole owner of all of the outstanding shares in even of its subsidiary companies: The Connecticut Power and Light Company ("CP&L"); The Hartford Electric Light Company ("HELCo"); Western Massachusetts Electric Company ("WEMCo"); Holyoke Water Power Company ("HWP") and its subsidiary Holyoke Power and Electric Company ("HP&E"); Northeast Nuclear Energy Company; ("NNEC"); and the Northeast Utilities Service Company ("NUSCo").

Of these Companies CL&P and HELCo are part owners of existing generating units in Massachusetts but do not have service territories in the Commonwealth. NNEC is a Connecticut corporation empowered to generate, transmit, distribute or sell electricity for ultimate use by fifty persons and authorized to do business in the Commonwealth. HWP and WEMCo are Massachusetts electric companies.

Forecast. In April of 1979, the Companies filed timely their 3rd Supplement to their First Long-Range Forecast. However, because the Companies' internal forecasting schedule did not allow for that filing to consider the conditions imposed by the Council in its decision on the 1978 Supplement[3] the Hearings Officer suspended that review (EFSC No. 79-17) and ordered it combined with the Companies' 1980 filing, due on April 1, 1980. A copy of that Memorandum and Order, dated 16 January, 1980 is attached hereto as Appendix "A".

The Company filed its 4th Annual Supplement in a timely fashion. On April 9, 1980, an Order of Notice was issued to the Companies, setting May 12th, 1980 as the date for a pre-hearing conference the beginning of proceedings. The Attorney General, who had intervened during the 79-17 proceeding, continued his participation as an intervenor that time. The Council staff and the Attorney General then entered into the first discovery phase of the proceeding which lasted until April 1, 1981. At that time, both the Hearings Officer and principle staff analyst had left the employ of the Council; and, the Companies filed their Second Long Range Forecast on April 1, 1981.

Upon a review of the case, the present Hearings Officer elected to combine the on-going review with the review of the Second Long Range Forecast, limiting further discovery and review to new issues raised by changes in the most recent forecast. An Order of Notice was issued on May 22, 1981, setting June 12, 1981 as a deadline for intervention in the consolidated proceeding. By that date, two parties, the

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3 We note that the Companies must file a similar forecast in Connecticut and, cannot always be flexible to the Council's needs.

Conservation Law Foundation of New England, Inc. ("CLF") and the Franklin and Berkshire Community Action Programs ("CAPs") filed for intervenor status. The Hearings Officer set a date of June 24th as a Motions Session to address: Motions to Intervene; a hearings schedule; and, the scope of the proceedings.

At that hearing, arguments were heard on all issues and the Motions to Intervene allowed without objection. On July 9th, 1981, the Hearings Officer issued a Memorandum and Order which: defined the scope of the proceedings; allowed for the severance of "demand-side" and "supply side" hearings and allowed both Motions to Intervene. That Memorandum and Order is attached hereto as Appendix "B" (see: 6 DOMSC p. 201 (1982)).

Information requests and answers were filed by all parties, the Companies filed pre-filed testimony on August 14th, 1981 and a hearing on "demand side" issues was conducted on Wednesday, August 19th, 1981. The Companies presented two witnesses at that time: Charles Foncaioli, Manager of Economic and Load Forecasting, and Bruce Blakey, Supervisor of Load Forecasting.

Pursuant to a bench Order issued at that hearing, parties submitted discovery requests on "supply-side" issues by October 23rd, 1981. Both CAPs and CLF then filed Motions to Compel more direct and complete answers to discovery questions, CAPs by November 25th, and having been granted an extension of time, CLF on December 8th, 1981. On December 15th, 1981, the Companies filed an Answer to the Motions to Compel. On December 16th, 1981, the Hearing Officer issued a lengthy Memorandum and Order attached here to as Appendix "C", directing the Company to respond fully to questions concerning their on-going construction and oil back-out programs, thus granting all intervenor motions.

The Companies further objected to CLF Question "Q-8", submitting that the document requested by CLF did not exist and, therefore, was not an existing document which they could be compelled to produce. CLF again filed a Motion to Compel on January 13th and the Companies responded on January 21st, 1982. The Hearing Officer sustained the Companies' objections on February 24th, 1982. On March 16, 1982, CLF filed an Objection to that Order and a Petition for Rehearing. That Objection and Petition were denied by Order on March 22nd, 1982, as it was concluded that CLF had asked for a document which was not within the "possession, custody or control" of the Companies. M.R. Civ. Pro. 34.

By Procedural Order dated March 23rd, 1982, hearings were set for April 20th and 21st, 1982, on "supply-side" issues. On April 16th, 1982, CLF moved to withdraw from the proceeding. The Motion was allowed, for reasons other than those covered in the Motion, by Order dated April 20th, 1982.

During the hearings held at the Council Offices on April 20th, the Company presented the following witnesses: Mr. Roy Norman, Director of Energy Management Services; Mr. Norman Rutty, Senior Research Analyst in the Consumer Research Department; Mr. Richard H. Brown, Director of Consumer Economics and Mr. Frank Sabatino, Manager of Generations Planning. As a result of issues raised at the hearing, a number of record requests were allowed, both on behalf of EFSC staff and CAPs. The record was closed on May 7th, 1982.

III. SCOPE OF REVIEW

The Council has the jurisdiction to review, evaluate and issue decisions on company long-range forecasts, and to permit new facilities and therefore supplies to be added to the individual systems. To do this, the Council exercises broad discretion in scrutinizing the forecasts and forecast assumptions that serve as a basis for the Company's decision making process. Although this standard applies most apparently in cases wherein a new facility is proposed, the Council must always be prudent in determining whether new facilities are, in fact, the least cost alternatives actually needed.

The Long Range Forecast submitted by the Companies must be measured against the requirements set forth in section 69J of Chapter 164 of the General Laws. That provision lays down a broad guideline for electric company forecasts, mandating that each five year forecast accurately project "... the electric power needs and requirements of its market area, taking into account wholesale bulk power sales or purchases and other cooperative agreements with other electric companies, for the ensuing ten year period."

Consistent with our general mandate, that is, to ensure "... a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost", MGL Ch. 164 secs. 69H, 69J, we focus our review on the adequacy, reliability (e.g., diversity and redundancy) and cost of supply necessary to meet projected demand. To do this we look at four distinct areas of the Companies' forecast and system plan for the ten-year forecast period.

We must consider the electric companies' forecast of demand for their product within their "market area" MGL Ch. 164 sec. 69I. This forecast of demand must consider not only the growth or decline of aggregate demand by residential, commercial and industrial customers within the Companies' normal market area but also must take, "into account wholesale bulk power... sales or purchases or other cooperative arrangements with other utilities and energy policies as adopted by the Commonwealth." MGL Ch. 164 sec. 69I(2). Such agreements may be sales or purchases of capacity or energy to or from other sources, whether short term or life of unit contracts, the New England Power Pool agreement, and other commitments to provide electric service to wholesale customers over the forecast period.

The second area into which we must look is the adequacy of the Companies' supply plan. This is to focus on, "... actions planned to be taken by the Company which will <u>affect</u> capacity to meet such needs or requirements, including, but not limited to: expansion, reduction or removal of existing facilities; construction or acquisition of additional facilities; a description of alternative to planned action such as other methods of generating, manufacturing... provided, however, that the above provisions shall not apply to facilities which have been approved as part of a previous long-range forecast or supplement thereto." MGL Ch. 164 sec. 69I(3) (emphasis supplied). In the instant case, as will be discussed in part VI infra., we will see that the Companies have planned a number of "actions" which will affect the capacity to meet needs or requirements through their oil back-out program, <u>N.U. Program for the 80's and 90's</u>, other actions by companies which might affect the accuracy of projected on line dates for capacity additions and actions which will defer plant retirements, such as coal conversion.[4]

Thirdly, we must look to another aspect of adequacy of supply. Rather than aggregate capacity to provide necessary energy as discussed above, we must here look to the diversity of the system's fuel mix to assure that sudden interruptions of a particular fuel, i.e. oil, or plant i.e., nuclear, would not unduly impede the companies' ability to provide reliable power adequate to meet forecast demand. MGL Ch. 164 secs. 69H, 69J. Again these issues are discussed and reviewed in part VI infra.

Lastly, we are required to assure that the supply plan provides for an adequate supply of energy at the least possible cost. MGL Ch. 164 sec. 69H, 69J. In order to do this we must be able to analyze "actions planned by the Company(ies)" in order to determine the relative costs and benefits of each action. Certainly, the actions which the Companies will take to extend plant life, diversity their fuel mix, and reduce dependence on oil are important activities in this regard.

To the extent such activities defer additional new plant construction, they further the Council's mandate to assure "an adequate supply of energy with a minimum impact on the environment MGL Ch. 164 secs. 69H, 69J.

The Council will continue to exercise this extensive and thorough review consistent with its public mandate. Such thorough investigative actions are necessary to the review process and the authority to do so may be necessarily or reasonably inferred from the Council's enabling

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4 We do not, however, confuse our duty to pass on the adequacy of a supply plan to meet forecast demand with jurisdiction to approve or disapprove the companies' management decisions as to planned capacity and transmission additions. MGL Ch. 164 sec. 69I, J.

legislature, Chapter 164 sections 69H et seq.; In Re Boston Gas Co. et al. in 7 DOMSC ___, EFSC No. 81-25 (1982). See: Grocery Manufacturers of America et al. v. Department of Public Health 393 N.E. 2d 881, 886-887, 1979 Mass. Adv. Sh. ___; Levy v. Board of Registration and Discipline in Medicine 1979 Mass. Adv. Sh. 1857, 1862, 392 N.E. 2d 1036 (1979): Opinion of the Justices 368 Mass. 381, 834-835, 33 N.E. 2d 368 (1975). Recourse to specific authorization is wholly unnecessary as such powers are shaped by the "organic statute taken as a whole." Grocers Mfrs. supra, at 886; Commonwealth v. Cerveny 1977 Mass. Adv. Sh. 1943, 1952, 367 N.E. 2d 802, 808 (1977). The Council must take such action because it is "... responsible for implementing the energy policies..." in its organic statute, and must seek "... to provide a necessary energy supply for the Commonwealth...". Further, the Council is empowered to ensure that necessary supplies energy are provided customers in the Commonwealth, "... at the lowest possible cost." MGL Ch. 164 sec. 69H.

IV STANDARD OF REVIEW

In determining whether the Companies' forecast meets the requirements of section 69H, the Council must apply the standards set forth in section 69J. That is, the Council shall approve the forecast, if it determines that:

(1) "... all information relating to current activities, environmental impact, facilities agreements and energy policies as adopted by the Commonwealth is substantially accurate and complete;

(2) projections of demand for electric power ... and of the capacities for existing and proposed facilities are based on

substantially accurate historical information and reasonable statistical projection methods;

(3) ... projections relating to service area, facility use and pooling or sharing arrangements are consistent with such forecasts of such companies subject to this chapter... and reasonable projections and activities of other companies in the New England area..."; and finally,

(4) that the forecast is, "... consistent with the policies stated in section 69H 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. 69J.

Although other criteria will apply, in addition, to a proposed facility, these four standards apply in this case. With these criteria in hand, we now will review the Second Long-Range Forecast of Electric Needs and Requirements filed by the Northeast Utilities Companies.

V. REVIEW OF DEMAND FORECAST AND FORECASTING METHODOLOGY

A. Introduction and Review of Past Forecasts and Forecast Supplements

The development of NU's demand methodology has been a dynamic process. Since 1976, the Companies have consistently improved their methodology and data collection efforts, often in line with state-of-the-art developments. While room for improvement always remains, the Companies' Forecast methodology is quite progressive and, in recognition of this fact, the Council's review of NU's demand model will primarily focus on incremental improvements in the Forecast, with particular emphasis on the development and integration of econometric sub-models.

The Council employs three criteria in its evaluation of electric company demand forecasts. A forecast is reviewable if a company's submission to the Council contains enough information to allow a full understanding of the company's methodology. Once this threshold of documentation has been passed, the Council examines whether a forecast is appropriate, or technically suitable for the utility at hand. A forecast is further judged reliable if it provides confidence that the assumptions, judgements and data forecast what is most likely to occur. (EFSC Rules 69.2 and 66.5; Part IV, 1, 2, 3, 4 *supra*)

Table 1 summarizes the major conclusions of the entire forecasting effort by the company.

The remainder of this introductory section briefly reviews the development of the Companies' methodology since the original filing in 1976. A review of the Northeast Utilities forecast methodology must be made within the context of the progress the company had made since its

Table 1

Northeast Utilities Companies

Principal Results of NU System Forecast

	Actual 1980	Forecast 1990	Compound Growth Rates 1980-1990 (%)
Residential Class			
Average Number of Customers	977,496	1,127,444	1.4
Average Use per Customer (kWh/yr)	7,663	7,847	0.2
Total Sales (GWh)	7,491	88,847	1.7
Commercial Class Sales (GWh)	5,858	7,224	2.1
Industrial Class Sales (GWh)	5,230	6,062	1.5
Streetlighting Class Sales (GWh)	186	156	-1.7
Railroad Class Sales (GWh)	0	173	-
Total Retail Sales (GWh)	18,765	22,462	1.8
Wholesale for Resale Class Sales (GWh)*	1,064	1,002	-0.6
Total Sales (GWh)*	19,829	23,464	1.7
System Peak Load (MW)*	4,030**	4,856	1.9

* Sales and Peak Loads of participants in the Connecticut Municipal Electric Energy Cooperative (CMEEC) have been removed from 1980 data to more accurately reflect the relationship between actual and forecast. In previous forecasts the sales and peak loads of the Connecticut Municipal Customers were included in the NU forecast. With the formation of CMEEC, the Municipalities involved are no longer customers of NU.

** estimated

Source: 1980 Forecast, Volume 1, page iv.

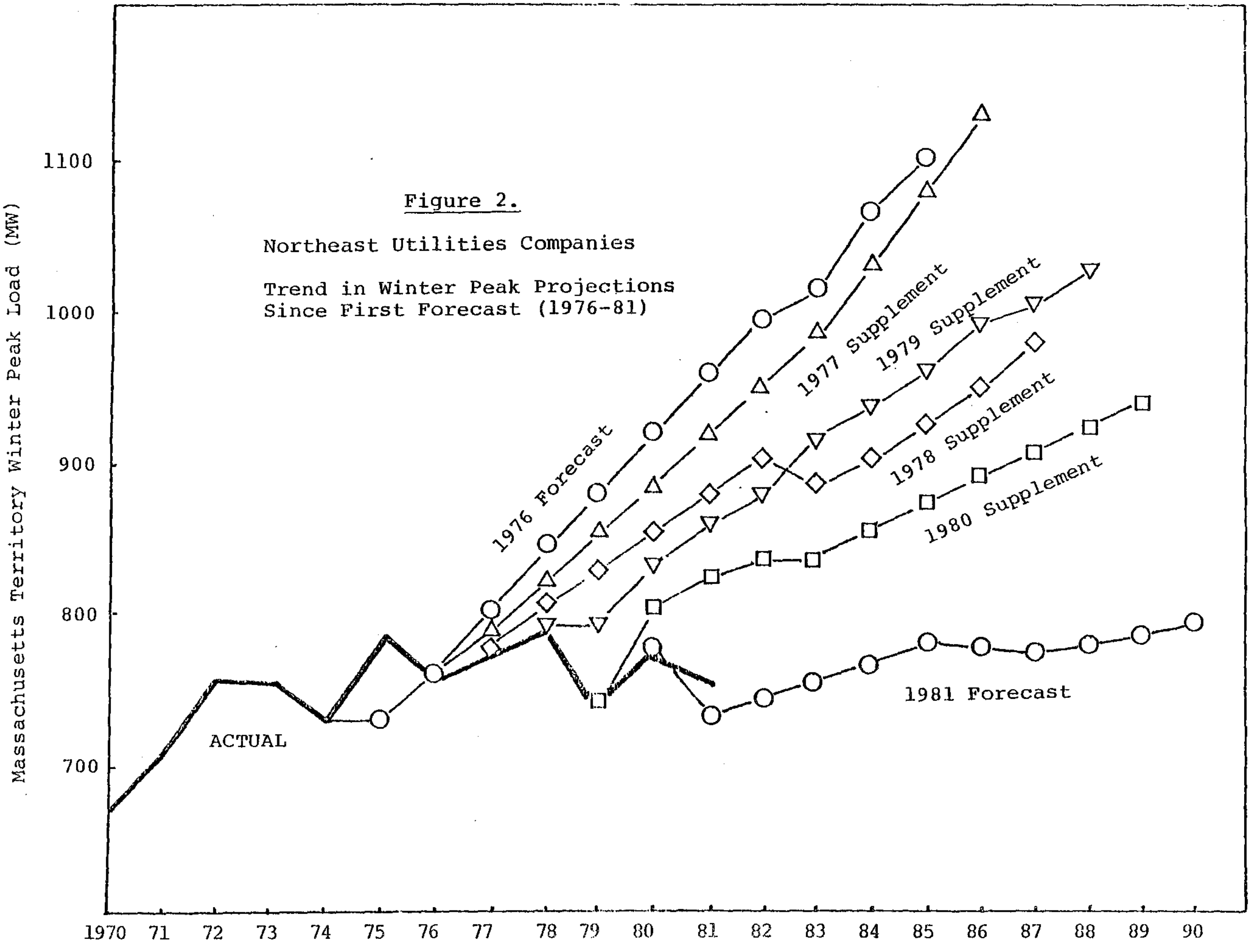

Figure 2.

Northeast Utilities Companies

Trend in Winter Peak Projections
Since First Forecast (1976-81)

initial filing with the Council on May 1, 1976. For that reason, the following should be treated as a summary of that progress. Figures 1 and 2 show in graphic form the energy and peak forecasts since 1976.

1. First Forecast (1976)

In the initial Forecast, total energy needs were disaggregated into customer classes: residential, commercial, industrial, wholesale sales, streetlighting, and railroad, as required by rule EFSC 63.7

The residential class forecast utilized an end-use model, employing a projection of the number of residential customers along with a projection of average electricity use.

The forecast of the number of residential customers utilized population growth assumptions for those groups aged 20 to 64. The population growth estimate was done by using the cohort survival method, which splits the population into cohorts, or subgroups of ages 20-24, 25-30, etc., and applies an average survival rate for each cohort taken from Connecticut data. This population forecast was then adjusted by use of the net migration rate as estimated for Connecticut by the Connecticut Department of Planning and Energy Policy. The migration projection for the Western Massachusetts service territory was based on a historical trend of negligible net migration which was assumed to continue.

The forecast of average electricity use per household was determined as the product of the projected number of appliances owned by the projected number of customers and the average electric energy consumed by each applioance. The following appliances were considered:

electric space heating; electric water heating; fossil fuel heating auxiliaries; electric range; central air conditioning; electric dryer; manual defrost refrigerator; automatic defrost refrigerator; color TV; lights; electric car; and, miscellaneous. The number of appliances was projected by using an estimate of the rate of penetration of each appliance by existing customers, new customers, and appliance replacement markets. These penetrations were founded on assumptions about the individual appliances. In addition, NU conducted a saturation survey which measured the extent of ownership of each particular appliance. From these projections, the total kilowatthour consumption of those numbers of appliances was determined and divided by the projected number of customers in order to determine the average kilowatthour use per customer. It should be noted that these appliance penetrations and saturations were determined using Connecticut data. NU used the projections obtained from this Connecticut data for both its Connecticut and Western Massachusetts service territories, using the assumption that those service areas are similar in most economic and demographic characteristics.

Turning to the commercial forecast, NU was in the process of reclassifying all commercial customers by three digit SIC (Standard Industrial Classification) code. The commercial sector is difficult to model due to the large number of customers which are of different sizes and types, and this classification system would allow the various customer types to by modelled individually. As this effort was still in progress, and NU only had access to data from 1974 on, statistically reliable modelling techniques were not possible. Instead, Connecticut

Energy Advisory Board projections of energy consumption in the commercial sector were used.

In the industrial forecast, as in the commercial forecast, NU was in the process of reclassifying its customers by three digit SIC code. In the meantime, the available data was disaggregated into 14 two digit SIC codes. The projection of industrial electricity consumption was based on the Data Resources, Inc. forecast of national production indices, based on the assumption that electricity usage in this sector is highly correlated to output.

Streetlighting sales were forecast as a continuation of the historical trend of an annual 2% growth.

Sales to railroads were projected by taking into account any future developments in this sector that might require electric power.

Wholesale sales were taken directly from the wholesale customer's own forecast of need.

Finally, as required by EFSC rule 63.6, an effort was made to forecast peak load. NU utilized recently gathered residential load test information, industrial metering data, and records kept for streetlighting, railroads and wholesale sales to determine the composition of the load. The remainder of the load was, by elimination, from the commercial sector.

This First Forecast was approved by the Council, subject to the following conditions:

(1) NU should document the coefficient for the relation of population to household.

(2) NU should develop empirical data for and an analysis of:

a) Price impact upon consumption

b) Load management impact upon consumption and peak

c) Use of modified national production indices for industrial demand forecasting

d) Use of Connecticut Energy Advisory Board methodology and projections for commercial demand forecasting[5]

These concerns were addressed by NU in subsequent forecasts, as noted below.

2. First Supplement (1977)

Several changes were instituted in the 1977 Supplement, submitted on December 30, 1976. The projection of the number of residential customers utilized the previous method of cohort survival modified by the addition of age-specific migration rates and also age-specific headship rates, to determine the number of heads of households. The residential sector forecast also took into account the mix of dwelling types, single family vs. multi family units (apartments). For the commercial sector, a simulation model was developed, which was disaggregatied into seven SIC divisions. The model projected sales as a product of an employment forecast and a forecast of kilowatthour consumption per employee. The basic model structure for the industrial forecast remained the same, although the equations were modified and respecified in some cases. The forecast of peak load introduced the use of time varying load factors. Finally, the entire forecast was run within both a base case and a high growth scenario.

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5 1 DOMSC 234 (1977).

Council review of this supplement was waived "given the withdrawal of the Companies' proposed nuclear power plant from regulatory review and in light of updated system-wide data in the 1978 Supplement."

3. Second Supplement (1978)

Significant changes were again undertaken in the 1978 Supplement, submitted by the Companies on December 30, 1977. An integrated economic/demographic model, adapted from the NEPOOL-BATELLE model, was developed. Within this model, migration was forecast as a function of the ratio between national and local unemployment rates. The commercial model employed a projection of commercial employment and developed a measure of square feet of commercial floor space per employee. This was used in conjunction with an econometric projection of potential energy use per employee in order to determine commercial demand.

The Council's decision on the Second Supplement sought to "praise the scope and sophistication of the Companies' work to date, but also to emphasize that the conceptual structure of many aspects of the various submodels are preliminary and in need of more, and more accurate, data." The forecast was approved subject to the following conditions:

(1) NU should follow the guidelines for forecast development and documentation as per EFSC Rules 69.2 and 69.3.

(2) NU is directed to implement substantive improvements to its Commercial class submodel.

(3) NU should consider the points raised by the Attorney General; NU's ongoing approach to the development of its methodology and database should resolve many of these issues.

(4) NU should measure the resilience of their forecasts to business cycle effects.[6]

4. Third Supplement (1979)

In the 1979 Supplement, submitted on April 2, 1979, the only major change was in the economic/demographic model, which replaced a cost index relating regional vs. national costs with trend analysis, due to a lack of complete data.

Although formal Council adjudication of the 1979 Supplement was suspended[7], the EFSC staff reviewed the filing and noted the following concerns:

(1) Using U.S. or Connecticut data to approximate service territory data

(2) The model development process which lead to the choice of regression equations, and the econometric documentation

(3) The assumption, in some cases, of the continuation of past trends

(4) The level of consistency of assumptions and individual variable forecasts[8]

5. Fourth Supplement (1980)

The 1980 Supplement, submitted April 1, 1980, incorporated the following changes: in the economic/demographic model, new migration equations were developed; and in the residential sector, the energy

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6 3 DOMSC 29, 33-35 (1978).

7 See Appendix A.

8 See: Staff Memorandum to Files, EFSC Docket, 80-17, 79-17.

efficiency of retrofitting was considered.

Council review of this forecast was deferred in anticipation of the Second Forecast.[9]

6. Second Forecast (1981)

The 1981 Forecast, submitted to the Council on April 1, 1981, includes some dramatic changes, most notably the addition of econometric models in the residential and commercial models for short run forecasting, and the ARIMA forecast of residential electric customers. Other changes are as follows: In the economic/demographic model, migration is estimated in aggregate as a function of relative per capita income and time. In the commercial model, consumption is analyzed on a per employee basis rather than using square footage estimates. The industrial model is no longer disaggregated due to data problems. Finally, the new NU Conservation Program for the 80's/90's is a significant source of new assumptions and modifications to the demand forecast. These changes shall be discussed in detail in the following analysis.

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9 See Appendix B.

B. Economic/Demographic Sub-model

The economic/demographic module provides service territory-specific estimates of employment and population which serve as important inputs to models of residential, commercial, and industrial demand.

1. Demographics

To forecast service territory population, the model uses the cohort-survival method, where aggregate migration of the working age population is estimated as a function of relative per-capita income and time. The Companies refer the reviewer to the 1980 Supplement for documentation of the population algorithm used to compute births, aging, and survival, stating that a standard demographic technique was utilized. Forecast births are added to the population surviving from the previous year, and forecast net migration is added or subtracted as necessary. The model has an income component consisting of state personal income (real and nominal) and per capita income (1972 dollars). Personal income is calculated as a portion of national income and is forecast as a function of employment share.

Migration rates for migrating children (cohorts of age 0-14) are estimated as a function of women by age and by the probability of their having children within this age group. Migration rates for cohorts greater than 59 were taken from a University of Georgia study entitled, Net Migration of the Population, 1960-1979 by Age, Sex and Color, Part 1 Northeastern States. Zero net migration is assumed for the WMECo service territory. The Companies forecast population growth at an annual rate of .50%; this growth rate is lower than that forecast for Connecticut (.61%) due to the zero net migration assumption.

As the population forecast is an important component of the separate sales models, the Council would like to see additional documentation, particularly with regard to the cohort equations used for births, aging and survival. The Company is reminded that Council staff, intervenors and interested parties change over the years, and that sufficient documentation should be self-contained in each annual filing, without needing to reference past submissions.

2. Employment

The Employment Forecast is driven by DRI's national economic forecast, with modifications to incorporate the specific characteristics of NU's service territory. Manufacturing employment is estimated as a function of national employment and time with SIC specific equations; for all SIC's except 20 and 27[10], non-manufacturing employment is also forecast by SIC as a function of national employment to population ratio. A service area forecast is driven by variables from the Connecticut forecast including individual growth rates by SIC. The employment mix is adjusted to reflect the conditions of WMECo's service territory.

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10 In these SIC's 20 and 27, food & printing, local population and employment are forecast as independent variables.

C. Price Forecast

The price of electricity is a primary variable in each of the sectoral submodels. Accurate price information is particularly critical in the commercial and industrial econometric models, where marginal price is used.

Historic price information is based on NU's rate schedules by operating company. As the Forecast was prepared in 1980, 1980 prices were estimated by the Rate Department, taking into account the impact of fuel adjustment charges. Prices for 1981 and the future were calculated by the Capacity Planning Department, using DRI projections for fuel costs. The projections of the Capacity Planning Department were "based on various factors including generation mix, fuel costs using DRI projections, plant maintenance schedules and rate-of-return. These annual escalation factors were applied to the 1980 price estimates to produce forecast electricity prices."[11]

Given the importance of price in the sectoral sales forecasts, the lack of documentation for the price forecast is a source of concern. This issue had been a source of contention between the Companies and the Attorney General in previous years. Paul Chernick, in testimony for the Attorney General, stated, "A forecast which is significantly sensitive to electric price is only as reliable and reviewable as the price

11 Forecast, p. 4.
12 Testimony of Paul L. Chernick on behalf of the Attorney General, EFSC 80-17, March 12, 1981, p. 26.

forecast which drives it."[12] The A.G. requested that the Companies provide, "descriptions of the models used (such as would be provided in a user's manual, for example), backcasts and calibration checks, and projections of important input values.[13] The Companies have responded that the analysis underlying the forecast is far too complex to be documented in the forecast and have indicated a willingness to provide any interested party with available documentation through a Technical Session[14].

The Council appreciates the Companies cooperation in providing information not available in the forecast to the Staff during Technical Sessions. However, in light of the importance of the price forecast to the forecast as a whole and the role of accurate, current fuel price assumptions to the price forecast, the Council would like to see expanded documentation.[15] This would include fuel price assumptions incorporated into forecast documentation in the interest of reviewability. A description of any simplying assumptions, such as constant heat rates, or planned coal conversions, should be listed as well.

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13 Id.

14 Prepared Testimony of Charles J. Roncaioli, August 19, 1981, page 10.

15 See In Re Boston Edison Company, 7 DOMSC _____, EFSC No. 80-12 at p. 30 (1982).

D. Residential Sector Sub-Models

Residential consumption forms approximately one third of N.U.'s total electric sales. NU projects a compound growth rate of 1.7% for this class from the 1980 level of 7,491 GWh to the 1990 forecast level of 8,847 GWh.[16]

Residential energy consumption can be viewed as a function of a number of customer decisions: the choice of appliances to be owned; technological characteristics including type of fuel utilized; embodied in these appliances; and, amount of usage. Further, these decisions depend upon fuel prices, demographic trends and socio-economic characteristics of the consumer.

NU's sales forecast is based upon the results of both an econometric and an end-use model.[17] The econometric model's purpose is to forecast short-run residential consumption and allows for explicit treatment of price effects, while the end-use model forecasts long-run consumption and takes into account factors including appliance efficiency standards and the impact of programs such as NU 80's/90's conservation plan.

1. Residential Econometric Model

NU estimated residential sales with a semi-logarithmic function of customers and an interaction price term. The semilog transformation is

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16 Notwithstanding the Companies' announced efforts to control overall system growth to within 1.5% as a part of its Conservation Program for the 1980's and 1990's.

17 See Forecast p.3, Vol. 1, and "Modelling Boston Edison's Commercial Sector Energy Demand", EFSC memorandum, Jan. 21, 1982. The coefficient on the price term in such a model is typically called an elasticity. Estimation and treatment of elasticity in the forecasting effort is critically important given the volatility of electric prices. The importance of elasticity is further developed and discussed infra., in Section H.

Table 2

Northeast Utilities Companies

Northeast Utilities' Forecasting Models for Electricity Sales to the Residential Sector

Short-Run Econometric Model

$$\text{Residential Sales}_t = B_o + B_1[\text{log. no. of res.elec. customers}_t] + B_2[\text{log. interaction price term}_t]$$

where:
t = time period
B_o, B_1, B_2 are the parameters to be estimated in the regression analysis

Long-Run End-Use Model

$$\text{Residential Sales} = \sum_{i=1}^{I} \text{Sales}(i)$$

where:
Sales(i) = sales to the residential sector for end-use i, as defined below
I = total number of end-uses

$$\text{Sales}(i) = \sum_{t=1}^{T} \text{CUST}_t \times \text{UNIT}(i)_t \times \text{USE}(i)_t$$

where:
CUST_t = forecast of number of residential customers in period t
$\text{UNIT}(i)_t$ = forecast of number of appliance units per customer for end-use i in period t
$\text{USE}(i)_t$ = forecast of average electricity use per appliance unit for end-use i in period t
t = time period
T = final time period

often used in building models which involve rates of growth. The growth rate is assumed at a constant annual rate with some variation to account for various random events. Relationships are hypothesized and logs are used to transform the relationship into a linear form, which is necessary for the statistically reliable estimation of the model.

The Companies chose to use estimated sales as opposed to use per customers in order to include customers as an independent variable, permitting measurement of changes in usage patterns.

The Companies initially attempted to develop a partial adjustment specification model. However, the Statistical Analysis System (SAS), NU's computer package, does not have the capability to correct the serial correlation errors and biased co-efficients resulting from the inclusion of lagged dependent variables. Thus, this attempt was unfortunately dropped.

As NU states "Conventional demand theory includes income within the demand function".[18] However, NU encountered serious multicollinearity problems using income as a variable and subsequently dropped the variable.[19] While dropping a variable is one correction for multicollinearity, the Companies are encouraged to look at alternatives such as formalizing the relationship between regressors.

The Companies eventually selected a model which regresses sales on customers and an interaction price term. NU describes the basis for the interaction price term as follows: "It is hypothesized that individuals

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18 Forecast, Vol. 1, p. 13.

19 Regression theory is based upon the premise that there is no exact linear relationship between independent variables. In the case where such a linear relationship does exist, multicollinearity is a problem that may lead to inaccurate interpretation of the coefficients.

are more aware of their total bill than the [marginal] price per kWh and this concept would pick up consumer price decisions more readily. Second, the interaction part of the price term allows for changes in the oil price index to explain movements in the coefficient of the real electric bill."[20] As of 1980, 10% of NU's customers had all electric heat. The Companies theorize that since the majority of its residential customers use fossil fuel for electric heat, they are sensitive to fossil fuel prices and will respond to increased price by decreasing electricity use as well as heating fuel use, indicating that the cross elasticity between fuel oil and electricity is relatively elastic.

While the Companies feel satisfied with defining the parameter on the price of electricity as a function of the price of oil, the Council encourages the Companies to attempt to model the price of electricity, both marginal and average, for the price interaction term.[21]

2. Residential End-Use Model

The residential end-use model forecasts sales for seventeen appliance categories[22], disaggregated by operating company and between single and multifamily housing units. Essentially, the model, in NU's words, "can be thought of as the product of the number of appliances and the use per appliance summed across the sixteen appliance types and miscellaneous"[23].

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20 See discussion on elasticities, infra. at part V(H).

21 Forecast, p. 13, Vol. 1.

22 Electric space heating systems, electric pump heating systems, electric assisted renewable resource space heating system, electric water heating, electric assisted renewable resource water heating system, fossil fuel heating auxilaries, central air conditioner, room air conditioner, electric range, electric dryer, manual defrosting refrigerator, freezer, color television, lighting, electric car and miscellaneous.

23 Forecast, p. 14, Vol. 1.

The appliance model is initialized to the level of sales and appliance stock as estimated in 1980. Growth is forecast based on expected growth in absolute number of appliances and expected levels of usage for those appliances.

The 1980 stock was determined from the Companies' records of the number of electric heating customers and from the 1980 Appliance Saturation Survey which established ownership percentages by building type. Percentages derived from the saturation survey were then applied to estimates of customer by type of housing structure.

Incremental units of new appliances are calculated by applying market penetration percentages into markets for new housing, replacement and existing markets.

The new housing market consists of all newly constructed houses in any given year. It is based upon historical percentage distribution of building permits by housing type in NU's various service territories. NU states, "the potential consumption of this market per household is great because of the opportunity for these households to acquire electric heating systems and other electrical appliances." NU has found average annual use per new appliance to be lower than that of initial stock, as would be expected.

The Companies are advised to continually monitor and study trends in new housing, such as the number of new appliances per home, and impacts of new technology. This is of particular importance in the case of heat pumps. While the heat pump is an efficient appliance, it also provides the customer with a central air conditioning system that he may not have had before, potentially leading to increased electric demand.

NU believes that the penetration of electric heat is on the rise, forecasting that penetration of electric resistance space heat, electric heat pumps and renewable resource space heat units combined will increase from 25% in 1981 to 45% in 1990 for single family units and from 35% in 1981 to 55% in 1990 for multi-family units. Given NU's forecast for a substantial increase in the heat pump saturation over the forecast period (see Table 3), the load implications of heat pump use are worth studying, in the context of both new and existing markets.

3. Conservation Assumptions in the End-Use Model

The Companies recognize that the proposed DOE mandatory appliance efficiency standards may be replaced by voluntary industry standards. Therefore, they assume three sets of interim standards. The first of these would be effective in 1983, the second in 1989 and finally the maximum technologically feasible level in 1997.

Similarly, the Companies acknowledge doubt as to whether proposed DOE Building Energy performance standards for new construction will become mandatory. However, the forecast presumes standards equal to NU's NEW program standards after 1985. The Companies forecast a decline in space heating requirements for existing single family homes from 16,500 kWh in 1980 to 15,300 kWh. This assumption is based on expected impact of CONN SAVE; MASS SAVE and other information and action programs. Conservation from wrapping and turning down electric water heaters, through NU's programs, is expected to reduce average water heater consumption by 5% by 1985.

The Council approves of NU's efforts to encourage conservation and its attempts to model its impacts. The Companies are encouraged to gather as much data as possible on the impact of implementation of

Table 3

Northeast Utilities Companies

Heat Pumps: Number of Units and Percent Saturation

	Heat Pump	Saturation %
	SINGLE FAMILY DWELLING	
1981	1583	0.3
1982	2250	0.4
1983	3103	0.5
1984	4446	0.7
1985	5957	0.9
1986	7736	1.2
1987	9691	1.5
1988	11835	1.8
1989	14233	2.1
1990	16821	2.5
	MULTI-FAMILY DWELLING	
1981	3634	0.9
1982	4570	1.2
1983	5699	1.4
1984	7024	1.7
1985	8539	2.1
1986	10236	2.5
1987	12115	2.9
1988	14186	3.3
1989	16443	3.8
1990	18886	4.3

Source: Forecast, Table R-7, Vol. 1.

conservation measures in order to verify that such assumptions as made in the forecast are indeed accurate. This issue will be developed further, infra.

4. Merging Econometric & End-Use Models

The econometric model, designed as a complement to the end-use model, adds reliability to the residential forecast for the short run. The econometric model was used until sales equalled those forecast by the end-use model; for WMECo, this point occurred in 1983. At that point, the transition to the end use model was made. Had use of the econometric model continued, the forecast would have been 8.0% greater.

The Council endorses the Companies highly practical use of both econometric and end-use approaches for forecasting sales to the important residential sector. The Council encourages the Companies to experiment with a long-run econometric model which would allow estimation of long-run elasticities. (See infra., Section (H).)

E. Commercial Sector Sub-Models

1. Introduction

The commercial sector is a diverse group of customers which includes schools, hospitals, offices, churches, and wholesale and retail trades. The electrical end-use characteristics of each subsector vary widely; thus the commercial sector is far from homogenous. This diversity, along with a lack of high quality, disaggregated data, has historically made it difficult to effectively model this sector.

In the past, NU relied on an end-use model driven by a forecast of non-manufacturing employment as estimated by the economic/demographic module. The three primary end-uses were heating, cooling and other uses. The sector was divided by stores (wholesale and retail trade) and offices (all other use).

In the 1981 Forecast, NU developed an econometric model to forecast short-run consumption. This model is used in conjunction with a modification of the long-run, end-use model, as was also done with the residential sector forecast.

2. Commercial Sector Econometric Model

NU developed an econometric model in order to be able to consider short-run economic conditions and electricity price effects.[24] This type of model cannot, however, effectively address long run changes such as building efficiency standards. This explains the model's best usage for short-run forecasting.

The model uses a semilog specification which forecasts electricity sales to the commercial sector as a function of residential customers

24 The importance of the price of electricity is further developed in Section H.

and electricity prices. The price variable represents the marginal price of electricity, using the block where the mojority of commercial customers would be paying. The model as it presently stands needs to be developed further. A more careful evaluation of the variables included and omitted must be made. The cost of labor and the cost of alternate fuels are examples of variables that may be very relevant to this analysis.

3. Commercial Sector End-Use Model

NU has improved upon its old end-use model for long-run commercial sector forecasting. The changes include: analysis of consumption on a per employee basis rather than square footage of commercial floor space; an econometric forecast of growth in potential energy use per employee; and disaggregation of the forecast of penetration of electricity into heating, cooling, lighting and other applications. These are useful modifications to the previous model. However, the basic structure of the model, with the commercial class characterized as "stores" or "offices" and the end-uses of heating, cooling and other, needs to be improved. Disaggregation by 2 or 3 digit SIC code where appropriate might allow more effective analysis of the growth trends within the sector. Additional end-uses should be more explicitly modeled or it should be demonstrated that the stated degree of disaggregation is adequate.

4. Conclusion: Commercial Sector Forecast

The short-run econometric model is a welcome addition to the commercial sector forecast, particularly as it can explicitly treat the effects of changing electricity prices. The Council encourages the Companies to further develop both the econometric and end-use models to

Table 4

Northeast Utilities Companies

Northeast Utilities' Forecasting Models for Electricity Sales to the Commercial Sector

Short-Run Econometric Model

$$\text{Commercial Sales}_t = B_o + B_1[\text{log. no. of res. elec. customers}_t] + B_2[\text{log. elec. price}_t]$$

where:
- t = time period
- B_o, B_1, B_2 are the parameters to be estimated in the regression analysis

Long-Run End-Use Model

$$\text{Commercial Sales} = \sum_{i=1}^{I} \text{Sales}(i)$$

where:
- Sales(i) = sales to the commercial sector for end-use i, as defined below.
- I = total number of end-uses

$$\text{Sales}(i) = \sum_{t=1}^{T} \text{EMP}_t \times \text{ENERGY}(i)_t \times \text{ELEC}(i)_t$$

where:
- EMP_t = forecast of commercial employment in period t
- $\text{ENERGY}(i)_t$ = forecast of potential energy use per employee for end-use i in period t
- $\text{ELEC}(i)_t$ = forecast of electricity's share of total energy needed for each end-use i in period t
- t = time period
- T = final time period

better capture the diversity of this sector. The fact that the Companies anticipate the greatest growth to occur in this sector makes this all the more important.

F. Industrial Sector Forecast & Methodology

The industrial sales class consists of manufacturing and process plants and manufacturing offices. The industrial class has traditionally been the most vulnerable sector to economic fluctuations.

In the past, NU had built the industrial sales forecast from a series of equations for the major SIC categories. Variables used in these econometric models included national production indices, national employment, local employment, and time trend (See Table 5A).

NU's current model uses a single equation, by individual operating company, for total industrial sales. NU reverted to this aggregate model because "dramatic change occurred in the level of recorded sales by SIC due to the codification of accounts that accompanied the creation of the SIC data base described last year. These changes made time series or econometric analysis by SIC impossible".[25] (See Table 5B.)

The current model uses a semilog equation in which sales are a function of the price of electricity[26] and a production index. To make the production index both state and service area specific, national production indices by SIC were modified by state employment data. Next, these figures were weighted with a three year average of NU SIC electric sales data to reflect individual SIC contributions to total industrial electric sales. The price variable was based on the marginal price of electricity, using the block where the majority of industrial consumption would occur.

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25 Forecast, p. 17, Vol. 1.

26 The importance of this variable is further developed in Section (H).

Table 5A

Northeast Utilities Companies

Northeast Utilities' 1979 Forecasting Model for Electricity Sales to the Industrial Sector

Econometric Model, by individual SIC class -- Selected Disaggregate Equations

SIC 35 Non-Electric Machinery

	constant		Q x ratio of Conn to Nat'l Emp.		Interaction terms (conservation effect)		price of electricity		wage price
Sales =	9.21871	+	.477065	+	-.0155398	+	-.137143	+	.115431
	(8.08496)		(3.40861)		(-2.83475)		(-1.10543)		(.363276)

$\bar{R}^2 = .828$ Durbin Watson = 2.051

SIC 32 Stone and Clay

	constant	Federal Reserve Index of Industrial Production	Dummy
Sales =	8.51354	.609572	-.0815064
	(7.26227)	(2.51037)	(-1.28037)

$\bar{R}^2 = .795$ Durbin Watson = 1.285

NOTE: The values in parentheses under each coefficient are the t-statistics, which serve as a measure of the significance of the relationship between the dependent variable and an independent variable.

Source: Northeast Utilities Long Range Forecast, Volume I, April 2, 1979, Table I - 1.

Table 5B

Northeast Utilities Companies

Northeast Utilities' Current Forecasting Model for Electricity Sales to the Industrial Sector

Econometric Model*

$$\text{Industrial Sales}_t = B_o + B_1[\text{log. elec. price}_t] + B_2[\text{log. prod.index}_t]$$

where:
t = time period
B_o, B_1, B_2 are the parameters to be estimated in the regression analysis

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* Note: The model is estimated separately for each distribution company.

In lieu of the end-use models utilized in the residential and commercial sectors to treat conservation measures, the Companies incorporate a judgemental deduction into the industrial sub-model. After 1982, annual forecast sales levels are reduced by increments of 0.5 percent. Overall, non-price induced conservation results in a 4% reduction in the 1990 industrial sales forecast[27]. This year the Companies made a decision to view cogeneration as supply, hence its effects are no longer considered in the demand forecast.

Annual industrial sales, disaggregated by SIC and operating company serve as an input to the hourly load model (See infra). As sales are forecast in the aggregate it was necessary for NU to develop a method to allocate overall sales to individual SIC's. The Companies allocated sales on the basis of employment forecast outputs from the economic/demographic model and sales recorded by SIC. This method was based on the assumption that 1979 kWh use/employee would remain constant and change in SIC shares of total sales would change proportionately with relative growth in employment by SIC. The Companies point out the fact that whatever the breakdown of SIC's may be, the sum will always be the equivalent of the original total.

The aggregate econometric model selected by NU presents certain problems. The model does not account for varying levels of energy intensity and price elasticity across industries and is unable to deal with changes in the composition of industrial structure over time. On

27 It is often argued that all conservation efforts are ultimately price induced. An example of "non-price induced conservation" might be a choice to diversify fuel mix not to reduce costs but to reduce risk associated with an interruption in supply. Of course, this could also be considered a "price induced" decision if one discounts to the present the future costs of a possible interruption.

the other hand, disaggregated data is expensive and if individual SIC data is not accurate and complete, estimation of reliable model parameters may be extremely difficult. Given the previously mentioned vulnerability of the industrial sector to economic activity and the potential influence that either a recession or a boom may wield over the actual level of industrial sales, it is to NU's advantage to forecast this sector as accurately as possible. Recognizing the difficulties, time and expense inherent in building a good industrial data base, the Companies are nonetheless encouraged to study the feasibility of improving and reinstating the econometric model disaggregated by SIC codes which they have used in the past. The Council has recently suggested to another utility that all industries need not be fully disaggregated (at the 3-digit SIC level) if there is no substantive gain to the overall forecast.[28] The Companies might consider <u>supplementing</u> their aggregate industrial model with selected industry models (by 2 or 3 digit SIC levels where appropriate) for those industries whose demand is expected to be the most volatile over the forecast period.

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28 See: <u>In Re: Boston Edison 7</u> DOMSC ___, EFSC 80-12, (1982) at p. 46

G. Peak Load Forecast

1. Hourly Load Model

The Companies use an hourly load model to distribute the sectoral sales forecasts into an hourly demand forecast for electricity. Hourly load models are categorized by customer class and by operating company. Line losses and company use are factored into the hourly load forecasts.

The model requires large quantities of input data including the annual sales forecast, hourly demand factors, hourly load profiles, calender data pertaining to holidays, hourly temperatures and loss ratios.

The residential model was revised in the 1981 Forecast in order to reflect operation of the compressor and resistance heat components of heat pumps. In line with the previous discussion on load implications of heat pumps, supra., the Council is extremely pleased to see such refinements in the hourly load model.

2. Net System Energy Output Requirements

Hourly demands are added to hourly losses to arrive at hourly loads. The summation of hourly loads over a given period of time yields net system energy output requirements. Electrical energy output requirements are forecast to grow at a compound annual growth rate of 1.7%.

3. Peak Load Forecast

On the basis of the hourly load profiles, summer and winter peaks are identified. The model's forecasts summer peaks will occur from 1 to 2 p.m. or 5 to 6 p.m. Summer forecast peaks are expected to occur on a

Monday or Tuesday in August. Winter peaks are forecasted to occur between 5 and 6 p.m. or 6 to 7 p.m. on a Wednesday in December the companies expects the system peak to continue to occur in the winter, with the difference between winter and summer peaks increasing over the forecast period.

4. Normalization of Historic Peak and Historic Energy Output

Historic and forecast seasonal peaks and historic temperature were examined to analyze the relationship between demand and the temperature humidity index and daily mean temperature for summer and winter peaks, respectively. This was done with a regression equation to measure the sensitivity of peak loads to changes in daily mean temperature or THI.

5. Conclusion

The Companies forecast a compound annual growth rate of 1.9% for system peak load. The Company is to be commended on the strength of its peak load forecasting model, which is unquestionably the most sophisticated methodology of its kind in use by systems operating in the Commonwealth.

As mentioned, the Companies expect to see the gap between winter and summer peaks increase. The Companies are advised to investigate and analyze the factors causing the growing sensitivity of the winter peak to temperature. The Companies are also encouraged to further analyze and identify the specific factors causing peak load growth, and to consider using a range or band around peak projections to improve confidence in the forecast.

H. Demand Elasticities

In analyzing and projecting future electricity needs, a utility must consider all major factors which may influence consumer demand. The economic concept of elasticity of demand is one important element. There are three types of elasticity which affect electricity demand.

(1) Own-Price Elasticity of Demand: the ratio of the percentage change in the quantity demanded of a good per a percentage change in the price of that good. The demand for a good can be characterized by the absolute value of its price elasticity in three ways. If the absolute value is greater than one, demand is elastic, or relatively responsive to changes in price. If the absolute value is one, there is unitary elasticity. In this case, the percentage change in quantity demanded is the same as the percentage change in price. Lastly, if the absolute value of the elasticity is less than one, demand is inelastic, or relatively unresponsive to changes in price. Historically, it was thought that electricity fell into this last category of inelastic demand.[29]

The consideration of own-price elasticity is important to a utility for a number of reasons. First, the utility should be aware of the impact on demand of increasing prices due to fuel cost adjustments. As costs to consumers increase, there is downward pressure on demand in both the short and long-run. This must be taken into account when projecting demand. Second, there can be a substantial effect on demand due to the inclusion of the cost of a new facility in the rate base. Thus, ironically, building expensive, new capacity can

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29 See Table 6 for examples of sectoral price elasticity estimates drawn from the technical literature.

reduce or even eliminate the projected demand that the plant was built to satisfy if price elasticity is sufficiently elastic. Third, when conservation is promoted through various forms of utility assistance, it is essential to distinguish between price-induced effects on demand as opposed to effects on demand induced by the efforts of conservation programs. Only then can the results actually attributable to the conservation program be examined. Lastly, accurate estimates of price elasticity are essential for the study and development of alternative rate structures, for example, time-of-use rates.

2) Income Elasticity of Demand: the ratio of the percentage change in the quantity demanded of a good per a percentage change in the income of the consumers of that good.

This measure is of interest especially when considering the currently unstable economy. It is important to anticipate the possible impacts on demand given, as the case may be, a vast improvement or further degradation in the prevailing economic climate, which could result in a substantial increase or continued decrease in demand. Few utilities explicitly consider these so-called income effects on future demand.

3) Cross Elasticity of Demand: the ratio of the percentage change in the quantity demanded of a good per percentage change in the price of some other good. Other goods can be characterized as substitutes, complements, or independent. When considering electricity demand, cross elasticity of demand is of particular interest for examining the influence of competitive substitutes, such as natural gas or fuel oil.

This information can be usefully incorporated in forecasts for the penetration of electric heat, heat pumps, and other major appliances which can use substitute fuels.

Each type of elasticity is typically estimated using time series data in an econometric model. Elasticity is not an instant effect; there is a time element or lag involved. Given, for instance, a price increase in electricity, a consumer will at first lessen his or er usage through simple behavioral actions, e.g. turning off unnecessary lights. Overtime, however, the consumer may buy more efficient appliances or make capital improvements on his or her home. Thus one must consider both short-run elasticities and long-run elasticities. The long-run elasticity response of electricity constomers to the dramatic increases in price in 1973-74 is perhaps now making its full impact. The steady decline in demand growth that NU has experience since 1976, as shown in figures 1 and 2, attests to the combined effects of short and long-run price elasticities.

There are many problems with estimating elasticities empirically. It is difficult to construct a model that is both theoretically and statistically reliable. A report for the Electric Utilities Rate Design Stucy[30] summarizes the results of then-existing independent models (see Table 6) and concludes:

1. The price elasticity of demand for electricity, for all classes of consumers, is much larger in the long-run than in the short-run.

30 "A nationwide effort by the Electric PowerResearch Institute, the Edison Electric Institute, the American Public Power Association, and the Natural Rural Electric Cooperative Association for the National Association of Regulatory Utilities Commissioners."

Table 6

Northeast Utilities Companies

Summary of Electric Price Elasticity Estimates by Sector

Type of Demand and Research Team	Short-run	Long-run	Type of Price Analyzed
Residential			
Houthakker	- 0.89	NE	M
Fisher & Kaysen	- 0.15	0	A
Houthakker & Taylor	- 0.13	- 1.89	A
Wilson	NE	- 2.00	A
Mount, Chapman & Tyrrell	- 0.14	- 1.20	A
Anderson	NE	- 1.12	A
Lyman	(-0.90)		A
Houthakker, Verleger, Sheehan	- 0.90	- 1.02	M
Halvorsen	NE	- 1.33	A
Griffin	- 0.06	- 0.52	M
Tyrrell & Chern	NE	- 0.99	A
Nelson	NE	- 1.6	A
Berman & Grauband	0	- 1.0	A
Woods	NE	- 1.5	A
FEA	NE	- 0.77	A
Commercial			
Mount, Chapman & Tyrrell	- 0.17	- 1.36	A
Lyman	(-2.10)		A
Halvorsen	NE	- 0.944	A
Griffin	- 0.04	- 0.51	M
Tyrrell & Chern	NE	- 1.23	A
Woods	NE	- 1.0	A
FEA	NE	- 0.87	
Industrial			
Fisher & Kaysen	NE	- 1.25	A
Baxter & Ries	NE	- 1.50	A
Anderson	NE	- 1.94	A
Mount, Chapman & Tyrrell	- 0.22	- 1.82	A
Lyman	(-1.40)		A
Halvorsen	NE	- 2.37	A
Griffin	- 0.04	- 0.51	M
Tyrrell & Chern	NE	- 1.28	A
Woods	- 0.3	- 0.7	A
FEA	NE	- 0.33	A

NE - Not estimated
NA - Not available
A - Average Price
M - Marginal Price

Source: Electric Utility Rate Design Study. Elasticity of Demand: Topic 2, Prepared by Task Force No. 2, January 31, 1977, p. 12a.

2. The average long-run elasticity for all consumer classes appears to be greater than one, based on the average of the results of the studies. The average long-run elasticity for each class is approximately -1.3.
3. While not indicated in the summary table, many studies indicate the existence of long-run cross-elasticities with respect to other fuels, in the +0.1 to +0.3 range.
4. In spite of the existence of these estimated elasticity values, it should be clearly pointed out that their use for a particular utility could grossly misrepresent actual values. Elasticities are highly dependent on socio-economic and industry mix characteristics. Thus, while these results are good references, individual utilities should investigate their own custmers' response to price changes.

NU acknowledged the importance of understanding the impact of prices in its original 1976 Forecast filing with the Council. At that time, however, this impact was treated implicitly, through the use of long-term DRI macroeconomic projections which are based, in part, on energy prices. Also, NU made some assumptions regarding more careful and efficient consumer use of energy. The major deterrents cited by NU to estimating elasticities were the limited range of past price variation and difficulties in model specification and price forecasting. In the Council's decision on that Forecast, the Companies were urged to estimate empirically, the various price impacts on consumption.

The first such treatment of price projections was done in the 1980 Supplement. The econometric model for the industrial sector included

Table 7

Northeast Utilities Companies

Short-Run Price Elasticity

	Average Price			Marginal Price			Marginal Price			
	Residential			Commercial			Industrial			
	CL&P	HELCO	WMECO	CL&P	HELCO	WMECO	CL&P	HELCO	WMECO	HWP[1]
1980	-.13	-.14	-.12	-.19	-.21	-.35	-.07	-.09	-.06	NA
1981	-.13	-.14	-.12	-.19	-.21	-.35	-.07	-.09	-.06	
1982	-.13	-.14	-.12	-.18	-.21	-.35	-.07	-.09	-.06	
1983	-.13	-.13	-.11	-.17	-.20	-.34	-.06	-.09	-.06	
1984	-.12	-.13	-.11	-.17	-.20	-.33	-.06	-.09	-.06	
1985	-.12	-.13	-.11	-.16	-.19	-.31	-.06	-.09	-.06	
1986	-.12	-.12	-.10	-.15	-.18	-.30	-.06	-.08	-.05	
1987	-.12	-.12	-.10	-.15	-.18	-.29	-.06	-.08	-.05	
1988	-.11	-.12	-.10	-.15	-.17	-.28	-.06	-.08	-.05	
1989	-.11	-.12	-.10	-.14	-.17	-.27	-.06	-.08	-.05	
1990	-.11	-.12	-.10	-.14	-.16	-.26	-.05	-.08	-.05	

1. An econometric forecasting model was not developed for HWP.

J. Summary and Conclusion: Demand Forecast and Forecast Methodology

The Companies' demand methodology forecasts compound growth of 1.71% for residential customers, 2.11% for commercial customers, 1.51% for industrial customers, 1.71% for total sales, and a 1.91% increase in system peak load.

The Companies' forecasting methodology is clearly presented, generally well documented, and all judgements are adequately explained. NU has gone beyond the requirements of the regulations and presented a thoroughly reviewable forecast.

It is also the conclusion of the Council that the Companies' methodology is appropriate for its service territory.

I. Documentation

The Companies filing and supporting documentation are generally well written and useful in explaining the many changes made in the various components of the models. However, the documentation should be increased to make the models more fully represented. More should be written about sensitivity tests, especially concerning the use of forecasted electricity prices, and also any judgemental assumptions made. Documentation on the short-run econometric models also needs to be improved to fulfill EFSC requirements. A page should be added to each filing which would summarize the econometric model regression results and the relevant tests and statistics, eg. t and F tests, R^2, and Durbin Watson statistics. In order to control printing costs, and still provide necessary information for efficient review of the forecast, a separate memo or technical appendix should be produced which would present the various model specifications tested in the development of the econometric models, ie., the different combinations of explanatory variables used. This memo should include all relevant statistics for each specification, eg. t and F tests, R^2, etc. and any other tests performed on the data or models, eg. correlations, etc. Also included should be a detailed citation and explanation of the reasons for choosing the final model and rejecting other options. This information, presented in a brief and succinct report, would allow the Council staff to easily review the theoretical and statistical basis of the econometric models, and be confident that sufficient research and evaluation had been devoted to the specification of the best possible model.

J. Summary and Conclusion: Demand Forecast and Forecast Methodology

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The Companies' forecasting methodology is clearly presented, generally well documented, and all judgements are adequately explained. NU has gone beyond the requirements of the regulations and presented a thoroughly reviewable forecast.

It is also the conclusion of the Council that the Companies' methodology is appropriate for its service territory.

The reliability of the forecast effort is greatly enhanced by the addition of short-run sectoral models. Used in conjunction with the long-run end-use models, they combine the best forecasting features of each type of methodology. The forecasts and the forecast methodology are hereby APPROVED unconditionally.

The Companies are required to consider the suggestions outlined in the preceding pages, as follows:

1) Additional documentation of forecasts (p. 21).
2) Documentation of Price Forecast (pp. 22-23).
3) Refinement of Residential Econometric Model (pp. 26-27).
4) Monitor and study trends in new housing and appliance usage (p. 28) and heat pump usage (p. 29).
5) Consider use of a long-run econometric model in its residential model (p. 31).
6) Further develop the Commercial Econometric model. (p. 33).

7) Improve Commercial sector end-use model through further disaggregate of data. (p. 34).

8) Study the feasibility of disaggregating the date used to derive its industrial econometric model. (p. 40).

9) Further analyze and identify specific factor causing peak load growth. (p. 42).

10) To continue its efforts to develop models for estimating both short and long-run elasticities. (p. 49).

11) Improve forecast documentation. (p. 50).

VI. SUPPLY PLAN REVIEW

A. Introduction

The Council's review of the Northeast Utilities Companies' supply plan focuses on two documents: the Long Range Forecast of Electrical Loads and Power Facilities Requirements in Massachusetts 1981 Through 1990, Volume 2, "Power Facilities Forecast", filed April 1, 1981 ("Forecast, Vol. 2"), and Northeast Utilities Conservation Program for the 1980's and 1990's ("Program" or "Conservation Program"). The latter document, dated January 1981, was originally prepared in response to a directive by the Connecticut Department of Public Utility Control.[31] The Conservation Program has two major objectives which are designed to reduce the NU service area's dependence on imported oil. Appropriately, they include both demand and supply-side initiatives: First, the Companies' "demand-side" objective is to expand "activities which will assist customers in using electricity and all forms of energy more efficiently and in reducing their direct use of oil."[32] The second, "supply-side" objective is to accelerate "the reduction in the use of oil for generating electricity."[33]

The program's demand-side efforts consist of a veritable cornucopia of customer conservation activities. Elements of the Program attempt to increase customer awareness of the potential for end-use conservation, to provide information about preferred technical and cost-effective

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31 The Council has previously cited this program as a positive example of innovative supply planning. See in Re Cambridge Electric Light et al, 6 DOMSC at 26, (1981).

32 Program, p. 12.

33 Program, p. 12.

means to put conservation measures into effect, and finally, to provide services and incentives to accomplish the specific conservation measures. The Companies hope that the successful implementation of these conservation measures will constrain growth in electricity demand to no more than 1.5% per year over the long-term.[34]

The Conservation Program's supply-side efforts attempt to reduce the Companies' use of oil for power generation from 47.2% in 1980 to only 10% by 1993 (See Table 8). This is to be achieved by completing the construction of the Millstone 3 nuclear unit, by converting 8 oil fired units to coal-fired, and by increments of domestic and imported hydroelectric power, refuse derived energy, fuel cells, wind power, and purchases from cogenerators and small power producers. Table 8 illustrates the Companies' projected changes in its resource mix by 1993. It is noteworthy both for the extent of its diversification away from oil-fired generation and for planned utilization of indigenous energy resources. Table 9 details the estimated annual oil savings projected to be achievable from specific technologies in the resource mix by 1987. Order-of-magnitude investment costs, per technology, are also given. Table 10 illustrates the cumulative oil savings ("reduction") in barrels and in dollars, and the cumulative net savings to NU's customers over the first 12 years of the Program. Over 90% of the projected savings are due solely to completion of Millstone 3 and successful conversion of the 8 oil-fired units.

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34 The 2nd. Forecast projected a peak load growth rate of 1.9%. The recently filed Supplement to the 2nd Forecast projects 1.6% through the forecast period.

The Council's Supply Plan Review will focus first, in Section B, on the customer assistance conservation measures in the Companies' Conservation Program. In Section C, we will look at the Companies' efforts to convert the West Springfield and other units to coal. Section D will briefly address potential reliability problems at the Millstone 2 unit and Section E will discuss Millstone 3 and an economic analysis that compares the cost-effectiveness of completing Millstone 3 vis-a-vis certain conservation investments.

Table 8

Northeast Utilities Companies

Comparison of Energy Resource Mix in 1980, 1987, and 1993

Resource	1980 MW	1980 GWh	1980 %	1987 MW	1987 GWh	1987 %	1993 MW	1993 GWh	1993 %
Nuclear[1]	2009	10780	48.1	2757	16460	66.2	2575	16950	62.3
Coal Conversion[2]	0	0	0.0	850	4460	17.9	850	4830	17.7
Hydro[3]	242	640	2.9	271	930	3.8	271	930	3.4
Cogeneration[3]	0	0	0.0	100	610	2.5	100	610	2.3
Refuse-Derived Energy[3]	0	0	0.0	80	560	2.2	80	560	2.1
Wind[3,4]	0	0	0.0	4	8	0.0	4	8	0.0
Non-Oil Technologies[5]	-	410	1.8	-	-	-	-	600	2.2
Oil	2720	10580	47.2	1980	1850	7.4	1650	2720	10.0
Total		22410	100.0		24878	100.0		27208	100.0

1. Assumes retention by NU of 65 percent ownership of Millstone Unit 3.
2. Assumes no flue-gas desulfurization.
3. Any increased contribution from these resources after 1987 is included in the estimated total for the Non-Oil Technologies.
4. Provided large windmill demonstration goes forward.
5. MW capacity depends on mix of alternatives selected.

Source: p. 81-90, Program.

Table 9

Northeast Utilities Companies

Summary of Supply Conservation Program by 1987

Technology	Elements of Program MW	Net Increases in System Capacity MW	Estimated Oil Savings Achievable in 1987 (millions of barrels)	Total Investment Required (Millions of dollars)
Millstone Unit 3[1,5]	750	750	7.5	$1,700
Coal Conversion	850	-	7.5	289
Refuse[2]	80	80	1.0	24
Small Hydro	35	35	0.2	55
Cogeneration[3]	100	100	1.0	-
Wind[4]	4	4	0.014	10
Efficiency Improvements	0	0	0.3	4
TOTAL	1819	969	17.5	at least $2 billion

1. Reflects NU's present 65 percent ownership in Millstone Unit 3. Each 100 MW sold increases oil dependence by 1 million barrels.
2. Assumes supplemental coal-firing.
3. Ownership and cost cannot be determined at this time.
4. Provided large windmill demonstration goes forward.
5. It is assumes that NU's remaining share of Seabrook ownership will have been disposed of by 1987.

Source: p. 83, Program

Table 10

Northeast Utilities Companies

Summary of Cumulative Energy Savings, Cost of Oil Saved and Cumulative net Savings to Customers, 1981-1993

	Oil Reduction (Millions of barrels)	Oil Reduction Share %	Cost of Oil Saved (Billions of $)	Cumulative Net Savings (Billions of $)	Cumulative Net Savings Share %
Millstone Unit 3[1]	57	33.5	5.8	2.1	33.8
Coal Conversion	69	40.5	6.5	3.7	59.7
Generation from Refuse Derived Energy[2]	8	4.7	0.8	-	-
Hydro Additions	2	1.2	0.2	0.1	2.0
Cogeneration[3]	10	0.6	0.9	0	-
System Efficiency Improvements	3	1.8	0.3	0.3	5.0
Customer Assistance Conservation Program (NU System)[4]	21	12.4	1.9	-	-
	170(5)	100.0	16.9	6.2	100.0

1. Assumes 65 percent ownership.
2. Cumulative net savings to customer cannot be specified because technology and contractural arrangements with Conn. Resources Recovery Authority not yet determined.
3. Cogeneration oil savings reflect estimated oil reduction by NU only. There are no cost savings to customers becau purchase rates will be based on the avoided cost of oil.
4. Customers are assumed to avoid $1.6 billion in energy costs through their own efforts in response to the customer assistance program. A detailed cost benefit study of customer conservation measures, which would include the calculation of financing costs and Maintenance expenses, would be needed to develop a cumulative net savings calculation comparable to that developed for the supply technologies.
5. Total oil reduction of 170 million barrels is in addition to the oil savings from reducing the projected growth rate in electricity requirements from 2.6 percent to 1.5 percent. This lower growth rate means that an additional over 50 million barrels of oil worth $5 billion would not have to be used.

Source: p. 109, Program.

B. Customer Conservation Activities

The Council has been actively encouraging the development of so-called "demand management" supply options since 1980.[35] These options include a variety of measures that promote beneficial modifications to a system's load characteristics and/or reduce oil utilization. Besides reducing oil dependency and hopefully, ratepayer bills, these efforts can also help defer expensive capacity additions or provide some degree of insurance against uncertain demand forecasts and the commercial operation dates of major new facilities.[36] The Council has been careful to avoid prescribing specific program measures or technologies for want of an appropriate methodological basis for doing so and because system service territories wary so widely in terms of their respective needs and resources. These circumstances have not changed with the present filing from NU.

The Council applauds the breadth and depth of the customer conservation activities which are being promoted in the Companies' Conservation Program for the 1980's and 1990's. Table 11 lists each measure by customer class and by program category. <u>The immediate benefit of this comprehensive package of measures is the acquisition of territory specific experience and data which will facilitate the determination of each measures' relative cost-effectiveness within the context of the Companies' overall long-range planning.</u> Recognizing NU's limited access to capital funds[37], it is imperative that the Companies

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35 See: In Re Eastern Utilities Associates, 5 DOMSC 10, 38 (Nov. 24, 1980).

36 <u>Supra</u> at 33, also see: In Re Massachusetts Municipal Wholesale Electric Company, 5 DOMSC 53 at 89, 89 - 96 (Jan. 13, 1981).

37 And, perhaps, the equally difficult task of obtaining full cost recovery because customer rates are already burdensome.

Table 11

Northeast Utilities Companies

Northeast Utilities Conservation programs for the 1980s and 1990s
Programs to Assist Customers Conserve Energy

PROGRAM CATEGORY	ALL CUSTOMERS	RESIDENTIAL CUSTOMERS	COMMERCIAL/INDUSTRIAL (C/I) CUSTOMERS	MUNICIPALITIES
AWARENESS PROGRAMS	Operation WARM: Aerial Thermography Overflight	Energy Efficient Home Award (National Energy Watch - N.E.W.)	C/I National Energy Watch Award	C/I National Energy Wat Award
INFORMATION PROGRAMS	Encouragement of Customer-Owned Cogeneration and Small Power Production	Residential Conservation Service Program - CONN SAVE, Mass SAVE - Home Energy Audits	Energy Audits for Small Commercial/Industrial Customers	Building Energy Audits
		Efficient Appliance Information (including the heat pump)	Energy Audits for Medium-Sized Commercial/Industrial Customers	
		Builders, Developers, Lenders: Information Sessions, Newsletter	Energy Management Emphasis Periods for Large Commercial/Industrial Customers	
		Energy Conservation Information on Utility Bill		
			Technical Courses	Coordination of Energy Conservation Assistance
				Streetlighting Efficiency Improvement
SERVICE AND INCENTIVE PROGRAMS	Solar Program: Technical Assistance, Design Award	Operation Wrap-Up and Turn-Down (insulating water heaters, turning down aquastats and and installing shower-heads)		
		Solar/Electric Controlled Water Heating Incentive and Evaluation		
		Maximum Ceiling Insulation Incentive		
		Introduction of Radio Control for Electric Water Heaters	Radio-controlled Water Heating Rate	Radio-controlled Water Heating Rate
		Residential Demand Limiting Rate	Demand Limiting Rate	
		Residential Time-of-Day Rate	Interruptible Rate for Loads Subject to Radio Control	
		Conservation Rate		
		Urban Winterization		

Source: Program, p. 19.

prioritize these efforts by their respective cost-effectiveness, vis-a-vis competing investment needs for Millstone 3 and coal conversions. Having launched this ambitious program, the next important step is detailed analysis of each measure's life cycle costs and benefits. In this regard, the Council's determination parallels and supports the position of the Executive Office of Energy Resources ("ECER") in the recent WMECo rate case at the DPU (DPU 957). In that case, EOER asked the DPU to order WMECo:

(i) to evaluate the cost-effectiveness of each part of the program for each of the following: the utility system (including non-participating ratepayers), participating ratepayers, and society as a whole;

(ii) to collect data on customer participation, saturation of program measures, demographics of program participants, program goals attained, measures implemented, and energy savings achieved; and

(iii) to maintain accounting records on receipts and expenditures, relating to the program."[38]

The DPU subsequently ordered "a comprehensive analysis of the costs and benefits of the Program" but did not specify a particular methodology or approach, nor detail what issues needed to be addressed in such an analysis.[39] The Council believes that the need for this analysis is overdue, both for NU and other Massachusetts electric companies, given the current proliferation of utility-sponsored conservation initiatives. Recognizing this urgent need, the Council here directs the Companies, as a <u>CONDITION</u> to this <u>Decision and Order</u>, to develop a specific, long-range, cost-benefit analysis of each of the conservation and alternative

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38 <u>Reply Brief of the Commonwealth of Massachusetts Executive Office of Energy Resources</u>, DPU 957, April 22, 1982, p. 5.

39 Western Massachusetts Electric Company, DPU 957, p. 65 (1982)).

energy sources outlined in the NU Program for the 80's and 90's, to be included in the next filing with the Energy Facilities Siting Council. The Companies' long-range forecasting methodology is an appropriate vehicle for this analysis. At the heart of the matter (i.e., the cost-effectiveness of customer assistance conservation programs, load management, and renewable energy options) is the adequate estimation and treatment of long-run costs and benefits. These costs and benefits are inherently sensitive to future fuel prices, real escalation rates, the rate of inflation, and a discount rate, which are also important parameters in the Companies' Long-Range Forecast to the Council. Both the EOER and the DPU recognize the importance of these parameters and the assumptions that underlie their utilization within an internally consistent methodological framework.[40]

The Council also believes that the Companies' forecasting methodology, particularly its peak load forecast model, is now sufficiently sophisticated and detailed to reliably estimate long-run incremental capacity requirements, which is necessary if long-run incremental costs are to be addressed adequately. A certain level of detail, e.g. projected hourly demand, is important to correctly capture the impacts on system load characteristics of specific demand management technologies. The work of the Companies in comparing Millstone 3 costs with conservation scenarios also puts them in a good position to address these issues.[41]

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40 See supra, p. 64; also, Reply Brief of the Commonwealth of Massachusetts Executive Office of Energy Resources, DPU 957, April 22, 1982, pp. 3 and 6.

41 See discussion infra., part VI (E).

Finally, any appropriate methodology for estimating the cost-effectiveness of conservation or demand management measures must also account for other exogenous parameters such as energy prices and income. Future demand for electricity (both kW and kWh) will be sensitive to rates, rate structures, the prices of oil and gas, customer incomes, and other factors. The Companies' long-range forecast considers elasticities and further development and enhancements to this capability have already been suggested and encouraged by the Council, as discussed <u>supra</u>.

In fulfilling the above stated CONDITION, the Companies should explicitly address the following issues, as enumerated in the EOER Reply Brief:[42]

"(i) How much conservation or demand reduction is attributable to the utility program versus other exogenous vatiables, e.g., energy prices, weather, general economic conditions, or governmental programs?

(ii) Will conservation/load management programs produce short-run operating cost savings for the utility system other than lowering average fuel prices?

(iii) How do you evaluate the benefits to utility ratepayers of programs that defer future capacity additions with increasing marginal costs?

(iv) Can diversification of the utility supply mix reduce financial risks to stockholders and ultimately lead to lower rates for customers?

(v) Will lost electricity sales due to conservation result in higher rates to consumers or will consumers be held harmless by offsetting increases in load growth?

(vi) What is the nature and amount of the social spill-over benefits and costs from conservation/load management programs?"

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42 See: <u>Reply Brief</u>, supra, at 6.

The Companies should also evaluate the tradeoffs between cost, methodological detail, and analytical accuracy. Obviously, for example, the expenditure of $20,000 to perform a detailed cost/benefit analysis on a $50,000 program would not be a prudent use of the Companies' funds, when a more simplified (and cheaper) approach may be sufficiently accurate for efficient decision-making.

Finally, the Companies should evaluate the extent to which diversification of the system's supply mix, with both demand and supply-side initiatives, impacts system reliability.

The Council requires that this CONDITION be completed by the May 28, 1983. The Companies may choose to accelerate this schedule to comply with or to supplement appropriate filings at the MDPU or the CDPUC. By the May 28, 1983 filing date, two full calendar years of experience will have been achieved which should provide sufficient data for long-term appraisal and planning of the Companies' important initiatives.

C. Coal Conversion

As discussed supra, Northeast Utilities seeks to reduce its reliance on imported oil. Specifically, it is the Companies' stated objective to reduce its overall oil dependence from approximately 47 percent to 10 percent or less by 1987[43]. The 10 percent target is deemed achievable through certain scheduled capacity additions[44], planned coal conversions, alternative energy resources, and controlled growth in electricity sales. (See Table 9).

Of particular interest to the Council is the timely conversion to coal of the West Springfield units 1, 2, and 3, which have winter capacity ratings of 51.5 MW, 51.5 MW and 108.3 MW, respectively. The units presently burn 2.2% sulfur No. 6 residual oil and are wholly owned by Western Massachusetts Electric Company.[45]

The Companies have testified that conversion of the West Springfield units cannot be accomplished as expeditiously as that which is taking place at the Mt. Tom unit.[46] Specifically, extensive air quality monitoring must be done before detailed engineering is possible and additionally, a "full-blown" MEPA process will be required by the

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43 Program, pp. 15-17.

44 Mostly Millstone 3. See: Table 9, "Summary of Supply Conservation Program by 1987".

45 Under the terms of the Northeast Utilities Generation and Transmission Agreement("G & T"), which defines how adjustments for shared costs are made among the NU subsidiaries, approximately 75% of the power from the West Springfield units is sold to customers in Connecticut. Savings occuring from conversion to coal will be allocated in the same percentage to Connecticut & Massachusetts ratepayers.(pp. 26-27, Transcript, Vol. 2.)

46 The Companies entered into a memorandum of Understanding ("MOU") with the Governor of Massachusetts and Commissioner of the Department of Environmental Quality Engineering on the matter of the Mt. Tom Conversion. (See Final Environmental Impact Report on the Mt. Tom Coal Conversion Project ("FEIR") App. 1.) The MOU set forth the Commonwealth's commitment to the project under stated (footnote continued on following page)

...mental Quality Engin
...ty modeling protocol for West Springfi
submitted to the U.S. Environmental Protection Agency in
and was approved by the EPA in April, 1982. A final repor
modeling is due sixteen months after commencement of the pr
Once air quality modeling is complete, detailed engineering
of the conversion can begin. The Companies believe that engi
begin no earlier than mid-1983, resulting in the first coal bu
station's unit 3 by January, 1985. (See Table 12, "Proposed Sc
for Conversion of NU Oil-Burning Generating Units to Coal, 1981-
Units 1 and 2 would begin burning coal one year later.

The conversion process at each unit takes place in two steps
First, during a 6-week maintenance outage, the unit's coal-firing
ability is restored. However, it would not be in compliance with
national secondary air quality standards.[49] The Companies would nee
delayed compliance order (DCO) from the U.S. Environmental Protection

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(continued from preceeding page) environmental impacts or limits and cost recovery guidelines and, thus eliminated the need to consider alternatives" to the project within the MEPA process. (FEIR, Part V.) Since that time, the General Court has institutionalized the cost recovery mechanism for such projects and vested authority in the DPU. MGL Ch 164 Sec. 94G1/2. Thus, it is likely that any similar project carried out at the West Springfield units would follow this regulatory process.

In addition, the US DOE's Order prohibiting the use of oil as a fuel at Mt Tom was issued pursuant to the Energy Supply and Environmental Coordination Act of 1974 ("ESECA") 15 USC Secs. 791 et seq, in 1977. Any such order for the W. Springfield Unit would have to be issued pursuant to the Industrial Fuel Use Act of 1978.

47 42 USC Secs. 8301 et seq.

48 pp. 24-25, Transcript; Vol. II, p. 173, Cross Examination of W.F. Fee, DPU 957; Exh. COAL-22, DPU 957.

49 p. C-35, Exh. COAL-1, DPU 957, "Air Quality Modeling Protocol for West Springfield Station Coal Conversion" The City of Springfield is a designated non-attainment area for secondary TSP standards.

Table 12

Northeast Utilities Companies

Proposed Schedule for Conversion of NU Oil-Burning Generating Units to Coal, 1981-1986 (1)

	Capacity on Oil (MW)	Capacity on Coal(MW)	In-service On Coal DCO(3)	Total NU Cost (Millions of $)(2)	Conversion Cost Per MW Capacity ($000)
Units in Massachusetts:					
Mt. Tom (NU 62% portion)	92.0	90.2	12/81	$ 22m	$244
W. Springfield 1	51.5	51.0	1/86	24m	471
W. Springfield 2	51.5	51.0	1/86	24m	471
W. Springfield 3	108.3	107.0	1/85	45m	420
Mass. Sub-Total	303.3	299.2		$115m	$384
Units in Connecticut:					
Norwalk Harbor 1	164.0	159.8	1/85	$ 36m	$225
Norwalk Harbor 2	174.0	171.5	7/85	40m	233
Devon 7	109.0	107.0	1/86	49m	458
Devon 8	109.0	107.0	1/86	49m	458
Conn. Sub-Total	556.0	545.3		$174m	$319
TOTAL	859.3	844.5		$289m	$342

NOTES:

1. Capacity of units when converted to coal, capital cost estimates, and the schedule shown here assume conversion without flue-gas desulfurization.

2. Capital Cost estimates as of 10/81.

3. DCO (Delayed Compliance Order) process to be used, in accordance with U.S. EPA and DOE regulations.

Source: DPU 957, Exh. WFF-4

Agency to actually begin burning coal.[50] With the DCO, the Companies hope to use the Oil Conservation Adjustment (OCA) mechanism to finance the remainder (and bulk) of the conversion costs necessary to achieve air quality compliance. This second step in the conversion process would begin from 18 to 24 months after the DCO were issued. A 12-week maintenance outage would be scheduled for the unit for construction and installation of pollution control equipment.[51]

The proposed two-step conversion process highlights a critical issue for the Companies - namely, the financing of the conversion costs. The Companies' financial health is not sufficiently strong so as to easily accommodate the cost of financing the proposed conversions which must compete for capital with the Companies' on-going investment in Millstone 3. This fact has been underscored by the recent WMECo rate case at the Massachusetts Department of Public Utilities ("DPU"). In that case, the DPU raised NU's Massachusetts subsidiary's allowed rate of return on equity from 16 to 17% because "... the [Company's] actual return on equity is still significantly below the 16 percent last allowed, and the market-to-book ratio is substantially below 1.0. AFUDC as a percentage of income remains high, interest coverage is minimal, and bond ratings are still very low."[52] To further shore up its financial strength, WMECo is attempting to reduce its ownership in the Millstone 3 nuclear project from 12.35% (142 MW) to 8.46% (97.3 MW).

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50 The DCO allows the temporary violation of <u>secondary</u> standards but not the threshold <u>primary</u> standards.

51 pp. 54-55, Transcript; Vol II, p. 179, Cross-examination of W.F. Fee, DPU 957.

52 Western Massachusetts Electric Company, DPU 957, p. 32

From Table 12, it is clear that the Companies are attempting to minimize the short-term financial burden of coal conversion by converting first the units which are relatively cheaper, on the basis of conversion costs per MW capacity.

Thus, the Council would anticipate the two Norwalk Harbor units ($225-233 per MW) in Connecticut to have a higher priority than the West Springfield units ($420-471 per MW), ceteris paribus. Massachusetts ratepayers are expected to benefit from the conversion of the units in Connecticut, to the extent allowed by the "G & T" Agreement. The financial hurdles necessary at each unit to be converted are: first, the front end costs associated with restoring the unit's ability to burn coal; and second, getting a DCO from the EPA and OCA approval from both the Massachusetts DPU and the Connecticut DPUC.

The Companies are urged to expeditiously seek the requisite permits and financial support with the Council's wholehearted support.

D. Millstone Unit 2 Reliability

During the proceedings of this case, the EFSC Staff expressed concern with potential steam generator tube degradation problems at the Companies' Millstone 2 Nuclear unit, located near Waterford, Connecticut. The pressurized water reactor (PWR) has a rated capacity of 868.5 MW, of which 19% (165 MW) is owned by the Western Massachusetts Electric Company.[53]

In PWR's, water in the primary coolant system is kept under pressure to prevent it from boiling. This high-pressure water passes through tubes around which water circulates in a secondary system where steam is produced to drive the turbine generators. The assembly in which the heat transfer takes place is the steam generator. The tubes within it are an integral part of the primary coolant system, keeping the highly radioactive primary coolant in a closed system, isolated from the environment. These tubes form a principal part of the reactor coolant pressure system and constitute its largest surface area. PWR steam generators have experienced a variety of tube degradation problems for a number of years and are caused by a combination of corrosion and/or mechanical conditions.[54] In January, 1982, Rochester Gas and Electric Company's 470-MW Ginna PWR nuclear unit was forced into a cold shutdown after the rupture of a steam generator tube, resulting in the release of radioactive gas to the atmosphere.[55] Of concern to the Council, which does not have jurisdiction over the operational safety of generating

53 Forecast, Volume 2, p. III-16
54 EFSC Exh. 1, p. 1
55 Electrical World, Feb. 1982, p. 11

units[56], is the nature of the steam generator tube problem at the Companies' Millstone 2 unit and its potential impact on future availability of that unit. Chronic outages of nuclear units can have devastating impacts on ratepayer bills because replacement power during outages is from typically expensive and relatively inefficient oil-fired generation.

The EFSC Staff's review of this issue was assisted by the timely release of an NRC staff report, Steam Generator Tube Experience[57], in February, 1982. This report, which was allowed into evidence at the April 20th Hearing, adequately discussed the history of the Millstone 2 tube problem and its current status. According to the NRC report, the unit had experienced a "moderate" amount of denting in the past.[58] Denting is the deformation of the tubes due to a buildup of corrosion products. Corrective actions were taken by the Companies in 1977. This included the retubing of the condensors with 90-10 cupro-nickel, the installation of a full flow condensate polishing system, the elimination of hardspot areas in the support plates, and improved water chemistry control (so as to minimize the causes of corrosion). Tube inspections performed during an August 1980 outage indicated that the denting had been stabilized.[59] The report later states that "... the NRC staff has been evaluating adverse [steam generator tube] experience on a case by case basis and has concluded that continued operation and licensing do

56 42 USC Secs 2011 et seq. Northern States Power Co. v. Minnesota 447 F. 2d. 1143 (8th Cir., 1971), affirmed per curiam 405 U.S. 1035 (1971)

57 (NUREG-0886, Division of Licensing, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission*

58 EFSC Exh. 1, p. 28.

59 EFSC Exh. 1, pp. 28-29

not constitute an undue risk to the health and safety of the public."[60] The Council is favorably reassured by the NRC report and requests that the Companies keep the Council informed of any significant changes in the reliability of the Millstone 2 unit due to the denting potential.

60 EFSC Exh. 1, p. 54

E. Comparative Economic Analysis of Conservation and Millstone 3 Investments

Northeast Utilities is presently building the 1150 MW Millstone 3 nuclear unit at Waterford, Connecticut. NU subsidiaries currently own 65% of the unit, or 747.5 MW of the unit's ultimate winter rated capacity. WMECO currently owns 12.35% (142 MW). Since January 1981, the Companies have attempted to sell an additional 100 MW of its total share because of difficulty in financing such an effort. Having secured firm commitments for only approximately 60 MW, the Companies still expect to pay $2261 per kW capacity for Millstone 3[61], compared to $163, $154, and $488 per kW for their existing nuclear units, Connecticut Yankee (580 MW), Millstone 1 (660 MW), and Millstone 2 (870 MW), respectively.[62] The completed sale of the additional 60 MW Millstone 3 capacity would reduce WMECO's ownership from 12.35% (142 MW) to 8.46% (97.3 MW).

The fact that electric utilities throughout the country are having extreme difficulties financing the construction of major generating units (typically nuclear) and in many cases are cancelling or delaying these units, is well publicized and controversial. Within the past year, the Pilgrim 2 unit was cancelled by the Boston Edison Company, and the Public Utilities Commission of New Hampshire has recently opened hearings with respect to the potential delay of Seabrook unit 2.

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61 See Table 13

62 Data request CLF-1, Conn. Docket Nos. 810602/810604; p. iii, First Supplement, 2nd. Forecast, Vol. II

Table 13

Northeast Utilities Companies

Capital Costs per Unit Capacity of NU's Nuclear Power Plant

Existing Units	Site	In Service Date	Winter Rated Capacity (MW)	Current NU Subsidiaries Entitlement (%)	Capital Cost per kW (Nominal $)
Connecticut Yankee	Haddam Neck, CT	1968	580.0	44	$163
Millstone 1	Waterford, CT	1970	660.0	100	$154
Millstone 2	Waterford, CT	1975	868.5	100	$488
Unit Under Construction					
Millstone 3	Waterford, CT	1986	1150.0	60	$2261

Sources: 2nd. Forecast, Vol. II; Data Request CLF-1, Conn. Docket Nos. 810602/810604

These circumstances are of concern to the Council because these units offered the promise of substantially reduced oil usage by the region's power companies and also because their cancellation or delay adds considerable uncertainty and expense to projected capacity needs, thus stifling the Council's mandate to minimize uncertainties and costs. It is also of concern that utilities may not be fully developing conservation scenarios as part of their supply plans.

Since the Millstone 3 project is technically grandfathered from the Council's review, and is located in another state,[63] the Council cannot and would not attempt to judge the merits of the facility. However, the record in this proceeding contains an interesting economic analysis which compares the long-run cost-effectiveness of the Millstone 3 investment with the alternative strategy to cancel the unit and invest the remaining construction costs (estimated to be approximately $1 billion) in various conservation efforts. The Council notes that this analysis was not formally sponsored by a party in this case nor was it extensively reviewed with respect to alternative assumptions.[64] The Council draws attention to the Companies' analysis for the sole purpose of nurturing public inquiry and debate on this critical issue, and therefore, no conclusions or findings of fact will be drawn from this analysis. Perhaps excepting further oil price increases, nothing may impact future power costs to Massachusetts ratepayers more than the

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63 See: Appendix "C" Memorandum and Order, pp. 8-11.

64 Such a review was the focus of the Conservation Law Foundation's brief intervention, and subsequent withdrawal, from the proceedings. Rather than sponsor an alternative analysis themselves, CLF attempted to pursue these issues through discovery. (See <u>supra</u>, part II.)

ultimate disposition of the region's investments in Millstone 3, and Seabrook 1 and 2.

The Companies' analysis, entitled "Conservation and Millstone 3 Alternatives Economic Analysis", was performed under order from the Connecticut Department of Public Utility Control.[65] The analysis compared the projected present worth costs and benefits of conservation investments with continuing the current construction schedule for Millstone 3. The conservation measures included major investments in heat pump water heaters, energy efficient appliances, window shades and glazing, commercial and industrial audits, and six other initiatives.[66] Additionally, 400 MW of cogeneration and small power producers are assumed installed by 1994 for capacity deficiency reasons. The analysis first assumed that the $1 billion conservation investment would be rate based. It was performed a second time with the hypothetical assumption that the same conservation investments would have a zero cost to remove the argument that the Companies' estimates for the conservation investments were inaccurate. In both cases, continuing the present Millstone 3 construction schedule was the more economic choice for the Companies' customers. It must be noted, however, that the conservation case included the full recovery of Millstone 3 sunk costs and cancellation charges with unrecovered balances included in the rate base.

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65 Late filed Exh. 19, Conn. Docket Nos. 810602/810604, August, 1981.

66 The CONDITION to this Decision and Order, discussed supra, in Section VI (B), relates, in part, to a more accurate determination of the most economically efficient conservation measures.

F. Conclusion: Supply Plan Review

The Northeast Utilities Companies' Supply Plan is hereby APPROVED subject to the CONDITION stated *supra*, in Section VI (B).

The Council endorses the overall thrust of the Companies' supply planning strategies, as developed in the NU 80's and 90's Program, but additional effort is necessary to rank the relative cost-effectiveness of each component in the program. The Condition to this *Decision and Order* is directed to this end. The successful implementation of the Companies' ambitious 80's and 90's Program is contingent on more accurate estimates of each measure's long-run costs and benefits in the context of the Companies' long-range forecast of electric power needs and requirements. This effort can thus ensure the Council's mandate to provide a reliable, safe supply of electricity to the Commonwealth at the least possible cost.

The Companies are required to consider the suggestions outlined in the preceding pages, as follows:

1) Expeditiously seek the required permits and financing for its coal conversion program. (p. 68) *infra.*
2) Keep the Council informed as to an significant changes in reliability due to denting problems at Millstone 2. (p. 71) *infra*.

VII. DECISION AND ORDER

The Council hereby APPROVES the Second Long-Range Forecast of Electric Needs and Requirements of the Northeast Utilities Companies subject to the following.

The Companies are hereby ORDERED:

1. To submit to the Council no later than its next scheduled filing a specific, long range, cost benefit analysis of each of the conservation and alternte energy sources outlined in the NU Program for the 80's and 90's which will comply with the discussion of this analysis in part VI (B) supra, and compare the benefits of those investments to the benefits of the Companies' present oil displacement investments.
2. To meet with the Council staff within ninety (90) days of this ORDER and present an outline of the cost benefit analysis which the Companies propose to utilize and revise the content of the submittal ordered in condition number one if appropriate.

Energy Facilities Siting Council

Paul T. Gilrain, Esq.

Hearings Officer

On the Decision:

John Hughes
Margaret Keane
JoAnne Bos

This decision was unanimously approved by the Energy Facilities Siting Council at its meeting on June 28th, 1982 by those members present and voting.

Voting in favor: Margaret N. St. Clair, Esq., Secretary of Energy Resources; Bernice McIntyre, Esq., for the Secretary of Environmental Affairs; Noel Simpson, for the Secretary of Economic Affairs; Richard Pierce, for the Secretary of Consumer Affairs; Harit Majmudar, Public Member, Electrical; Thomas Crowley, Public Member, Engineering.

Ineligible to Vote: Dennis Brennan, Public Member, Gas; Charles Corkin II, Esq., Public Member, Oil.

Date

Margaret N. St. Clair
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Taunton Municipal Lighting Plant's Petition for Approval of Its 1979 Occasional Supplement to Its Long-Range Forecast of Electric Power Needs and Requirements (August 1982)	EFSC 79-51A

FINAL DECISION

Robert T. Smart Jr., Esq.
Hearing Officer

On the decision:

George Aronson, Staff Analyst

The Massachusetts Energy Facilities Siting Council (hereafter "Council") hereby ALLOWS the Taunton Municipal Lighting Plant (hereafter "TMLP" or the "Plant") to begin design specification work on, and to commence local licensing of, its proposed new 115 kV transmission line and substation in the City of Taunton. The Plant may commence construction as soon as it submits its next filing, the combined Second Long-Range Forecast and First Supplement thereto.

I. HISTORY OF THE PROCEEDINGS

The TMLP filed an Occasional Supplement with the Energy Facilities Siting Council on April 17, 1979, under Council Rule 65.3. In the Occasional Supplement, the Plant described its construction proposal, and asked for Council approval. The Hearing Officer, after requiring notification by publication, posting, and direct mailing to abutters, held a local informational hearing at the TMLP Auditorium on June 5, 1980. Members of the public voiced concerns about interference with radio and television reception, and there was some discussion of alternative routes and sites. The Hearing Officer and the Council Staff viewed three alternative transmission line routes and the several substation sites on the day of the local hearing.

Twenty-nine persons, all abutters or within view of the proposed transmission line route, petitioned to intervene on June 20, 1980. The intervenors' petition claimed the line would cause unreasonable visual impact, that two alternative routes ("West" and "Central" in the Occasional Supplement) would present less "personal and environmental impact", that expansion of the facilities was not needed, and that additional transmission facility siting did "not represent a cost effective means of providing power to the residents of the City of

Taunton". The intervenors, by their attorney, Clyde Hanyen, participated in discovery, but withdrew from the proceedings before the hearings were held. Attorney Hanyen informed the Hearing officer by telephone on April 29, 1981 of the withdrawal, and stated that negotiations with TMLP regarding indemnification for interference with television reception were proceeding in a manner satisfactory to himself and his clients.

The first hearing was held at the EFSC offices on April 30, 1981. Michael Horrigan, Electrical Engineer for TMLP, and William McAloon, Executive Director of the Taunton Development Corporation, testified for the Plant. The Council Staff cross-examined these witnesses extensively. Fifteen exhibits were introduced by the Plant.

On July 13, 1981, a Tentative Decision was mailed to the TMLP, to be voted upon at the July Council meeting. That Decision would have prohibited construction until the TMLP produced additional evidence of load growth at the Myles Standish Industrial Park, and filed and obtained Council approval of its Fourth Annual Supplement. The Staff was very concerned about TMLP's failure to file, in timely fashion under G.L.c. 164 sec. 69I, a Fourth Supplement after the Council decision on the Third Supplement, which was issued in February of 1980. That Third Supplement had been found by the Council to be deficient in several respects. The TMLP, by its local Attorney, Edward A. Roster, asked that the matter be taken off the July Council meeting agenda. This was done. On July 31, 1981, TMLP filed a Motion asking that the proceeding be re-opened so that "extremely important new evidence" could be taken. It also expresses willingness to discuss with the Staff the filing of a new annual forecast. On August 17, 1981, the Council directed the Staff to withdraw the Tentative Decision, take additional evidence, and to work out an appropriate agreement regarding the next filing.

Two productive "technical sessions" on the content of TMLP's next filing were held in September, 1981 between the staffs of the Plant and the EFSC. Over the next seven months the TMLP requested and received several extensions on the filing of a "Compliance Plan" describing its forecasting efforts. On May 14, 1982, it filed its Plan, with which the Staff is quite pleased.

On July 2, 1982 the TMLP submitted the written testimony of Peter J. Thalmann, and the supplemental testimony of Michael J. Horrigan and William A. McAloon. On July 27th, the Plant filed responses to a second round of Staff information requests. At the second hearing, held on July 28, 1982, Mr. Thalmann and Mr. Horrigar were cross-examined.

II. ANALYSIS

A. Description of the Proposed Line

1. Existing Facilities

TMLP presently serves the Whittenton area of Taunton by the Whittenton (No. 5) and Fremont Street (No. 9) 13.8/4.16 kV distribution substations located north of the population center of Taunton. These two substations are served by three 13.8 kV distribution circuits. Two circuits (2 G14.51 and 2 G14.52) serve the Fremont Street substation from the Cleary Flood Generating Station. One circuit (G14.51) serves the Whittenton substation from the West Water Street 115/13.8 kV substation, which is served in turn by a 115 kV line from Cleary. Two 13.8 kV distribution lines (314.51 and 314.52) run between the Whittenton and Fremont Street substations to complete a transmission loop. These two lines also serve the Myles Standish Industrial Park area (see system map, Ex. 4, and corresponding system schematic, Ex. 3).

2. Proposed Line and Substation

TMLP has proposed to effectively replace the three 13.8 kV distribution circuits to the Whittenton Area (2 G14.51, 2 G14.52 and G14.51) with a double 115 kV distribution circuit. The proposed line would provide firm power supply with a single contingency to the existing load in the Whittenton area and to developing loads in the Myles Standish Industrial Park.

The 115 kV line would start at the existing 115 kV line from Cleary to West Water Street, and would substantially follow an existing railroad right-of-way to the proposed new substation site (Whittenton Junction) just north of West Brittania Road. It is designed to be 3.7 miles long and be supported by steel poles. The proposed substation is rated 115/13.8 kV, and measures approximately 200' by 220' of low profile design on a site of 2.92 acres. The substation would tie into two 13.8 kV lines (314.51 and 314.52, in the existing distribution system.

The proposed line and substation together would take approximately two years to complete, given 1 year of lead time for design, local licensing and ordering of equipment, and at least 1 year for construction.

3. Costs and Financing

TMLP estimates that the transmission line will cost $985,000 and that the substation will cost $1,010,000 (Ex. 16, Ex. PT7). These cost estimates are based on TMLP historical costs for similar projects, updated as necessary with escalators from the Handy-Whitman Guide to Cost Trends of Electricity Utility Construction for the North Atlantic Region.

TMLP plans to use its Depreciation Fund to pay for the project. By law (M.G.L. C. 164 sec. 57), TMLP takes from its annual revenues an amount equal to 3% of the cost of its plant for deposit in the Depreciation Fund. Municipal utilities may use their Depreciation Funds to pay for small capital improvements, thereby avoiding the need to issue bonds. The Fund cannot be returned to the ratepayers; in fact, the law clearly limits the use of the Fund to " renewals in excess of ordinary repairs, extensions, reconstruction, enlargements and additions". This project appears to fit one or more of these statutory categories. The TMLP Manager controls the appropriation of the Fund for TMLP projects, and has the authority to allocate the fund without city approval, according to the testimony. (Tr. 7/28/82, pp.20-25). The TMLP Manager does need approval from the TMLP Commission on the 115 kV project, but the Commission has already discussed the issue and its approval is likely. (Tr. 7/28/82, p.25).

TMLP has allocated up to $3,403,000 to pay for this project by 1984 (Ex. 20, p. 10), which should cover anticipated costs.

B. Need for the Proposed Line and Substation

The Siting Council must determine that a utility proposal will provide "a necessary energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost", M.G.L. c. 164, sec. 69H.

The Plant's need for the new transmission line and substation is based on considerations of reliability and recent load growth in the City of Taunton. Use of the 115kV line rather than the 13.8 kV supply lines will dramatically reduce line losses, thus saving energy. This will be discussed in section C(4) below.

1. Reliability

The TMLP system should be designed to be able to continue to supply load with the loss of any single major component, which could be one of three 13.8 kV distribution circuits to the Whittenton area or one of the two 41 MVA transformers at the West Water Street substation. The TMLP thinks this single contingency reliability is important, as has the Council in past Council decisions, most recently in 6 DOMSC 33, Commonwealth Electric Occasional Supplement. At present, the TMLP system fails to meet this reliability criterion (See Ex. 21, p. 1; Ex. 16, pp. 8-15).

The immediate reliability concern is back-up for the three 13.8 kV circuits to the Whittenton area (2 G14.51, 2 G14.52 and G14.51). If a fault occurs during peak load conditions on one of these circuits, an outage will occur until a maintenance crew restores service (Tr. 4-30-81, p. 107). The duration of the outage will depend on the system load and on the time required to get a crew out to the problem.

The outage record (Ex. 5, last page) tells us that faults on the three circuits serving the Whittenton area are frequent. With the presently measured peak loads, the Whittenton area has no redundant capability for the 13.8 kV distribution circuits. Thus, additional transmission capacity is needed.

The TMLP has presented evidence that construction of the proposed 115 kV line and substation will solve the reliability problem. The three existing 13.8 kV lines can serve as back-up for the new line, thereby providing redundant capacity for the Whittenton area. In addition, the 115 kV plan will improve voltage levels and voltage regulation in the Northern Service Territory, and will reduce the loading on the 13 kV supply circuits to the West Water Street Generating Station (Ex. 16, pp. 2-4).

2. Load Growth

The TMLP bases its projection of load growth in the Whittenton service territory on development of the Myles Standish Industrial Park and on general load growth in the Whittenton area.

The TMLP, through its witness, Mr. William McAloon, President of the Taunton Development Corporation (TDC), provided a history of and the prospects for the Myles Standish Industrial Park. The Park is a 437-acre site acquired from the Commonwealth in 1974 and deeded to the City of Taunton for the purpose of industrial development. Located in the northwest section of Taunton between Routes 140 on the west side and I-495 (under construction) on the northeast side, the Park has access to a permanent line of Penn-Central Railroad (Ex. 10).

The Industrial Park is a priority project in the overall Economic Development Plan (OEDP) for the Southeast Regional Planning and Development District (Tr. 4/30/81, p. 50, and Ex. 14, 15). The Park is expected to accomodate manufacturing, distribution, warehousing and high technology industries, some of which are already in the Norton-Taunton-Raynham area. The City of Taunton evidently welcomes these types of industries; Mayor Joseph L. Amaral stated "the development of Myles Standish Industrial Park has top priority by my administration for the future growth and development of the City." (Ex. 13).

The TMLP estimates that the Park has the potential to provide 4 to 6 thousand jobs and a $46-56 million payroll (Ex. 9). The present tenants, Boyden Plastics and Water Associates, employ over 500 persons (Tr. 4/30/81, p. 18; Ex. 14). Development of the Park would benefit the citizens of Taunton by increasing the tax base and by generating income.

Employees of industries in the Park could come from a number of places, including Fall River, New Bedford, Middleborough, Brockton, the Attleboros, Franklin and Milford, Providence-Pawtucket, and the southern fringe of the Boston Metropolitan Area, as well as Taunton's service area. Within a 20-mile radius of Taunton, the labor force numbers between 90 and 360 thousand (Tr. 4/30/81, p. 44). The region's OEDP (Ex. 15, pp. 38-41) offers evidence that Southeastern Massachusetts has a suitable and available labor force for the types of industries that would be likely tenants in the Park.

The Park is being developed in four phases of approximately 90 saleable acres per phase.

Phase I was funded through a $1,700,000 50-50 grant from the Economic Development Administration (EDA) and the City of Taunton. The grant paid for installation of sewer services, water systems, the road network and underground street lighting. In addition, the Taunton Development Corporation (TDC) supplemented EDA money with cash from early sales of land to pay for a looped water system and a 9,000 foot rail spur. All of these services have been designed in such a way as to serve the complete Park.

Waters Associates of Milford, a high tech industry, and Boyden Plastics (a division of Parker Brothers) have purchased between them 43 acres of land in Phase I. Both currently operate plants in the Park. These two tenants require a total of 1.5 MW peak demand for electricity. Waters Associates recently increased its building space from 12,000 sq. ft. to 32,000 sq. ft.; Parker Brothers plans to double its building space over the next four years. This expansion will increase electricity demand by 770 kW. (Ex. 18, p.9).

Phase II is being funded by a $1.64 million EDA grant and about $760,000 from the TDC. Work on the sewer, water, railroad, road network and underground lighting systems for the Park, and on the 2.1 million-gallon stand pipe storage water tank for emergency fireflow is essentially complete (Ex. 17, p.3). The land was first offered for sale in early 1982.

Pepsi-Cola Inc. has purchased a 7.5 acre site in Phase II for a warehouse facility, has purchased an 8 acre site in Phase I with rail access, and has interest in purchasing 5.5 more acres. In addition, a printing company is in the process of negotiating a purchase-and-sale agreement for land to hold a 21,000 sq. ft. building. Construction of these facilities will increase demand by an additional 350 kW (Ex. 18, p. 9; Ex. 17, p. 3).

Funding and development of Phases III and IV will depend on getting enough cash from the sales of land in Phases I and II. The TMLP expects that future federal or state funding will not be needed and did not indicate whether any would be available.

According to Mr. McAloon, the major catalyst to development in the Industrial Park is the completion of I-495; in particular the Bay Street interchange that directly connects with Myles Standish Boulevard (See map, Ex. 8). I-495 will link the Industrial Park with the interstate highway system and provide convenient access to Logan International Airport via Route 24. The completion date of I-495 is the fall of 1982 (Tr. 7-28-82, p. 29).

The lack of a reliable transmission system to the Park has a negative impact on the attractiveness of Park land to industrial customers. The proposed 115 kV line would remedy this by providing reliable service to the Park. It would also be capable of handling future load increases as they occur.

The TMLP also offered evidence on local system load growth. Mr. Michael Horrigan, TMLP engineer, testified that with the proposed impact of the Industrial Park, the number of home starts in Taunton would increase and the Whittenton area would experience approximately 3 percent load growth (Tr. 4-30-81, p. 99). He submitted a list of expected new customers in the area outside the Park from which he predicted a load increase of 1078 kW over the next one to two years (Ex. 18, p. 7).

Thus, though TMLP has not submitted a demand forecast since 1979, it has projected load growth of 2.2 MW over the next few years in the area served by the proposed 115 kV line. TMLP already lacks a single reliability contingency in this area. Unless the 115 kV line and substation are built, further load growth will increase the probability, frequency and cost of outages in this area while decreasing the quality of service to TMLP customers.

C. Alternatives

This section discusses various routes for construction of the proposed 115 kV power supply extension to the Whittenton area and alternative substation sites. It also discusses other transmission strategies: supplying the Whittenton area with 69 kV circuits or with more 13.8 kV circuits and transformers as load grows. The cost estimates discussed in this section are those provided by Taunton in its 1981 testimony.

1. Alternative Routes for the 115 kV Line

The Taunton Municipal Light Plant proposal is known as the "East"

Route. The TMLP describes two alternate routes in Ex. 1, pp. 7-9. The "Central" route would make use of an existing utility right-of-way and is a more direct route to the Whittenton area from the West Water Street substation. This 115 kV line would go underground at Somerset Avenue and substantially follow an existing 13.8 kV underground cable for 1.4 miles north to Winthrop Street. It would then go overhead and parallel an existing 13.8 kV overhead line along Cobb Creek and through Crapo Bog. This alternative route is 3.3 miles long as compared to 3.7 miles long for the proposed route. The section of the existing right-of-way that is above ground would probably need to be widened. The total estimated cost of the "Central"Route line is $1,026,000, greater than the projected cost of the proposed "East" Route line, which is $690,000. This cost differential is largely due to the underground cable. Because costs of the "Central" Route would be higher, and because it is likely that some construction in wetlands would be necessary, the Council finds the proposed route to be superior.

The "West" Route described by TMLP would commit substantial stretches of wetlands to a permanent right-of-way utility easement. Since this route is not developed, and access by road to some portions of it is not presently feasible, substantial land acquisition and environmental costs would have to be added to the estimated price of $400,000. In addition, two new homes now block this route. The Council finds the proposed route to be superior to the "West" Route.

2. <u>Alternative Substation Sites</u>

One alternative substation site is the existing Whittenton substation (Ex. 1, p. 11). Expansion at this site would encroach on a river bank, cause runoff problems, and encroach upon existing roads or private residential property (Ex. 1, p. 11). The total estimated cost of a substation located on this site is $1,475,000, considerably more than the estimated cost of the proposed substation, which is $1,178,000, (Ex. 1, p. 12). For these reasons, the Council finds the proposed substation site superior to expansion at the Whittenton site.

Building the substation at the Attleborough Junction site would cost the same as the proposed Whittenton Junction substation. Both sites are in lowland areas (not wetlands), and any environmental problems could be mitigated (Ex. 1, p. 10). However, the Attleborough Junction site is 4,000 feet closer to the Park. For that reason it would require substantially more initial cost for longer 115 kV circuits and for 13.8 kV distribution circuits back to the West Brittania Street transportation corridor to back up existing load outside the Park. The Council finds that the proposed Whittenton Junction Substation location is superior to the Attleborough Junction site because it would minimize TMLP's overall cost for 115 kV power supply to the Whittenton area of Taunton.

3. <u>69 kV Transmission Line Alternative</u>

The alternative of building a 69-kV transmission line and appropriate substations would be more expensive than the proposed plan because two additional transformers would be needed; one to lower the voltage from the existing West Water Street 115 kV line to 69 kV, and one to lower the voltage from 69 kV to the distribution line voltage of 13.8 kV (Ex. 5, p. 9). A 69 kV line would also have greater line losses than a 115 kV line. Therefore, the Council finds the proposed plan to be superior to any 69 kV transmission line alternative.

4. 13.8 kV Transmission Line Alternative

At the request of the Staff, TMLP analyzed construction of a fourth 13.8 kV transmission line as an alternative. TMLP examined a 3.43 mile long 13.8 kV line that would run from the West Water Street Substation to the existing Whittenton substation. This 13.8 kV plan would cost only $380,000 (by 1983) and would not require construction of a new substation.

However, the TMLP presented evidence that the 13 kV plan would be less reliable than the 115 kV plan. TMLP's transmission line expert testified that "I cannot technically support the 13 kV plan... The 13 kV plan does not meet typical levels of industry reliability and provides a level of reliability inferior to the 115 kV plan and not acceptable to the Taunton Municipal Lighting Plant (Ex. 16, pp. 1-2)." The fourth 13 kV line would only be a stopgap measure; further load growth at Myles Standish Industrial Park would require construction of additional 13.8 kV lines and substations to maintain reliable service (Ex. 16, p. 8). Moreover, a fourth 13.8 kV line would not provide a firm supply to the West Water Street Generating Station (Ex. 16, p. 3).

TMLP also presented evidence that the 13 kV plan would be more expensive than the 115 kV plan because of the higher line losses associated with lower voltage lines. TMLP projected additional line losses of 1450 MWh per year, or $77,000 per year, associated with the 13 kV plan (Ex. 16, Ex. PT5). Over the life of the transmission line, the savings from reduced line losses outweigh the difference in capital cost, and the 115 kV plan has a greater net present value than the 13.8 kV plan. This conclusion is not sensitive to changes in the discount rate or in construction or maintenance cost escalation rates.

Therefore, the Council finds the 115 kV plan to be superior to the 13.8 kV plan on the bases of better reliability and lower cost.

D. Environmental Impact

The Siting Council must determine that proposed facilities will have "minimum impact on the environment", M.G.L. c. 164, sec. 69H.

Almost all of the route for the proposed 115 kV transmission line is alongside a railroad track. The proposed line would not cross any water resources. The TMLP would use selective clearing and feathering techniques on the route to leave as much natural vegetation as line clearance requirements would allow. No evidence as to potential interference with television reception was introduced in the hearing. Michael Horrigan described potential interference problems at the informational hearing (Ex. 2, pp. 79-80) and stated that they can be completely eliminated.

One resident who lives nearby does not want to see a new substation so close (1/4 mile away), but clearing at the proposed Whittenton Junction Substation would be limited to the actual substation site, and sufficient vegetation would be allowed to remain to screen the completed structure. The design is low profile.

The fact that the intervention by the 29 petitioners was dropped seems to indicate that the most affected and interested citizens no longer have substantial objections to the TMLP's proposal.

III. FINDINGS OF FACT

1. The TMLP has established that its proposed 115 kV transmission line and substation are needed for system reliability and to meet projected load increases at the Myles Standish Industrial Park.

2. The TMLP's proposal is the "least cost" method for resolving its short and long-term reliability concerns.

3. The TMLP has demonstrated, to the satisfaction of the Council, that the proposed route, site and transmission voltage are superior to any alternative route, site or transmission voltage upon which evidence was taken.

4. The TMLP has demonstrated to the satisfaction of the Council, under G.L. c. 30 sec. 61 and the Council's own mandate, that the environmental impacts associated with the TMLP proposal are minimal, and that the proposal incorporates all reasonably necessary and feasible measures to minimize environmental impacts.

IV. RATIONALE FOR DECISION

The Taunton Municipal Lighting Plant has proved that the proposed 115 kV transmission line and associated substation will provide a necessary power supply with a minimum impact on the environment at the lowest possible cost, G.L. c. 164 sec. 69J. The supply system to the Whittenton area of Taunton does not now meet the "single contingency" reliability criteria which the Council has deemed appropriate in several other proceedings. Projected load growth in the Myles Standish Industrial Park and in the Whittenton area makes the reliability concern even more pressing. TMLP's 115 kV transmission line will provide "single contingency" reliability, and is superior to any 13.8 kV or 69 kV line alternative. In addition, use of the 115 kV line, coupled with abandonment of the three existing 13.8 kV supply lines except for backup, will dramatically reduce line losses.

At the first hearing, in July of 1981, the TMLP emphasized load growth in the Myles Standish Industrial Park, and future reliability problems, as justification for its construction proposal. The staff felt that the evidence offered was insufficient to justify a capital expenditure of nearly two million dollars, particularly given the absence of a reliable system forecast. By the time of the second hearing, in July of 1982, Taunton had experienced enough load growth in the industrial park and in the Whittenton area to have lost single contingency reliability. It was also able to present a far more convincing argument that construction was economically justified. Taunton explained that it could use funds from a depreciation account, rather than issue bonds, to finance construction. With virtually interest-free financing, coupled with substantial savings associated with reduction of line losses, the proposal will benefit Taunton's ratepayers not only long-term (life of the transmission line), but short-term as well.

The Council remains concerned about the lack of a recent, reliable forecast. The TMLP has made considerable progress. Its "Compliance Plan", filed in May, 1982, promises substantial improvement in the way Taunton projects demand for electricity. Michael J. Horrigan, Taunton's Senior Electrical Engineer, expects to be able to submit the new filing in October, 1982 (Tr. 7-28-82, p. 32).

Mr. Horrigan also said that construction would start in the Spring or Summer of 1983 (Tr. 7-28-82, p. 30). By requiring a new filing, covering the years 1982-1992, before construction can begin, the Council will ensure that Taunton's forecasting will continue to progress, without delaying the needed facilities. The Council does expect that

Taunton will make every effort to file a good forecast as soon as possible.

In the interim, the Council encourages the TMLP to proceed with design work, and specification and ordering of equipment, so that the "lead time" associated with its construction proposal will not be substantially increased.

V. ORDER

The Taunton Municipal Lighting Plant may begin to design, order equipment for, and commence local licensing of, its proposed new 115 kV transmission line and substation in the City of Taunton. TMLP may commence construction as soon as it submits its next filing, the Second Long-Range Forecast and First Supplement thereto, covering the years 1982-1992, in conformity with its "Compliance Plan".

Robert T. Smart Jr., Esq.
Hearing Officer

This Decision and Order was approved unanimously by the Energy Facilities Siting Council at its meeting on August 16, 1982 by those members present and voting.

Voting in favor: Margaret N. St. Clair, Secretary of Energy Resources; Sandra Uyterhoeven, designee of the Secretary of Environmental Affairs; Richard Pierce, designee of the Secretary of Consumer Affairs; Noel Simpson, designee of the Secretary of Economic Affairs; Harit Majmudar Ph. D, Public Electricity Member.

Ineligible to Vote: Charles Corkin II, Esq.; Public Oil Member.

Margaret N. St. Clair
Chairperson

Dated at Boston this 27th day of August, 1982.

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of the Westfield Gas and Electric Light Department for Approval of its Second Long-Range Forecast of Gas Needs	EFSC No. 81-26

FINAL DECISION AND ORDER

Lawrence W. Plitch, Esq.
Hearing Officer

FINAL DECISION AND ORDER

This decision Approves the Department's Second Long-Range Forecast, subject to the Conditions noted herein.

The first section contains an introduction and a procedural history. The second section describes and reviews the Department's sendout forecast. The third section discusses and analyzes Westfield's supply forecast, including both a review of the Department's contingency planning and the piping failure experienced by Westfield last winter. Both of these principal sections are framed by the Conditions set out by the Council in Westfield's most recent approval, EFSC No. 80-26. The fourth and final section contains the Order and Conditions to the Department's next filing.

I. Introduction

Westfield Gas and Electric Light Department is a municipal utility serving exclusively the homes and businesses of the City of Westfield (estimated population 35,000). In terms of annual gas sendout, Westfield ranks 10th among the Commonwealth's 14 gas utilities. Its customers and usage by class are broken down as follows:

Actual 1980-1981

	No. of Customers	% of Total	Sendout (MCF)	% of Total
Residential Heating	4099	65.6	484,444	35.4
Residential Non-heating	1631	26.1	59,850	4.4
Commercial, Firm	484	7.7	319,685	23.3
Industrial	21	.3	137,223	10.0
Municipal	18	.3	19,828	1.4
Sales for Resale	-	-	136,413	10.0
Company Use and Unaccounted For	-	-	211,701	15.5
	6253	100.0	1,369,144	100.0

Westfield filed its forecast with the Council on November 24, 1981. Data requests were sent out by the staff on April 22, 1982. Responses were received on June 1, 1982. Follow-up questions were posed to and answered by Dan Golubek, Manager of the Department, during telephone conversations in July, 1982. Official notice of this adjudication was published in the Springfield Daily News on May 10, 17 and 24, 1982 and in the Westfield Evening News on May 10, June 7 and 14, 1982. Insofar as no petitions to intervene were received and no new facilities are being proposed, this forecast was adjudicated without holding formal hearings.

II. Forecast of Sendout Requirements

A. Design Year

Condition No. 1 to the last Westfield Decision and Order ordered the Department to:

> complete the re-evaluation of its method for deriving design degree days and incorporate the result of its re-evaluation in its next filing, making all appropriate changes over the forecast period.

In its previous filing, Westfield used a design year of 7631 degree days. This was based on a combination of the coldest heating season in the past 100 years and the coldest non-heating season of the past 100 years. In the present filing, Westfield has chosen a methodology that is more in line with common industry practices. As explained on pages 1 and 2 of the forecast and in telephone conversations with the Hearing Officer, the new methodology reflects a design year equal to the coldest split year in the past ten years, or 6954 degree days. The design day has been increased to 69 DD to account for the record degree day recorded during the most recent winter (as of the filing), 1980-81. The Council is satisfied that this condition has been met.

B. Conservation

Condition No. 3 to the most recent Decision and Order required the Department to:

> in its next filing, address the impacts of conservation in more detail, including, but not limited to, consideration of factors tending to influence conservation, how these factors are likely to affect the forecast of sendout requirements, and the bases for any judgements made and conclusions drawn.

In the present forecast, the Department has given a detailed description of the several strategies it has adopted for promoting conservation. These include promotional literature, bill stuffers, funding a city energy coordinator and participating in the Mass SAVE program. The Department has recognized that lower base levels per customer and decreasing degree day factors are likely (as noted in the forecast narrative (p. 4)). However, the following table shows that this recognition has only been carried through to the forecast of the two residential classes and the commercial class.

MCF per customer	Actual 80-81	Forecast Projections 81-82	82-83	83-84	84-85	85-86	Average Annual Change in Usage
Resid. Heating							
-Base Use	.1230	.1064	.1032	.1001	.0971	.0942	- 5%
-Htg. Use	.0110	.0119	.0115	.0112	.0109	.0106	-0.8%
-Class Totals	119.5*	115.8	112.0	106.8	105.9	102.9	-2.9%
Resid. Non-Htg.	36.70	37.24	37.24	37.24	37.24	37.24	+ .3%
Commercial Firm	646.7*	646.4	646.1	645.8	645.6	645.3	- .05%
Industrial Firm	6598*	6598	6598	6598	6598	6598	0%

* Normalized

By contrast, the industrial class table (G-3(B)) does not reflect a reduction in either the usage per customer or the number of customers. This is at a time when many people (including the management of Westfield) are predicting that the substantial gas price increases that are expected in the next few years will have the greatest impact on the amount of gas sold to the industrial class. (Westfield's industrial class presently consumes over 10% of the Department's annual sendout). As such, the Council encourages the Department to follow through with its suggestion that an attempt be made to quantify and understand the potential that exists for sendout reductions in the industrial class. (See Section III. B.).

C. <u>Conversion Standards</u>

In Condition No. 4, the Department was ordered to:

> supply the following data with respect to customer requests for conversion to gas heating:
> a) Does the Department evaluate the thermal integrity of the house before converting the customer's heating system? If so, how; if not, why not?
> b) Does the Department have or recommend any insulation standards? If so, what are the standards; if not, why not?
> c) Provide and document an estimate of what percentage of customers installing new gas heating units (new housing, conversions or replacements) install high efficiency burners as opposed to average efficiency burners.

Through telephone conversations with the Hearing Officer, Mr. Golubek, the Department's General Manager, stated that the Department does do some conversion-related evaluations. However, the limited staff and resources available to Westfield preclude more sophisticated kinds of analyses. Presently, the Department takes the average base factors and heating use factors into account when considering conversion requests, then modifies those numbers by factors reflecting the age and condition of the homes. The insulation standards recommended are those of the Mass SAVE program.

There is no documentation of what percentage of new heating unit customers install high-efficiency burners. However, Mr. Golubek does estimate that the percentage is "very high". This response satisfies Condition No. 4 of the Decision and Order No. 80-26 and has generated no new Conditions.

III. Supply Projections

A. Tennessee Security

The second Condition to the most recent Westfield Decision and Order required the Department to:

> discuss and document, in its next filing, its supply availability situation from November 1, 1983 through the end of the forecast period. In particular, the Department should document its contention that additional supplies will be available from Tennessee to meet projected requirements. In addition, the Department should report how its requirements would be met if the increase from Tennessee is not forthcoming.

Westfield's gas supply consists principally of four sources of gas. As the following table shows, the Department is dependent upon Tennessee Gas Pipeline Company (Tennessee) for the greatest portion of its supplies, both for annual and peak day sendout:

	Estimated 1981-1982				Actual 1980-1981	
	Annual Normal Firm Sendout (MCF)	% of Total	Total Annual Take (MCF)	% of Total	Peak Day Sendout (MCF)	% of Total
Tennessee (G-6)	1,091,349	98.6	1,106,814	94.7	4618	51.1
Bay State (vaporized LNG thru Interc.)	5,135	.5	23,500	2.0	780	8.6
Bay State (purch. as LNG)	9,135	.8	27,500	2.4	3635	40.3
Propane (from storage)	1,141	.1	10,778	.9	0	
Totals	1,106,760	100	1,168,592	100	9033	100

Second in importance to Westfield's supply security in 1980-81 was its purchases of gas from Bay State Gas Company. Westfield purchased almost all of its supplemental supplies from this one source, either as vaporized LNG through their interconnection or as LNG, delivered by truck to Westfield's LNG satellite facility. Although propane was expected to supply .1% of the Department's sendout in 1981-1982, this amount was to be taken out of existing storage and does not result from any existing supply contracts.

The second condition to Westfield's most recent forecast approval reflected a particular concern of the Council that the projected additional supplies from Tennessee might not materialize. As of the time of the previous filing's review, the Department had not secured under contract enough gas to supply the expected sendout requirements of its customers for the period after November 1, 1982. As a result, the previous forecast was approved only through October 31, 1983.

In the present forecast, Westfield has included a revised contract with Tennessee Gas Pipeline Company that evidences a firm supply commitment through November, 2000. As such, the second Condition to the Council's most recent forecast approval has been met. However, the future ability of the Department to meet its sendout projection remains a problem. The present filing includes no documented assurances that anticipated amounts of LNG, expected to increase 330% (over 1980-81 peak day usage) during the forecast period, will be available. In addition, the Bay State Gas Company interconnect contract included in the present filing was to have expired March 31, 1982, rendering insecure what was projected to amount to 13.2% of the forecasted sendout for the '81-'82 peak day. Thus, it is hereby made a specific Condition to this Decision and Order that Westfield provide by September 15, 1982, either contractual documentation of all anticipated supplemental gas supplies for the next-filed forecast period, i.e., from November 1, 1982 - October 31, 1987, or a detailed discussion of its contingency plans for supplying its system's needs, absent such contracts.

B. Piping Failure Incident

At 4:48 A.M. on January 22, 1982, a 4" natural gas pipeline, owned and operated by Westfield Gas and Electric Light Department, ruptured releasing approximately 165 MCF of gas into the atmosphere. The pipeline that ruptured is one of two prime feeders to Westfield's distribution system. The point of failure was at the confluence of the primary natural gas supply from Tennessee Gas Pipeline Company and the supplementary gas supply from Westfield's LNG plant contiguous to the gate station.

Although there were no fatalities or injuries to employees, gas consumers or the general public as a result of the accident, the resulting radical drop in distribution system pressures resulted in an outage to approximately 856 gas customers. The duration of the emergency from the time of the rupture to the restoration of normal service to all affected customers was 15 3/4 hours.

Paul Johnson Associates were hired to investigate the accident. Their resulting report, published in March of 1982, concludes that the accident was caused by "sustained low ambient temperatures at and prior to the time of failure that caused the pipe material to undergo a ductile-to-brittle transition, and which, under the combined influence of bending and torsional stresses initiated a brittle-type fracture". The report also concludes that "prompt action" was taken to bring the escaping gas under control, and repairs were made "in an orderly, safe and expeditious manner."

The Council has reviewed the Paul Johnson Associates report. Although pipeline safety is not per se jurisdictional to the Council, our mandate to ensure an adequate supply of energy for the citizens of the Commonwealth certainly includes our right to review pipeline failings that cause significant interruptions in that supply. As such, the Council urges the Department to fully consider the series of recommendations on pages 31-32 of that study.

C. Crisis Planning

The fifth and final Condition of the previous Decision and Order required the Department to:

> in its next filing, describe the criteria it uses to define and plan for periods of extreme cold weather, i.e., periods longer than a day but shorter than a heating seasons. The Company should explain how it plans to meet sendout requirements during such a period of extreme weather during each of the forecast years, including a discussion of the underlying assumptions made about the availability and delivery of supplemental gas. Finally, the Company should discuss how its planning criteria performed in relation to actual 1980-81 winter weather.

Although this Condition was not addressed in the submitted forecast, the Department's General Manager, Dan Golubek did respond to this Condition in the course of a telephone conversation in July, 1982. Mr. Golubek's response to this Condition was twofold. First, he indicated a sophisticated awareness of the several factors that influence the Department's ability to meet future unanticipated medium term supply problems. The Department is constantly monitoring the various load levels, their type and quantity to see who might be willing or able to curtail usage. The future load growth potential for the City is being studied for its implications vis-a-vis possible peak period supply shortages. The result is a well developed, albeit informal,planning approach for assessing and monitoring changes that affect supply crisis response capability. However, the second aspect of Mr.Golubek's response reflected the current assessment that has resulted from this monitoring process. As the Departments supply/demand projections presently stand, there are no shortfalls anticipated for the forecast period, assuming "normal" design conditions. However, in the event of a repeat of the type of cold snap that was experienced in 1980-81 (and which was the basis for the concerns of Condition No. 5), disruptions to customers might conceivably occur. This prospect results not from an inadequate sendout capacity but rather from the region's dependence on gas trucking systems. Under a reasonable gas crisis scenario, several companies would be dependent on the same trucking firms as Westfield. In fact, this problem helped aggravate the crisis in 1980-1981. Consequently, Westfield has been considering and pursuing a wide variety of supply options. Among the steps that Westfield has taken are:

(1) The Department has entered into negotiations with Bay State Gas Company to increase its yearly levels of purchase from this source to 96,000 MCF. Preliminary indications are positive.

(2) The Department is actively studying the feasibility of expanding the capacity of its propane/air plant.

(3) The Department has hired Paul Johnson Associates to evaluate several supply options, including the possibility of expanding Westfield's LNG storage capacity.

These various options are driven by reasonable demand forecasts, given the historical data and consumption trends. However, the management of the Westfield Gas and Electric Light Department is also aware of the likelihood of significant price increases resulting from natural gas deregulation during the next few years. Although the exact effect of these price increases is difficult to predict, Mr. Golubek notes that he already has seen a loss of industrial customers by other gas companies as the gas/oil price differential has evaporated. Consequently, Mr. Golubek feels strongly that the Department must attempt to make some predictions as to which of their customers might switch fuels and at what price. In this way, Westfield seems intent upon not entering into costly new supply arrangements that might prove unnecessary in two or three years' time.

The Council is satisfied that this Condition has been met and commends the Department's obvious commitment to securing an adequate supply for its customers at a minimum cost and looks forward to the results of the Department's various studies.

IV. Conclusions

The Council hereby APPROVES the Westfield Gas and Electric Light Department's Second Long-Range forecast of Gas Needs subject to the following Condition:

(1) That the Department provide by September 15, 1982, either contractual documentation of all anticipated supplemental gas supplies for the next-filed forecast period, i.e., from November 1, 1982 - October 31, 1987, or a detailed discussion of its contingency plans for supplying its system's needs, absent such contracts.

Lawrence W. Plitch, Esq.
Hearing Officer

This Decision was approved unanimously by the Energy Facilities Siting Council at its meeting on August 16, 1982, by those memebers present and voting.

Voting in favor: Margaret St. Clair, Secretary of Energy Resources; Noel Simpson, designee of the Secretary of Economic Affairs; Sandra Uyterhoevan, designee of the Secretary of Environmental Affairs; Richard Pierce, designee of the Secretary of Consumer Affairs.

Ineligible to Vote: Harit Majmudar, Public Electric Member; Charles Corkin II, Esq., Public Oil Member.

Date

Margaret St. Clair
Chairperson

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Berkshire Gas for Approval of its Second Long-Range Forecast of Gas Needs and Requirements

EFSC No. 81-29

FINAL DECISION

Paul T. Gilrain, Esq.
Hearing Officer

On the Decision:

Margaret Keane
Senior Economist

I. INTRODUCTION AND HISTORY OF THE PROCEEDINGS

The Council hereby APPROVES the Second Long-Range Forecast of gas Needs and Requirements of the Berkshire Gas Company.

The Berkshire Gas Company ("Berkshire" or "The Company") is a Massachusetts corporation and is engaged in the business of distribution and sale at retail of gas in nineteen communities in Berkshire, Franklin, and Hampshire counties. The Company has approximately 26,000 customers. The Company filed its Second Long Range Forecast on December 30, 1981. The Council then ordered publication of a notice of public hearing and adjudicatory proceedings in newspapers of general circulation within the service area of the Company. The New England Fuel Institute (NEFI), a trade organization representing over 1,000 independent fuel oil dealers, petitioned to intervene in the proceeding and was granted status as a "participating person" under EFSC rule 15.3. NEFI did not participate in the review of the Berkshire forecast beyond its petition to intervene. One technical session was held at the Company headquarters and one set of discovery was sent out and answered.

No party requested a hearing and the record was closed on August 23rd, 1982.

II. Previous Conditions

The Council's decision in the review of the Company's Fourth Supplement imposed five conditions. The conditions and the Company's responses are as follows:

1) That in its next filing the Company illustrates how the forecast of normal and design season sendout and per day sendout on Table G-1 through G-5 were calculated. The Company should also list all projected customers use factors.

2) That in its next filing, the Company discuss historical trends and judgements used as bases for projections of customer use factors.

The Company has fully complied with conditions 1 and 2, regarding documentation of Table G-1 through G-5 and discussion of historical trends and judgements. These aspects of the forecast will be discussed in Section III, sendout.

3) That in its next filing the Company address the issue of conservation in more detail, including, but not limited to, considerations of factors which influence conservation, how these factors are likely to affect the forecast of sendout requirements, how the Company's conservation efforts can be improved, and the bases for any conclusions drawn.

The issue of conservation, Condition 3, was addressed both within the context of the forecast and during the course of discovery. The forecast states, "Berkshire anticipates a continuation of conservation by all classes of customers... the primary consideration for continued conservation is the increasing price of all energy sources. While energy costs continue to increase, expenditures for conservation are anticipated to do the same." The Company expects 5% of its customers to be audited annually through the Mass Save audit programs and weighs this data in its forecasting efforts.

4) That in its next filing the Company addresses in detail its contingency plans should the supply of Boundary Gas be delayed or denied.

In the current forecast, the Company is anticipating deliveries from the Boundary project for the winter of 1984-85. Over the past year, the economics of imported gas have changed such that an additional concern of the Council is whether the Company will be able to market the imported gas. In response to EFSC 81-29 Information Request 12, the Company stated, "Berkshire is confident of its ability to market the additional volumes when it becomes available. Additionally if such marketing ability should change, Berkshire would be in a position to use Boundary volumes to replace various supplemental supplies." The Company further states in the forecast, "The Boundary Gas project would allow the Company to expand its customer base at an increased rate by improving the peak day sendout capabilities." Independent review of the status of the Boundary project by Council staff supports the reasonability of this 1984-85 projection.

5) That in its next filing the Company analyze the costs and benefits (from the customer's perspective) of converting from oil to gas heat. The Company should identify the factors which affect this cost/benefit equation (e.g. age or efficiency of existing oil burners, efficiency of new gas burners, insulation levels, cost of conversion), examine the customer's payback under different assumptions regarding the price of heating oil and the price of gas to the Company's

customers and offer any documentation available regarding the impact in the Company's service territory of gas price decontrol.

Condition 5, pertaining to costs and benefits of converting from oil to gas heat, is also addressed in the forecast. The Company states that natural gas currently enjoys a 40% price advantage in its service territory and continues to say, "While the differential cannot be anticipated to remain as great in the future, it is anticipated to maintain a price advantage." Berkshire lists factors which it considers to be other price advantages associated with gas use. These include: lower costs for installation of gas burners as opposed to oil burners, elimination of boiler cleaning expenses, fewer service expenses and reduction in cost of electricity due to the fact that electric vaporization equipment is unnecessary. From 1978-79 to 1981-82 the Company received 4400 requests for conversion and added 3479 additional heating customers (Information Response 81-29, No. 17). Berkshire states that, "even with gas price decontrol, residential gas heating customers will benefit with lower costs compared to No. 2 fuel oil for the forecast period."[1]

1 See: "Natural Gas Still A Bargain In Spite of Rate Increases", Platt's Oilgram Price Report, August 31, 1982.

III. Sendout Methodology

A. Normal Year

A "normal year" is defined as a year that is neither warmer nor colder than average. Berkshire analyzed the past twenty years of Degree Day Data to arrive at the average number of Degree Days for both the heating and Non-heating seasons. Thus, the company uses a Normal Year of 7467 Degree Days.

Base Use is calculated by multiplying base factor (the average of July and August use) by number of customers by 12 months. Heat sensitive usage is forecast by multiplying use per degree day by number of degree days by number of customers. (See Figure 1)

B. Design Year

A "design year" is defined as the coldest year for which a Company plans to meet its firm customer requirements. The Company used a design year of 8140 Degree Days, the coldest year experienced during a 20 year period.

Design year sendout was calculated in the following way. Base sendout was assumed to be the same in both normal and design years. As seen on Table DD, design degree days were approximately 9% greater than normal for the total split year. (See Figure 1 for example)

C. Peak Day

A "peak day" is the coldest day that is likely to occur during a twelve month period. The company uses a peak day of 74 degree days which is colder by 12.5% and one standard deviation from the average of the coldest day in each of the past 20 years.

TABLE 1

Berkshire Gas Company

Berkshire gives the following example of a calculation for normal year and design year sendout:

For 1981-82, Residential Heat Class:

Base use: 12 mos [(July MCF + August MCF) / 2]/Average No. customers
12 mos [(45,090 + 41,019) / 2]/13,800 = 37.4 MCF

Use/degree day: $\left[\frac{\text{12 mos usage}}{\text{Avg. No. customers}} - \text{Base Use}\right]$ /12 mos D.D.

$\left[\frac{\text{1,987,062 MCF}}{\text{13,800}} - 37.4\right]$ /7047 D.D.

= .015 DD

Base Use = 37.4 MCF X 13,800 = 516 MMCF	516 MMCF
Heat Sensitive = .015 MCF X 7467 DD X 13,800 =	1,546 MMCF
	2,062 MMCF[3]

Non-Heating Season (April 1 - October 31)

7/12 X 516 MMCF =	301 MMCF
.015 X 1,827 DD X 13,800 =	378 MMCF
	679 MMCF

Heating Season (November 1 - March 31)

5/12 X 516 MMCF =	215 MMCF
.015 X 5,640 DD X 13,800 =	1,168 MMCF
	1,383 MMCF

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

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

3. Source: Forecast Appendices

D. Customer Projections

Berkshire's projections for number of customers are based on information provided by the Company's marketing department and are essentially judgemental.

The Company expects an increase in the residential with heat category resulting from oil to gas conversions by new customers and by existing non-heating customers. Nominal growth was projected in the commercial and commercial heat categories, assuming that new customers will cancel out the effect of those going out of business. Minimal growth is expected in the industrial class. Company projections are shown graphically on Figures 2 and 3.

While most gas companies have traditionally considered themselves supply constrained and based their sales projections on that premise, such assumptions must now be substantiated. Given the advent of decontrol and the resulting competition of No. 2 and No. 6 fuel oil particularly in the dual fuel market, a loss in market share appears possible. While the Council realizes that the Company does have a substantial amount of flexibility within the context of its supply agreements, the Council fully expects further documentation of such projections in all future filings.

E. Application of Review Criterion to Sendout Forecast

On the whole, the Council is pleased with the Company's sendout methodology. While documentation of customer projections is lacking, the rest of the Company's methodology is clearly stated and well documented. The appendices provided useful information on derivation of customer use factors and sales equations. The Company is to be commended for presenting a reviewable forecast.

The Council further believes that the Company's methodology is appropriate for its system. Separation of heating base use factors and sendout forecasts disaggregated by customer class add to the reliability of Berkshire's forecast.

The Company is urged to continue its progress in developing its forecast.

IV. Supply Contract & Facilities

1. Pipeline Gas

Berkshire is a customer of the Tennessee Gas Pipeline Company and has contracted for 5,256,650 MCF annually with an MDQ of 19,948 MCF through November 1, 2000.

The Company contracts with Penn. York Energy Corp. for 260,000 MCF of storage, with firm delivery as a result of Tennessee Gas Pipeline facility modifications completed in February 1982. The FERC has approved an additional 140,000 MCF of Penn. York Storage; however the Company has stated that it does not expect firm delivery in the near future. (Response to EFSC Information Request 81-29, No. 18). These contracts extend until 1995. The Company also has a contract for storage service with Consolidated through 1990 for 140,000 MCF with 1,273 MCF firm transportation.

2. Liquefied Natural Gas

The Company purchases liquefied natural gas (hereinafter LNG) from Distrigas of Massachusetts under a contract that extends until 1997. Berkshire's contract with DOMAC stipulates an annual quantity of 290,000 MCF with a maximum daily quantity of 1,300 MCF. The Company expects less than the contract quantities of 290 MMCF to be delivered and lists 255 MCF as total supply available in Table G-22.

As the Company does not expect Boundary Gas supplies to be on-line until winter 1984-85 it is currently formalizing a contract with Bay State Gas for additional LNG supplies. The Company plans to sign a 2 year contract for 4 MMCF/day, renewable through 1988. When these negotiations are finalized the Company's peak day LNG sendout capacity will be 5.3 MMCF/day as opposed to the 4.3 MMCF/day listed on Table G-23. The Council expects to be notified when this arrangement is finalized or notified of other contingency plans in the event it is not finalized.

3. Propane

The Company contracts with Warren Petroleum for 3,000,000 gallons (27.5 MMCF) of propane and with Commonwealth Propane Company for 1,000,000 gallons (91.74 MMCF). These contracts are renewed annually. Berkshire has Liquid Propane Air facilities in Pittsfield, Stockbridge, North Adams, Greenfield and Hatfield. These facilities have a combined maximum daily design capacity of 13.7 MMCF and a storage capacity of 51.5 MMCF. The Company also has storage facilities in Stockbridge and North Adams with capacities of 5.5 and 11.01 MMCF, respectively. These new facilities bring the Company's total propane storage capacity to 68.01 MMCF.

V. Comparison of Resources to Requirements

1. Normal Year

The Company expects to meet total sendout requirements during the forecast period under normal weather conditions as illustrated on Table G-22 in the forecast. (See Table 2) Pipeline gas from Tennessee is expected to provide 93% of the non-heating season load and approximately 88% of heating season load. This percentage will increase slightly when

TABLE 2

Berkshire Gas Company

Heating Season Supplies and Sendout

	1982-83		1985-86	
	Total Supply Available	Normal Firm Sendout	Total Supply Available	Normal Firm Sendout
PIPELINE				
CD	2606	2126	2606	1932
Storage	400	400	400	400
NON-PIPELINE				
Propane	140	100	120	80
Vaporized LNG Purchases*	255	255	255	255
FUTURE SOURCES				
Boundary Gas			302	302
TOTAL SUPPLY	3401	2957	3683	2969
DESIGN YEAR REQUIREMENTS	3095		3106	

* Berkshire is currently negotiating a contract with Bay State Gas for purchase of LNG. As it now stands, the contract would provide for 150 MMCF over the heating season, with an option to purchase an additional 50 MMCF. This would bring the total supply available to 3551 MMCF, excluding optional volumes.

Boundary Gas supplies become available. Propane, a small portion of total sendout, is put into storage (40 MMCF) during the non-heating season and constitutes approximately 4% of total heating season supply. LNG supplies provide approximately 5% of non-heating season load and 7.5% of heating season load. It is anticipated that Boundary Gas supplies, anticipated to come on-line for winter 84-85, will comprise 11% of non- heating supply and 7.5% of heating supply. The supplies outlined here appear satisfactory to ensure a reliable supply of gas to customers of Berkshire Gas during a normal winter.

2. Design Year

The record also indicates that the Company will have sufficient supply to meet the additional requirements expected to occur in a design year. As seen in the Company's G-22 tables, the Company's total available supply for split year 1982-83 is 5328 MMCF, with design year requirements of 4991 MMCF, leaving a 6% margin. It should also be noted that the Company's design year of 8140 DD is one of the highest in the Commonwealth.

3. Peak Day

The record, again, indicates that Berkshire will have more than adequate resources to meet forecasted Peak Day Sendout during the forecast period. The Company's G-23 table shows 42.9 MMCF available to meet peak day requirements of 37.9 MMCF in 1982-83. With additional Bay State supplies the total available supply is increased to 43.9 MMCF, leaving a margin of approximately 14% above peak day sendout requirements. Given the Company's relatively high peak day of 74 degree days, it would appear that the Company's supply planning is more than adequate to satisfy Council standards.

4. Cold Snap

A "cold snap" is a series of contiguous peak days, such as the two to three week period experienced during the winter 1980-81. Such periods represent particular planning problems for gas utilities different from meeting needs on one extremely cold peak day, or meeting the needs of an entire heating season. As mentioned infra at page 13, the Company has significantly more resources available than are required to meet its peak day requirements for a cold snap.

The Company's capability to meet a cold snap can be seen by observing its May 1, 1982 inventory levels. After a very cold 1982 heating season of approximately 5370 degree days and the unexpected April blizzard, the Company had inventories of 918,788 gallons of propane and 250,564 MCF of natural gas in underground storage.

VI. DECISION AND ORDER

The Council hereby APPROVES the Second Long-Range Forecast of the Berkshire Gas Company and ORDERS that it meet the following Condition in its next Supplement:

1) In its next Supplement, the Company shall address the anticipated effects of price decontrol of natural gas on its forecast of sendout. This analysis should include both projected sendout data for each class, anticipated marketing strategies to ensure both a reliable and least cost supply to gas, anticipated problems with customer accounts receivable.

Paul T. Gilrain, Esq.
Hearing Officer

Dated at Boston this 8th Day of September, 1982.

This Decision was approved by a unanimous vote of the Energy Facilities Siting Council on September 29th, 1982.

Voting in Favor: Margaret N. St. Clair, Esq., Secretary of Energy Resources; Bernice McIntire, Esq, designee of the Secretary of Environmental Affairs; Noel Simpson, designee of the Secretary of Economic Affairs; Richard Pierce, designee of the Secretary of Consumer Affairs; Dennis J. Brennan, Esq., Public Member, Gas; Richard A. Croteau, Public Member, Labor; Thomas J. Crowley, Public Member, Engineering; George S. Wislocki, Public Member, Environment.

Ineligible to vote: Charles Corkin II, Esq., Public Mermber, Oil; Harit Majmudar, Public Member, Electricity.

/s/

Margaret N. St. Clair, Esq.
Chairperson

dated this 1st day of October, 1982.

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition of Eastern Utilities Associates for the Approval of its Second Long-Range Forecast of Electric Needs and Requirements	EFSC No. 81-33

FINAL DECISION

Paul T. Gilrain, Esq.
Hearings Officer

On the Decision:

John P. Hughes, Chief Economist
Margaret A. Keane, Senior Economist

TABLE OF CONTENTS

I. INTRODUCTION

The Council hereby APPROVES the Second Long-Range Forecast of the Eastern Utiliteis Associates subject to certain conditions which the Council orders be met in or before their next filing. These Conditions are specified in part V, *infra.*

II. BACKGROUND AND HISTORY OF THE PROCEEDINGS

Eastern Utilities Associates (EUA) 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".

A. The Retail Subsidiaries

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 1980 population of 639,000.

Eastern Edison conducts electric utility business in two geographically separate areas in southeastern 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 292,000. The Fall River division of Eastern Edison consists of five communities located in and around the city of Fall River, serving a population of approximatley 146,000.

Blackstone conducts electric utility business 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 EFSC jurisdiciton, however the Companies submit it's forecast voluntarily since it is an integral part of the System forecast.

Eastern Utilities Associates ("EUA" or "the Companies") filed their Second Long-Range Forecast of Electric Needs and Requirements on June 15, 1981. Subsequently, a prehearing conference was set for September 30, 1981 and an order of notice published in newspapers of local circulation and posted in each city and town within the Companies' Massachusetts service territory. There were no intervenors or participating persons at the pre-hearing conference.

An initial review of the filing revealed that the, so called, technical supplement, described in detail in part III, <u>infra</u>, was missing. EUA filed the technical supplement on December 23rd, 1981 and staff review was commenced. After numerous staff technical sessions and three rounds of discovery, a bench review was conducted. No party to the proceeding, neither the companies nor the staff requested a hearing before the hearings officer and none was held.

III. DEMAND-SIDE REVIEW

A. Introduction

The load forecast presented to the Council in the EUA Companies' "Second Long-Range Forecast of Electric Power Needs and Requirements" is the product of a new forecasting methodology. As discussed *infra*, the Council had expressed concerns about certain aspects of the Companies earlier methodology in its previous Decision and Order.[1] Rather than address this concern only, the Companies elected to revamp and enhance its entire methodology - the culmination of several years serious effort and expense which involved the adaptation of the NEPOOL/Battelle Model to the Companies' three service areas. The Council's review will cover all the major components of the methodology: the economic/demographic forecasts, the price forecasts, residential sales forecast, commercial sales forecast, industrial sales forecast, and the peak demand forecast. The Council's review was assisted by the helpful EUA staff and by the Companies' technical supplement to the filing, a well prepared document which thoroughly explains the assumptions, equation specifications, data sources, and statistics on the methodology. The scope of this level of documentation has heretofore been typically provided by only the larger, more resource-rich utilities.

Tables 1A and 1B summarize the Companies' forecasts by service area and by customer classes. The overall average growth in system load is forecasted to be .73% per annum through 1990. The overall average growth in energy demand is forecasted to be 1.08% per annum through 1990.

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1 *See* 5 DOMSC 10-38 (Nov. 24, 1980).

Table 1A

Eastern Utilities Associates

EUA System Load Forecast

Peak Demand (MW)	Average Compound Growth Rate for 1980-1990	1980	1985	1990
Blackstone Valley	0.93%	238.0	248.9	261.4
Eastern Edison	1.20%	378.1	397.0	426.3
Total Affiliated	1.10%	616.1	645.9	687.7
Wholesale Customers[2]	(2.62%)	60.2	48.5	46.0
Losses (Montaup Only)	-	18.2	12.5	13.1
Total	0.73%	694.5	706.9	746.8

1. Actual
2. Includes Middleborough Gas & Electric, Newport Electric and Pascoag Fire District.

(Source: Forecast p. II-3)

Table 1B

Eastern Utilities Associates

EUA Energy Forecast by Sector

	System Energy - GWH			
	Ave. Compound Growth Rate for 1980-1990	1980	1985	1990
Residential	1.40%	1,145	1,146	1,316
Commercial	2.44	1,055	1,237	1,342
Industrial	0.08	844	840	851
Streetlighting and Miscellaneous	1.31	43	47	49
Total Affiliated Sales	1.43%	3,087	3,270	3,558
Affiliated Losses & Internal Use	-	166	195	213
Total Affiliated Requirements*	1.49%	3,253	3,465	3,771
Sales for Resale	(2.51%)	419	338	325
Montaup Losses	-	75	71	77
Total System	1.08%	3,747	3,874	4,173

* Blackstone and Eastern Edison

B. Economic/Demographic Forecast

The EUA Companies retained the services of the Planning Economics Group, Boston, Incorporated, (P/E) to provide service area-specific forecasts of key economic/demographic variables. Forecasts of these variables are valuable only in that they are important exogenous inputs to the other forecasting submodels: residential sales, commercial sales, and industrial sales. P/E estimated the following variables for each of three EUA service areas: per capita income, population, employment in the commercial sector, and employment in the industrial sector. P/E also provided historical and forecast data for No.2 oil, retail natural gas, residual oil, the implicit price deflator for personal consumption expenditures, and the consumer price index. The basic approach used by P/E in developing these forecasts was to relate forecasts of county level data series, which P/E maintains in its regional economic database, to data series maintained by EUA for each of its service areas. With one exception, multiple regression techniques were developed to link the EUA data to P/E national and regional data, producing EUA-specific projections of the economic/demographic variable for employment, total personal income, and total population. The regional forecasting model, which projected these three variables, was developed by the National Planning Association (NPA).[2] The model estimates employment and earnings by sector, personal income by source, and total population for 183 Bureau of Economic Analysis (BEA) areas

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2 P/E accesses NPA's models by time-sharing

and 3098 counties using a recursive econometric model. The model contains 30 regression equations which are estimated using ordinary least squares ("OLS"), for each county and BEA area. BEA area data are adjusted to equal national level control values, which are forecast using NPA's national forecasting model, to ensure consisteing. County level data are also constrained to sum to the control values for the BEA area to which they belong. Forecasts for the BEA areas are produced in the first stage of the recursive process. The second stage produces forecasts for county level variables.

P/E used a macroeconomic input-output model (I/O model) to project industrial output. The model generates forecasts of 2-digit SIC industrial activity at the national level, which in turn were used as explanatory variables in some of the equations P/E developed specifically for EUA. The I/O model used by P/E is the interindustry forecasting model, INFORUM, developed at the University of Maryland. INFORUM is based upon the 1972 interindustry transactions survey and has extensive industrial detail (e.g., 4-digit SIC data). Since the technical I/O coeffecients have been modeled as functions of input prices, the model permits factor substitution (e.g., oil-gas substitution). The I/O model is recognized as a flexible and useful forecasting tool for its availablity to forecast national levels of output and their relative disposition by industry.

The Companies are to be especially commended for adding the P/E forecasts of key economic demographic variables to their methodology. Because these variables serve as important input parameters in other submodels, the value of credible projections of these variables cannot be overstated. These efforts satisfy the Council's directive in Demand Condition 5 from the last Decision and Order.

C. Price Forecast

In Demand Condition 4 of the last Decision, the Companies were directed to support certain judgements and assumptions regarding appliance penetrations with a detailed fuel price analysis, disaggregated by sales class. The Companies' response to that Condition has fully satisfied the Council. The 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.

The electric price forecast is a major input to the load forecasts of the separate sales classes, and is itself dependent on the energy (kWh) and the demand (kW) generated from the load forecasts. Because of this dependency the price forecast was developed in an interactive manner using the outputs of the load forecast as inputs to the price forecast. Other inputs to the price forecast were system demand costs, system generation characteristics, fuel prices and hour-by-hour load shapes. System generation characteristics included unit capacities, heat rates, maintenance schedules and forced outage rates. Because of the iterative nature of the forecast process, the energy and peak demands were first assumed judgementally in order to develop an initial price forecast. The first-run price forecast was then used to drive the load forecasting model along with its other required inputs to develop peak loads and energy. These peak loads and energy projections differed from the values originally assumed; the price forecast is then redone, i.e., iterated, using the new values. In a similar manner, the newly generated prices are compared with the initial values to assess the sensitivity of the price forecasting mechanism and also to determine whether another iteration is needed. This process is repeated until the change in the electric price forecast is minimal. Table 3 reproduces the Companies' price forecast for the Eastern Edison Division, disaggregated into energy and demand components and by service class.

Table 3

Eastern Utilities Associates

Electric Price Forecast
Eastern Edison Electric Company
(cents/kWh)

D. Residential Forecast and Forecast Methodology

1. Introduction

The EUA Companies' Residential forecasting Models is derived from the residential power submodel in the NEPOOL/Battelle Load Forecast Model.[3] The use of this methodological framework culminates several years of effort by the Companies to upgrade their forecasting capability, due, in part, to the incessant urging of the Council in its previous Decisions and Orders. The resulting forecast is for a 1.4% average annual increase in residential energy demand through 1990.

The Companies' previous effort to forecast residential sales was criticized (but not rejected) in the last Decision of the Council (See 5 DOMSC 10-38, (Nov. 24, 1980)). Three conditions in that Decision[4] applied directly to the residential forecast methodology and are each discussed separately, infra. In general, the Council's concerns focused on the Companies' use of time-trend analysis which had been inadequately supported by largely aggregated 1970 census data. No age-cohort demographic data were developed, nor were household formation estimates used. As discussed directly below, the Companies have made a substantial and laudable commitment to improve their methodology.

2. Review of the Residential Forecasting Methodology

The Companies project residential energy sales by employing an end-use modeling approach. Projected annual class sales are estimated by aggregating the annual energy requirements of each specific end-use.

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3 See: 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 I. Structural of the Power Module - Chap. 1, Residential Power Submodule "Load Forecasting Task Force of the NEPOOL Planning Committee, Preliminary, October, 1981.

4 Demand conditions 1, 3, and 4, which are reproduced in Appendix A.

These are calculated by multiplying the total number of consuming units for the given end-use by the average annual consumption per unit. Internal to the model are 19 specific appliance types. The major steps necessary to project the total residential energy demand of these appliances begin as follows:

(1) the number of households must be calculated from demographic data;

(2) the saturation levels of the 19 appliance types must be estimated, partially by applying income-appliance saturation functions, which are then applied to the number of households to compute the total number of appliances; and

(3) annual energy use for the 19 appliances must be adjusted to account for price elasticity, appliance efficiencies, changing family size, income changes and appliance substitution (e.g., the use of microwave ovens reduce electric range use).

Figure 1 displays a flowchart of these major steps.

Demographic data from the 1970 and 1980 Censuses and exogenous forecasts of population for each of EUA's service areas form the starting point for calculating the number of households. Population estimates for 1971 through 1979 were interpolated from the 1970 and 1980 Census values. The 1981 through 1990 population projects were supplied by the Companies' consultant, the Planning Economics Group. Because different age groups have different household formation rates, the total population is disaggregated into distinct age-cohort groups. The 1970 age breakdown was obtained from Census data but 1980 Census figures were not available to the Companies. "Second-best" state trends were used from the NEPOOL model database.

Figure 1

Eastern Utilities Associates

Estimation of the Number of Appliances in the Residential Sector

Population Estimate

Household Formation Ratio

No. of Households

Distribution of Dwelling Type

Distribution of Income

Income/Appliance Saturation by Dwelling Type

No. of Households by Income Class and Dwelling Type

Number of Appliances in Ea. Income Class and Dwelling Type

Total No. of Appliance by Type

Source: p. II-22, 2nd Forecast

The age-cohort group estimates are converted to household counts by multiplying first the population in each age group by the respective household formation rate and second, by the projected national trend on the formation rate values, i.e.,

$$HH_{a,t,i} = POP_{a,t,i} \times HFR_{a,t,i} \times HFT_{a,t,i}$$

where

$HH_{a,t,i}$ = Number of households in year t and service area (EUA division) i headed by a person in age group a;

$POP_{a,t,i}$ = Number of persons in age group a, year t, and service area i;

$HFR_{a,t,i}$ = Household formation rate for persons in age group a, year t, and service area i; and

$HFT_{a,t,i}$ = Household formation trend for age group a, year t, and service area i.

Summing over all age groups yields the total number of households for a specific year and distribution area. After the total number of households is determined, they are disaggregated by owner and renter categories, and by single and multi-family dwelling categories. Again, because of the delay in processing and publishing the results of the 1980 Census. 1970 Census data was used. The resulting distribution of housing units by dwelling type and ownership is shown in Table 4. The results in this table are illustrative of the importance of service area specific demographic data, as opposed to the use of state-wide averages and trends. For example, future expectations with respect to the penetration of more efficient appliances and/or weatherization efforts are highly sensitive to dwelling ownership. Over 80% of the dwelling units in Blackstone Valley are owner occupied, compared to less

Table 4

Eastern Utilities Associates

Distribution of Housing Units by Dwelling Type and Ownership

	Single Family	Multi-Family	Total
Blackstone Valley:			
Owner Occupied	34.4%	47.9%	82.3%
Renter Occupied	3.1%	14.6%	17.7%
Total	37.5%	62.5%	100.0%
Brockton Division:			
Owner Occupied	64.2%	7.8%	72.0%
Renter Occupied	3.9%	24.1%	28.0%
Total	68.1%	31.9%	100.0%
Fall River Division:			
Owner Occupied	33.4%	13.2%	46.6%
Renter Occupied	3.7%	49.7%	53.4%
Total	37.1%	62.9%	100.0%

Source: p. II-19, Second Forecast

than 50% in the Fall River division. EUA is commended for making this long overdue enhancement to its residential methodology. When 1980 Census and Company survey data become available, the calculation of household formation rates and trends should be promptly updated.

Estimates of personal income, distributed across households, are used to compute the saturation levels of appliances, a most critical procedure in end-use modeling. Total personal income in each service area is computed from historical and exogenously projected per capita income data and from population values. Per capita income is in real 1970 dollars and is deflated using the Consumer Price Index. Once a service area's total personal income has been computed, the income is distributed among 20 income classes and the four housing types.

The number of households by income classes and dwelling type is then applied to income/appliance saturation estimates by dwelling type to derive the number of appliances in each income class and dwelling type. Using regression techniques, appliance saturations as a function of personal income were estimated for clothes washers, clothes dryers, dishwashers, freezers, room air conditions, central air conditions, and electric ranges.[5] Each saturation is then applied to the number of households by dwelling type and by income class. Summing overall income groups and dwelling types generates the total number of appliances in use. Knowing average use per appliance and adjusting for price elasticity, a credible estimate for total energy demanded by the sector,

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5 Water heater and space heating types are calculated from billing records.

in kWh, is achieved.[6] Figure 1 outlines, diagramatically, the major steps for calculating the number of appliances. Figure 2 works through in greater detail the major steps used by the Company to project aggregate energy use of a single appliance, the electric clothes dryer. Cross-referencing Figure 2 with Table 4, it is clear that the saturation of clothes dryers is greater in areas where single-family, owner occupied dwellings predominate relative to multi-family, renter-occupied housing, supporting the common assumption that the penetration of many major appliances is highly correlated to income.

The conceptual framework of the companies' new end-use residential forecast methodology is an important enhancement to the overall forecast filing. The Council finds that the use of an end-use approach is more appropriate for EUA's relatively small service areas than would a long-run econometric approach.[7] However, the Council is mindful of the fact that even the best and most appropriate methodology is worthless if

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6 Theoretically, adjustments should also be made for technical change (e.g., new appliances), structural change (e.g., new tax laws), cross-elasticity (e.g., a change in the price of a competitive energy form such as natural gas), and miscellaneous behavioral changes (e.g., conservation ethic). None of these adjustments can be easily derived empirically and must, at best, be adjusted judgementally based in large part on the expected "evolution" of federal and state regulatory policies. Besides adjustments for short and long-run price elasticity, the Company made additional adjustments for expected trends in appliance efficiencies, family size, and household income. These adjustments have satisfactorally addressed the Council's concerns in Demand condition 4 in the Council's last Decision (See 5 DOMSC 10-31, at 37, (Nov. 24, 1980)).

7 Econometric forecasting models, which rely on multiple regression techniques, are driven by past economic phenomena. In attempts to model small service areas, forecasts can be severely distorted by one-time events such as the short-term shutdown of a large factory, the construction of a major housing project, shopping mall or industrial park, or even a major fire. In larger service areas the impacts of such events are neutralized by the shear size and economic diversity of the region.

Figure 2

Eastern Utilities Associates

Estimating the Number of Clothes Dryers
and Aggregate Projected Energy Usage

A. Appliance Saturation Functions: Clothes Dryers

(1) Owner Occupied Housing Units
   a. Blackstone - 99.4 + 15.4 X LN(I) (R^2=0.80)
   b. Brockton - 136.7 + 20.5 X LN(I) (R^2=0.83)
   c. Fall River - 122.0 + 18.2 X LN(I) (R^2=0.85)

(2) Renter Occupied Housing Units
   a. Blackstone - 62.9 + 8.85 X LN(I) (R^2=0.49)
   b. Brockton - 71.5 + 9.87 X LN(I) (R^2=0.70)
   c. Fall River - 25.9 + 4.10 X LN(I) (R^2=0.58)

B. Appliance Saturation Summary: Clothes Dryers

		1980	1985	1990
(1)	Blackstone	28.58%	29.38%	30.82%
(2)	Brockton	41.03	41.63	43.19
(3)	Fall River	21.74	22.14	23.16

C. Appliance Elasticity Coefficients: Clothes Dryers

(1) Short-term: -0.5
(2) Long-Term: -1.0

D. Appliance Efficiency Savings: Clothes Dryer

(1)	1980 Energy Reduction	16%
(2)	Total Standard Reduction	25%
(3)	Year of Fall Implementation*	2000

E. Appliance Average Use Summary (kWh)

		1980	1985	1990
(1)	Blackstone	859	657	682
(2)	Brockton	880	681	722
(3)	Fall River	815	657	700

F. Residential Energy Forecast (MWH)**: Clothes Dryer Only

		1980	1985	1990
(1)	Blackstone	18,420	15,060	17,010
(2)	Brockton	35,410	31,570	38,460
(3)	Fall River	9,630	8,500	10,070

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* Based on assumed life of appliance

** Adjustments to average usage include price elasticity adjustments, appliance efficiency trends, and adjustments due to family size and household income.

inadequately supported with the requisite, service area specific data. In this regard, the Council is particularly pleased with the Companies' commitment to diminish its reliance on NEPOOL residential data (e.g., state-wide estimates) by commencing an appliance saturation survey.[8] (Response to Question 1, Second Set of Staff Information Requests, April 23, 1982).

The EUA Companies thus join the ranks of the other major electric systems operating in Massachusetts that have sponsored a service area survey.[9] These surveys, which should be periodically reported, are important for establishing both base use and trends in ownership and usage of household appliances. End-use modeling efforts are especially data intensive and service area forecasts from end-use models must be based on an accurate service area database. In the Council's last Decision and Order, the Companies were directed to advise the Council on its progress in implementing a service area appliance saturation survey.[10] The Council finds that the condition has been fully complied with.[11]

In summary, the Council finds that the EUA Companies' Residential Energy Forecast methodology has advanced significantly in both sophistication and credibility. The Council anxiously awaits the integration of the new survey data, supplemented with 1980 census data, with the new

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8 Response to Question 1, Second Set of Staff Information Requests, April 23, 1982.

9 The other systems are: Northeast Utilities (Western Massachusetts Electric), NEES (Massachusetts Electric), Boston Edison, MMWEC, and COM/Electric.

10 Demand Condition 3, 5 DOMSC 10, at 37.

11 Most of the concerns expressed in Demand condition 1 in the last Decision (relating to trend analysis) have been made moot by the change in methodology; the remaining concerns have been satisfied and adequately documented.

methodology.

E. Commercial Forecast and Forecasting Methodology

As with the Residential forecasting methodology, the Companies used the commercial power submodel from the NEPOOL/Battelle Model to project electric energy requirements of the commercial class. This resulted in a projected annual increase in commercial demand of 2.44% through 1990. Previously, the Companies had used multiple regression analysis where the projected number of commercial customers and their average usage were separately estimated. The two values were multiplied together to calculate projected annual commercial sales. The number of commercial customers was assumed to be a function of population and household size. Average usage was assumed to be a function of population and the ratio of residential to commercial customers. Usage was subsequently adjusted for conservation, judgementally.

In the new methodology, energy consumption in the commercial sector is assumed to be a function of the level of economic activity in EUA's three service areas. In the model itself, economic activity is measured directly by projected commercial employment in the service areas and by an estimate of energy intensiveness (kWh per employee). The product of these values is then adjusted by price elasticity and non-price related conservation assumptions. This procedure is summarized as follows:

EC= EMP X CPE X PEAF X CONS

where

EC = annual commercial energy consumption

CPE = energy consumption per employee

EMP = commercial employment

PEAF = price elasticity adjustments factor, and

CONS = non-price related conservation factor.

Commercial employment projections were done by EUA's consultant, the Planning Economics Group. Employment was estimated separately for each service area using multiple regression techniques. Employment was assumed to be a function county-level employment in selected commercial sector industries. Employment in the sector is then linked to the national economy using real GNP.

Energy intensiveness (CPE) was also estimated using regression techniques, using historical employment and energy sales, adjusted with "commercial elasticity aging factors "from the NEPOOL/Battelle Model. These aging factors effectively lag price changes over some period of time, the assumption being that commercial entities cannot react instantaneously to price changes.

The price elasticity adjustments factors (PEAF) were calculated from projected price levels (from the Price Forecast), short and long-run elasticity estimates, and a time-trend variable. The Non-price related conservation factors (CONS) were judgementally estimated by assuming 20% conservation by 1990; a conservation conversion factor was applied to the energy intensiveness variable to reflect this. Thus, the variable CONS has a value of 0.99 in 1981; 0.93 in 1985; and 0.80 in 1990.

Overall, the Council commends this new methodology because (1) it improves upon the earlier effort by using more service areas specific data; (2) the variables are internally consistent among themselves and with other parts of the EUA forecast; and (3) the model is theoretically plausible and appropriate to the Companies service areas and resources.

The Companies are urged to expand the commercial customer database with more end-use specific information (perhaps for selected major commercial loads) and to compare their forecasts and forecasting assumptions with neighboring service areas (e.g., COMM/Electric, Narragansett Electric, and Boston Edison).

F. Industrial Forecast and Forecasting Methodology

As in the residential and commercial sectors, EUA utilized the NEPOOL/Batelle model's industrial power submodel in its forecast of industrial class electric energy requirements. Growth in industrial demand was forecast at .08% per annum. In past forecasts, the Company had used a simplistic method based on composite growth rates derived from historical data and customer interviews. That method was found unsatisfactory in EFSC 79-33, where the Council stated, "The current industrial forecast relies to a greater degree on unexplained judgement than any other part of the Companies' forecast impinging on the reliability and appropriateness of the method". The Decision further stated that, "the Council must find that EUA has failed to present an adequate theoretical basis for its industrial forecast."

In the current filing, EUA calculates estimated annual energy consumption per employee, disaggregated by two digit SIC[12], and multiplies those figures by estimated number of employees by SIC. The Companies describe the equation as follows:

$$EI_{t,i,j} = EMP_{t,i,j} * AC_{t,i,j}$$

Where

$EI_{t,i,j}$ = Annual energy consumption in industrial SIC_j, year t and service area i,

$EMP_{t,i,j}$ = Employment in industrial SIC_j, year and service area i, and

$AC_{t,i,j}$ = Annual energy consumption per employee in SIC_j, year t and service area i.

12 As only five years of SIC specific data was available for the Fall River service territory, Fall River's industrial class was not disaggregated.

The kWh/employee variable is adjusted for price elasticity by the same method used in the commercial sector, described supra at 22. Electric prices were converted into real terms using the implicit Price Deflator for manufacturing supplied by the US Department of Commerce, Bureau of Economic Analysis. EUA estimated Price Deflater values for 1980-1990 by observing the Price Deflater rate of change versus the Consumer Price Index rate of change and applying the difference to historical figures.

Energy intensiveness was also forecast in the same way as in the commercial submodel, using the NEPOOL/Batelle "industrial elasticity aging factors".

A further adjustment was made in Blackstone's SIC 30 to account for a large hydroelectric generator.

The industrial sector is typically difficult to model due to its high volunerability to economic fluctation. Macroeconomic factors were taken into account in the employment forecasts generated for EUA by its consultant, Planning Economics.

Planning Economics utilized 19 equations, using region specific and national output measures, to forecast employment by industry and service territory. County specific data was used as a proxy for the individual service territories to identify and forecast regional economic activity.

The Council applauds the tremendous amount of progress that the Company has made in the past year. The use of SIC specific data and the sophistication of the methodology used to generate the employment regression equations are welcome additions. The Company is commended and encouraged to continue its model development.

G. Peak Load Forecast

The Companies' methodology for projecting peak load demands is the same approach most typically used in the industry: the individual annual net energy projections are divided by the product of the expected annual load factor[13] and the number of hours in the year. This results in an average annual load increase of .73%. Two important adjustments are made during the calculations. First, an adjustment is made for small power producers, particularly, low head hydro, and second, as a form of load management, the Companies assume that all currently uncontrolled electric water heaters will be controlled by 1987. Beginning in 1982, current and projected numbers of controlled electric water heaters will have their time clocks reset twice annually so as to further reduce seasonal peaks.[14] The Companies believe that because their peak exposure exists over a relatively long period of time (at least 5 hours), load management options are constrained to appliances with storage capability. These are presently limited to electric water heaters. The Companies are urged to continue researching and evaluating innovative approaches to controlling future peak demands. As discussed in the supply-side review, infra., the Companies future planning needs may require such efforts.

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13 The "load factor" is the ratio of the average load during a specified period to the maximum load occurring during the period.

14 In aggregate, the peak load reduction due to water heater controls is expected to increase from 0.7 MW in the summer of 1981 to 29.3 MW during the summer of 1990.

H. Conclusions: Demand - Side Review

Overall, the EUA Companies are highly commended for committing the resources for the development of its current forecasting methodology. The various components are conceptually sound, appropriate to the Companies' current forecasting needs, and sufficiently flexible to give the Companies a valuable planning tool for many years to come. As per our recent decision and order to the Boston Edison Company[15] we urge the EUA Companies to now focus on improving the quality of data that support the methodology. In this regard the Companies on-going commitment to collect service-area end-use data is especially noted and further, encouraged. The Council is also mindful of the now chronic delays in the dissemination of the 1980 U.S. Census data, particularly disaggregated household information by towns. The Council hopes that this data will be forthcoming and rapidly applied to the Companies' methodology.

The forecasted average annual growth figures - 1.4% for residential, 2.44% for commercial, .08% for industrial, and .73% for peak load - are based on reasonable statistical assumptions and accurate historical data.

The EUA Companies' forecasts and forecasting methodology are hereby APPROVED.

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15. 7 DOMSC 93

IV. Supply Analysis

A. Introduction

All of the electric generating capacity in the EUA system is owned or contracted for by the Montaup Electric Company, a wholly-owned subsidiary of the Eastern Edison Company. The Companies, through Montaup presently own or have contracted for 848 MW of generating capacity and project to own or have contracted for 937 MW of capacity at the terminus of the forecast period.[16] The Companies forecast that they will have sufficient capacity available to them to meet peak demand throughout the forecast period and meet NEPOOL reserve requirements.[17] However the Companies make certain assumptions about on-line dates of nuclear units presently under construction, existing oil-fired units which may or may not be converted to coal and the proposed sale of 23 MW of its share of the Millstone 3 nuclear unit which will affect this forecast. The Company forecasts a tentative reduction in existing peak load due to a proposed electric water heater load control system in response to supply Condition No. 1 of the Council's Decision and Order on the Companies last filing.[18] Lastly the Companies respond to the Council's second supply Condition in that Order[19] by stating their support for the promotion of renewable resources and co-generation, and forecast certain energy or capacity additions from these sources through 1990. Each of these issues will be discussed in turn.

16 See Table A
17 Forecast Table E-17
18 5 DOMSC 10, 38; EFSC 79-33, Nov. 24, 1980.
19 id.

B. <u>Forecasted Nuclear Additions</u>

1. Seabrook 1 and 2

The Companies state that the in-service dates for the Seabrook Units, of which the Companies own 2.9% or 67 MW total in both units, reflect the Companies judgements and not that of the projects lead participant, Public Service Company of New Hampshire ("PSNH"). The Companies estimate Seabrook Unit No. 1 will be in-service during the winter of 1984-1985, six to twelve months later than the PSNH estimate. They project that Unit No. 2 will come on-line during the winter of 1987-88, twelve to eighteen months later than the most pessimistic PSNH forecast.[20] The issue of the on-line dates of these units has troubled the Council in the past and we have required other companies to prepare contingency plans if a variation of the on-line dates would affect their ability to meet their capability responsibility.[21]

On July 16th, 1982, the Public Utilities Commission of New Hampshire effectively deferred the the construction of Seabrook No. 2 indefinitely .[22] While PSNH has appealed this ruling, there is, at this time, doubt that Unit No. 2 will be on-line during the forecast period and therefore, we will consider the Companies forecast without the addition of 34 MW of capacity in the power year

20 See PSNH forecast of Electric Needs and Requirements filed with the Council for informational purposes.

21 See: <u>In Re Fitchburg Electric Co.</u> 7 DOMSC ____, EFSC No. 81-11 (1982); <u>In Re NEES</u> 7 DOMSC ____, EFSC No. 81-17 (1982).

22 The New Hampshire P.U.C. ordered PSNH to suspend investment in Unit No. 2 until such time as PSNH could make such investments without jeopardizing its financial viability. See: NHPUC Docket No: DF 82-141, pp. 26-38 (1982). Second Supplemental Order No. 15, 760, p. 2 (1982).

1987-88.[23] (See Tables 1-A and B). This results in a 1 MW shortfall in the system's reserve margin, as established by NEPOOL. Though this may appear to be a relatively insignificant matter, the Companies will be required in their next forecast to insure that all NEPOOL reliability standards are fully met, taking into account potential delays in new units coming on line.

The NHPUC's order is likely to increase the investment of PSNH in Unit No. 1 and, thus enhance the possibility that construction on that unit will be completed as forecast by EUA, if not sooner. We will thus accept the Companies' tentative in-service date for Seabrook I of power year 1984-85.[24]

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23 We note that MMWEC, the second largest owner of the Seabrook Unit and NEES, the fourth largest, projected that Unit No. 2 would be in-service during power year 1987-88 and 1988-89 respectively. DF 82-141 p. 26-27; In Re New England Electric Co. 7 DOMSC ___, EFSC No. 81-17 (1982). These projections were made prior to the N.H. P.U.C.'s recent decision which will defer construction on the unit to a later date.

The Council's concern was again shown to be justified by the report of the N.H.P.U.C. staff to the Commission in Docket 81-312 Investigation into Supply and Demand, August 16, 1982. The P.U.C. staff reported that projected on-line dates for Seabrook Unit No. 1 by P.S.N.H were unrealistic as were the Company's projections on decommissioning and contruction costs.

24 The Council is concerned however that the owners of Seabrook may have difficulty obtain an operating license for the plant due to the lack of an adequate evacuation plan for the Hampton/Salisbury beach areas. See 10 CFR parts 50.34, 50.54, 50.57(a)(3) and Appendix "D". The Council is also concerned in light of the fact that much of the recent construction delay has been due to labor disputes. DF 81-141, p. 32. The contract for the iron workers at the plant expires this year, while those for carpenters and pipefitters expire in 1983. All three unions struck the plant during the 1979-81 time frame. Transcript DF 82-63 (N.H.P.U.C.) Vol. 5, pp. 72-78; DF 81-141, p. 32. The P.S.N.H. construction schedule makes no allowance for strikes. id. pp. 31-33.

This fact further supports the unlikelihood that Unit 2 will be in-service during the forecast period. If Unit 1 were to come on line as scheduled (a projection the N.H.P.U.C. is skeptical of. DF 82-141, p. 33) the resultant two year deferral of Unit No. 2 would make it possible to have that unit in-service by power year 1990-91. Given the history of this project, we feel caution is the preferred course.

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Table A

(Part 1)

Eastern Utilities Associates

System Load and Capability by Power Year
(Megawatts)

	Fuel Type (1)	1980/81	1981/82	1982/83	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/90
.PABILITY											
;omerset Steam......	F	198	198	198	193(3)	193	193	193	193	193	192
;omerset Jets	F	48	48	48	48	48	48	48	48	48	48
:anal No. 2	F	292	292	292	292	292	292	292	292	292	292
Subtotal..........		538	538	538	533	533	533	533	533	533	533
)INT OWNERSHIP											
1ass. Yankee........	N	7	7	7	7	7	7	7	7	7	7
:onn. Yankee........	N	26	26	26	26	26	26	26	26	26	26
1aine Yankee........	N	29	29	29	29	29	29	29	29	29	29
/ermont Yankee......	N	12	12	12	12	12	12	12	12	12	12
)yman No. 4.........	F	12	12	12	12	12	12	12	12	12	12
;eabrook No. 1 and 2	N	--	--	--	--	33	33	33	67	67	67
1illstone No. 3.....	N	--	--	--	--	--	46	46	46	46	46
?ilgrim No. 2.......	N	--	--	--	--	--	--	--	--	--	
Subtotal..........		86	86	86	86	119	165	165	199	199	199
JRCHASES											
:anal No. 1.........	F	142	142	142	142	142	142	142	142	142	142
?ilgrim No. 1.......	N	74	74	74	74	74	74	74	74	74	74
:leary No. 9........	F	80	75	70	64	56	--	--	--	--	--
:olson Cove.........	F	7	7	7	7	7	--	--	--	--	--
Subtotal..........		303	298	293	287	279	216	216	216	216	216

Table A

(Part 2)

Eastern Utilities Associates

System Load and Capability by Power Year
(Megawatts)

	Fuel Type (1)	1980/81	1981/82	1982/83	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/
SALES											
Newport............		15	10	10	10	10	10	10	10	10	1
Pascoag............		2	3	3	3	3	3	1	1	1	[illegible]
Middleboro.........		7	4	4	4	4	4	--	--	--	-
Braintree..........		35	30	30	30	30	--	--	--	--	-
Taunton............		20	20	10	10	--	--	--	--	--	-
Subtotal.........		79	67	57	57	47	17	11	11	11	1
Total EUA System Capability............		848	855	860	849	884	897	903	937	937	93
EUA Capability Responsibility in NEPOOL...		824	788	798	807	841	859	859	875	887	90
Excess (Deficit) in NEPOOL(2)..........		24	67	62	42	43	38	44	62	50	3
EUA System Load.....		693	668	676	684	707	710	710	723	733	74
EUA System Reserve %		22	28	27	24.1	25	26.3	27.2	30	29	2
Nuclear Resources % of Load............		20	21	20	20	24	32	32	36	36	3
EUA Estimated NEPOOL Reserve Requirement-%		19	18	18	18	19	21	21	21	21	2

NOTES:
(1) F=Fossil; N=Nuclear
(2) Shortages to be made up by short-term purchases
(3) De-rating due to conversion to coal.

Table A-1
(Part 1)

EXISTING FORECAST REVISED WITHOUT SEABROOK 2

Eastern Utilities Associates

System Load and Capability by Power Year
(Megawatts)

	Fuel Type (1)	1980/81	1981/82	1982/83	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989
CAPABILITY											
Somerset Steam......	F	198	198	198	193(3)	193	193	193	193	193	19
Somerset Jets	F	48	48	48	48	48	48	48	48	48	4
Canal No. 2	F	292	292	292	292	292	292	292	292	292	29
Subtotal..........		538	538	538	533	533	533	533	533	533	53
JOINT OWNERSHIP											
Mass. Yankee........	N	7	7	7	7	7	7	7	7	7	
Conn. Yankee........	N	26	26	26	26	26	26	26	26	26	2
Maine Yankee........	N	29	29	29	29	29	29	29	29	29	2
Vermont Yankee......	N	12	12	12	12	12	12	12	12	12	1
Wyman No. 4.........	F	12	12	12	12	12	12	12	12	12	1
Seabrook No. 1......	N	--	--	--	--	33	33	33	33	33	3
Millstone No. 3.....	N	--	--	--	--	--	46	46	46	46	4
Pilgrim No. 2.......	N	--	--	--	--	--	--	--	--	--	
Subtotal..........		86	86	86	86	119	165	165	165	165	16
PURCHASES											
Canal No. 1.........	F	142	142	142	142	142	142	142	142	142	14
Pilgrim No. 1.......	N	74	74	74	74	74	74	74	74	74	7
Cleary No. 9........	F	80	75	70	64	56	--	--	--	--	-
Colson Cove.........	F	7	7	7	7	7	--	--	--	--	-
Subtotal..........		303	298	293	287	279	216	216	216	216	21

Table A-1
(Part 2)

EXISTING FORECAST REVISED WITHOUT SEABROOK 2

Eastern Utilities Associates

System Load and Capability by Power Year
(Megawatts)

	Fuel Type (1)	1980/81	1981/82	1982/83	1983/84	1984/85	1985/86	1986/87	1987/88	1988/89	1989/
SALES											
Newport...........		15	10	10	10	10	10	10	10	10	10
Pascoag...........		2	3	3	3	3	3	1	1	1	1
Middleboro........		7	4	4	4	4	4	--	--	--	--
Braintree.........		35	30	30	30	30	--	--	--	--	--
Taunton...........		20	20	10	10	--	--	--	--	--	--
Subtotal.........		79	67	57	57	47	17	11	11	11	11
Total EUA System Capability...........		848	855	860	849	884	897	903	903	903	903
EUA Capability Responsibility in NEPOOL...		824	788	798	807	841	859	859	875	887	904
Excess (Deficit) in NEPOOL(2)..........		24	67	62	42	43	38	44	28	16	(1
EUA System Load.....		693	668	676	684	707	710	710	723	733	747
EUA System Reserve %		22	28	27	24.1	25	26.3	27.2	24.9	23.2	20
Nuclear Resources % of Load...........		20	21	20	20	24	32	32	31	31	30
EUA Estimated NEPOOL Reserve Requirement-%		19	18	18	18	19	21	21	21	21	21

NOTES:
(1) F=Fossil; N=Nuclear
(2) Shortages to be made up by short-term purchases
(3) De-rating due to conversion to coal.

Table B

EUA System Reserve (summer)

As forecast	1988	1989	1990
MW	180	170	190
%	24.9	23.2	25.4
Without Seabrook 2 and Pilgrim 2			
MW	180	170	156
%	24.9	23.2	20.9
Projected NEPOOL Reserve			
%	21	21	21

* Calculated from Forecast table E-17 and EUA Ex-1, Forecast p. 11-46. Also see Table A and A-1 *supra*.

2. Millstone-Unit No. 3

The Council has recently approved the forecast of the Northeast Utilities Companies ("NU") which included an in-service date of power year 1986-87 for Millstone Unit 3. E.U.A. has adopted the N.U. projections in this regard and they are thus acceptable to the Council. Of concern to the Council was the Companies' proposed sale of 2.0% or 23 MW of this unit in light of the discussion of Seabrook Unit 2, supra and the cancellation of the Pilgrim II unit by Boston Edison, in which the Companies had a 2.15% ownership interest (25 MW). The companies have recently amended their forecast and chosen not to sell their share of Millstone 3.

The Companies forecast to own or have contracted for 261 MW of nuclear capacity by 1990. This represents 28.9% of their peak load requirements.[25] Without the addition of Seabrook Unit 2 this falls to 227 MW or 25.1% of their peak load requirements. The Companies' reliance on seven nuclear units (including Seabrook 2) in relatively small blocks of power improves system reliability.

C. Coal Conversions

The Companies have prepared a Draft Environmental Impact Report for the Secretary of Environmental Affairs on the conversion of their Somerset Units 5 and 6 to coal. These units represent 198 MW of capacity presently but would be de-rated to 193 under the proposed conversion.[26] The cost of the proposed conversion is $56,000,000[27] or

25 EUA Ex-1, supra.
26 The conversion will substantially extend the economic life of the plant.
27 E.N.F. No.: 4339; February 11, 1982

approximately $301/Kw. This compares to projected costs of $1956/Kw for the Seabrook Units 1 and 2[28] and $2261/kw[29] for Millstone 3. The conversion, which could be completed by the summer of 1984, would reduce the companies dependence on oil on peak by approximately 27.1% in 1984 and 24.8% in 1990. The Council encourages the Companies to pursue this cost-effective oil-backout conversion within the appropriate environmental guidelines set forth by state, local and federal agencies.[30]

D. Load Management

In response to the Council Decision and Order in EFSC 79-33,[31] the Companies propose to institute a program of load management which will initially focus on electric water heaters. The Companies made the assumption, for forecast purposes, that all electric water heaters would be controlled by 1987. The Company did not specify the means by which this would be achieved. The Companies stated that the feasibility of such conversions, the load management effects and the mechanism required are currently under review by a Company task force. The Council encourages this effort and expects to have the results detailed in the next filing by the Companies.

E. Renewables and Co-Generation

In its last consideration of the Companies forecast, the Council

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28 This analysis predated the N.H.P.U.C. latest order deferring Unit 2 which will substantially raise the long term cost. DF 82-141, p. 38, See: Dissenting opinion of Comm. McQuade; DE 81-312; Technical Paper G.

29 In Re Northeast Utilities, 8 DOMSC __, EFSC NO. 82-17 (1982) p. 72. Recent published reports show the costs even higher.

30 Unfortunately, the conversion to coal of CommElectric's Canal Unit 1, in which EUA has a 142 MW entitlement, does not appear likely. EUA Ex."I".

31 5 DOMSC 10, 38 (1980)

conditioned the decision to the effect that:

> "2. The Council also encourages EUA to pursue actively and support the promotion of renewable energy resources and cogeneration in Massachusetts. The next EUA filing should address this point."
>
> 5 DOMSC, 10, 38 (1980)

The Companies response to this point is:

> "(g)...EUA supports such endeavors and includes them in its forecast, when known"

Additionally, the Companies claim to be actively involved in the promotion of low head hydro electric energy. As evidence of this the Companies contracted with one source for 3,100 MWH/yr. in 1981 and anticipate a total of 23,900 MWH/yr. of hydroelectric energy by 1983 (See Table C). This pursuit of hydroelectric resources is commendable. However, the Companies must not stop here, but should analyze the entire ambit of renewable resources and cogeneration for additional energy. Other utilities in the Commonwealth have undertaken substantial and aggressive programs to back out oil through the use of cogeneration, renewable resources, and conservation programs.[32] The Council understands that EUA is not nearly as large as some of these utilities, nor does it have their resources; however, private companies smaller than EUA have also been aggressive and successful in pursuit of such alternatives.[33]

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32 See: New England Electric's "NEESPLAN", Northeast Utilities' "Programs for the 1980s and 1990s", which have received EFSC and DPU endorsement in part; and the DPU allowance of a $5,000,000 bond.
issue by MMWEC for development of cogeneration and renewable resources by municipal light boards. (See: DPU 20248).

33 We note for example, Nantucket Electric's promotion of wind power and Fitchburg Electric's pursuit of hydro capacity.

TABLE C

EUA HYDROELECTRIC PLAN

Hydro Site Designation	Annual Deliveries to BVE* - Mwh	In-Service Date	NEPOOL ADVERSE Capacity Rating MW
Current Source			
Tupperware	3,100	1981	-0-
Prospective Purchases			
Blackstone Fall.	3,800	1982	-0-
Roosevelt Hydro	3,800	1982	-0-
Woonsocket Hydro	7,000	1982	-0-
Prospective Company-Owned Facility			
Blackstone Station No. 2	6,200	1983	-0-

(* Blackstone Valley Electric Company)

The Companies service territory contains a substantial industrial base and numerous additional potential hydroelectric sites which have been identified by government agencies.[34] In addition, the cost of certain of the conservation initiatives which have been undertaken by Mass. Electric Co., Western Mass. Electric Co., Commonwealth Electric and other companies have been allowed as a valid cost of service by the DPU (see DPU No. 800 and 957).

The Council is fully cognizant of the fact that the cancellation of Pilgrim Unit No. 2 and the indefinite deferral of Seabrook Unit No. 2 did not become realities until well after the Companies 1981 filing with the Council. However, as stated in EFSC 79-33, "The Commonwealth and the Nation's energy problems are complex and cannot be assumed to be resolved simply by purchasing available nuclear capacity from New Hampshire."[35]

In light of the circumstances transpired from the March 31, 1981 filing, it has become imperative that the Companies pursue alternatives such as renewables, cogeneration and load management. The Council fully expects, and so conditions this Decision, that the Companies will develop a unified long-range supply plan which shall set forth the Companies plans for filling the potential Seabrook 2 gap, discuss oil backout strategies, and vigorously explore all conservation and alternative supply options available to the Companies. Consideration of cogeneration and renewable resource potential shall not be limited to that which is available within the bounds of the Companies' service territory. The

34 See: Hydropower Sites of the United States. Developed and Undeveloped, F.E.R.C., (1981); Potential for Hydropower Development at Existing Dams in New England, N.E.R.B.C. (1980).

35 5 DOMSC 10,34.

Council expects the Company to further expand its commendable pursuit of low head hydro electric energy and to avail itself of the advice and expertise at the Massachusetts Executive Office of Energy Resources, and to cooperate fully with that agency.

F. Conclusions: Supply Plan

If the three nuclear units under construction come on line as forecast, EUA will have more than sufficient capacity to meet all of its responsibilities under NEPOOL and satisfy the Council's mandate to ensure a reliable supply of energy. Even assuming the indefinite delay or cancellation of the second Seabrook nuclear unit, the Companies will be able to meet projected peak load throughout the forecast period with only a small (1 MW) shortfall in 1990 reserve margin. The Companies' anticipated generation mix in the first year of the forecast period is:

	Oil/Gas	Nuclear	Coal	Other
Capacity(%)	84.1	15.9	0.0	0.0
Energy(%)	74.3	25.7	0.0	0.0

The forecast generation mix in the last year of the forecast period, however, is:

	Oil/Gas	Nuclear	Coal	Other(Hydro)
Capacity(%)	54.0	24.8	21.0	
Energy(%)	36	34.8[36]	28.6	0.6

The Council is pleased, both with the balanced capacity mix projected for the latter half of the forecast period and the Companies' pursuit of low-head hydro electric energy. The Council is, however,

36 We note that the Companies use NEPOOL capacity factors for projecting the availability of energy from the regions nuclear units. These capacity factors have historically been too optimistic and, thus, we anticipate the nuclear contribution to the energy mix will be slightly lower than projected. See EUA Ex. "L"; the 1982 filing of NEES, Part II, p. 17; 1981 BECo filing, Vol. III, p. I-1.

concerned that E.U.A. has not yet submitted to the Council a comprehensive plan for developing other renewable and local resources such as solar, co-generation, wind and conservation financing. This concern serves as the basis for the Condition of this Decision.

V. DECISION AND ORDER

The Council hereby conditionally APPROVES the Second Long-Range Forecast of the companies and hereby ORDERS:

1. That the Companies meet with representatives of the Council and the Executive Office of Energy Resources within sixty days of the receipt of this ORDER and work with those agencies with due dilligence to back out the use of oil and other expensive sources of energy through economically and environmentally acceptable acquisition of energy produced from cogeneration, renewable resources, conservation and coal conversion.

2. That the Companies file with the Council the construction progress reports, in their entirety, concerning the Seabrook Nuclear Power Project promptly upon receipt of such reports. The Companies are required to insure in their next forecast that all NEPOOL reliability standards are fully met, taking into account potential delays in new units coming on line.

Paul T. Gilrain, Esq.
Hearings Officer

On the Decision:
John Hughes, Chief Economist
Margaret A. Keane, Senior Economist

This Decision was approved by a unanimous vote of the Energy Facilities Siting Council on September 29th, 1982.

Voting in the affirmative: Margaret N. St. Clair,Esq. Secretary of Energy Resources; Bernice McIntire, Esq., designee of the Secretary of Environmental Affairs; Noel Simpson, designee of the Secretary of Economic Affairs; Richard Pierce, designee of the Secretary of Consumer Affairs; Harit Majmudar, Public Member, Electricity; Richard A. Croteau, Public Member, Labor; Thomas J. Crowley, Public Member, Engineering; and George S. Wislocki, Public Member, Environment.

Ineligible to vote: Charles Corkin, Esq., Public Member, Oil; Dennis J. Brennan, Esq, Public Member, Gas.

/s/

Margaret N. St. Clair, Esq.
Chairperson

dated this 11th day of October, 1982.

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

In the Matter of the Petition Fall River Gas for Approval of its Second Long Range Forecast of Gas Needs and Requirements	EFSC 81-20

FINAL DECISION

Paul T. Gilrain, Esq.
Hearing Officer

On the Decision:
Margaret Keane
Staff Economist

I. DECISION HISTORY OF THE PROCEEDINGS

A. Decision

The Council hereby conditionally APPROVES the Second Long-Range Forecast of Gas Needs and Requirements of the Fall River Gas Company.

B. History

The Company filed its Second Long Range Forecast on September 8, 1981, covering the period from 1981-82 to 1985-86. After notice to the public by publication and posting, a pre-hearing conference was held on September 22. No intervenors were present at this meeting, nor did any come forth during the proceedings. No facilities have been proposed for adjudication in this filing. Discovery was sent out in November and received in June. In July of 1982, the present hearing officer was assigned to the instant case and after reviewing the Forecast and the first round of discovery responses, the staff decided that a formal hearing should be held. The hearing was held on September 23, 1982 and later a final set of Information responses was submitted . At the hearing the Company presented Norman Mayer, Senior Vice President as its witness. The record in this case consists of the Second Long-Range Forecast, Staff Information requests and responses thereto, as well as the Hearing Transcript.

C. Background of the Company

The Fall River Gas Company serves approximately 39,000 customers in Fall River, Somerset, Swansea and Westport. Total firm Company sendout in 1981-82 was 6290.5 MMCF. Fall River is the fifth largest gas company in the Commonwealth, accounting for approximately 3% of Massachusetts gas sales. See Table 1 and graphs 1 and 2 for illustration of customer class breakdown.

TABLE 1

FALL RIVER GAS COMPANY

Sendout by Customer Class*
(MMCF)

	1982-83		1985-86	
	Heating Season	Non-Heating Season	Heating Season	Non-Heating Season
RESIDENTIAL				
Heating	2385.5	1151.3	2437.2	1177.4
Non-Heating	46.9	53.6	47.8	41.9
COMMERCIAL	277.5	127.0	278.9	127.6
INDUSTRIAL	1064	931	1072	938
COMPANY USE/UNACCOUNTED	211.5	(93)	215.0	(93)
TOTAL	3985.4	2169.9	4050.9	2191.9

* Compiled from Forecast Tables G-1 through G-5.

II. Compliance with Previous EFSC Conditions

The Council's decision in the review of the Company's Fourth Supplement attached eight conditions to its approval. The conditions and the Company's responses are as follows:

1. "That, in its next filing, the Company document, and quantify, wherever possible, the bases for its judgements and conclusions drawn in regard to conservation and its effects".

   The Company has, both in the context of the forecast and sworn testimony, emphasized the problem of encouraging conservation in a low income service territory with a high percentage of renters. The forecast states that, "Reasons for this (difficulty in detecting any evidence of conservation) may be the large number of tenement houses in our service area. Landlords in these hard economic times are not spending sums of money to insulate or other conservation measures. In most cases, the tenant pays the utility bill so landlords have no incentive to spend money for conservation. Tenants on the other hand, are not about to spend their money on the landlord's property. Conservation under these circumstances is extremely difficult."[1]

   The Company stated that in addition to not having money for insulation, their customers have difficulty paying their bills. The Company testified that as of August, 1982, accounts receivable stood at $2.5 million and half the service department was working on shutoffs.[2]

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1 Forecast, p. 6.
2 Tr., p. 19, 17-22.

2. "That, if significant growth occurs in commercial and industrial load, the Company re-evaluate its methodology of forecasting requirements in its next filing, particularly in regard to the utilization of an average use per customer factor as the principle determinant of requirements".
The Company forecasts growth in the commercial and industrial sectors to be about 1% over the forecast period, and the staff does not view this as significant growth.

3. "That, before the 1981-82 heating season, the Company re-evaluate its methodology of forecasting design season requirements, based on the concerns noted herein, and report to the Council as to any changes made".

The Company states, "Design year is based on 6500 DD. During the past ten years 1971-1981 we have not experienced a design year."[3]

4. "That the Company review its definition of a peak day as 70 degree days and incorporate any changes in the next forecast". The response to this condition is discussed on pages 8-10, <u>infra</u>.

5. "That the Company document the Company judgements which are the bases for its forecast of peak day load".
The response to this condition is discussed on pages 8-10, <u>infra</u>.

6. "That the Company report to the Council on its attempts to approve improve coordination strategy between gas equipment

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3 Forecast, p. 2.

installers and inspectors and the Company, in order to lessen unauthorized conversions to gas".

Prior to obtaining a gas fitting permit from cities and towns, gas fitters are required to obtain a confirmation of available supply from Fall River.

7. "That the company report in its filing its efforts to develop alternatives, other than spot market purchases of LNG and propane, to Algerian LNG".

In addition to spot market purchases of LNG and propane, the Company has the option of returning to 100% of its SNG contract with Algonquin SNG, Inc. See infra at page 13.

8. "That the Company submit to the Council as part of the next filing which is due July 1 an analysis of the cost-effectiveness of displacing insecure and expensive supplemental gas supplies during the heating season with conservation "supply" through the implementation of "zero interest loan programs", the submittal of which has been required by the Secretary of Energy Resources of the Commonwealth pursuant to letter dated April 24, 1981, and Chapter 465 of the Acts of 1980".

A copy of the Company's submittal to the Secretary of Energy Resources was submitted.[4]

4 We note that during the course of the hearing the Company testified that size of the Company's residential class customer base which are low income housing units is second highest in the state (behind Boston) causing a large problem with accounts receivable. It totaled $2.5 million in August alone. See generally: Tr.pp. 17-20, 29-32.

TABLE 2

Normal Year sendout is forecast by customer class using a sales equation:[1]

Residential with Heat[2]

Non-Heating Season

Base use[3] per customer per year X No. of customers X 7 (monthly) = Non heating base

DD in Non-heating season X split year use per customer per DD X Number of customer =[4] Heating use during non-heating season.

Heating Season

Base use per customer per year X No. of customers X 5 (monthly) = Base Use Heating Season

DD in heating X split year use per customer per DD X No. of customers = Heating use based on company operating and sales statistics.

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1 Forecast, p. 3

2. Approximately 58% of Fall River's total sendout is comprised of Residential heat customers, equal to about 75% of total customers.

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

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

A. NORMAL YEAR

A "normal year" is defined as a year that is neither warmer nor colder than average. Normal year is based upon a 10 year arithmetic degree day average. Thus, the Company utilizes a normal year consisting of 6000 effective degree days based on a ten year average from 1971 to 1981.

B. DESIGN YEAR

A "design year" is defined as the coldest year for which a Company plans to meet its firm customers requirements. The Company used a design year consisting of 6500 degree days based on the coldest non-heating season and the coldest heating season over 10 years; these occurred in split years 1978-1979 and 1976-1977 respectively.

In projecting sendout requirements for design year, the Company forecasts a 4% increase over the forecast period. The Company does not however explain the basis for using this 4% figure. Neither does it explain how forecasts of increased sendout requirements are allocated over the design year. This is a serious failing in the Company's forecast which must be corrected. (See: Condition No. 2).

The Council expects future filings to thoroughly explain the basis for design year sendout computations and to forecast design sendout on a seasonal basis or to justify its reasons for not doing so.

C. PEAK DAY

A "peak day" is the coldest day that is likely to occur during a twelve month period. The company uses a peak day of 70 degree days, which is 5 degree days greater than the coldest day in the ten year period from 1971-1981. The purpose of this is to compensate for day of the week, greater wind chill factors and abnormal weather conditions.

The Council's last Decision and Order, EFSC 80-20, conditioned the Company to "review its definition of a peak day and incorporate any changes in the next forecast"[5] The Company witness, Mr. Norman Mayer, Senior Vice President, stated that his 1980 testimony that the Company's historical peak day had been 71.5 degree days was incorrect and the figure should have been 68.5 degree days.[6] The Company believes that the 70 degree day figure remains adequate for forecasting purposes as it has never been exceeded in the service territory.

The Company calculates peak day sendout by multiplying the number of degree days by use per degree day and adding it to base use. In response to 80-20 Condition 5 which required the Company to document the judgements which are the bases for its forecast of peak day load, the Company states that temperature send-out curve points are plotted daily and "any trends noted are monitored on a day to day basis."[7] The Company continues to say that, "this will indicate trends from the median and indicate whether adjustment should be made. This may not be the best mode of forecasting in advance. Past historical figures, DD noticeable trends, plus anticipated customer growth are most reliable information to be used."[8]

It is unclear why the Company did not change its peak day forecast methodology. Five degree days above an historical high degree day was appropriate as a peak forecast when the previous actual high was 65 DD, but not when a colder day, 68.5 DD, occurred. Had the company continued

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5 EFSC 80-20, Condition 4.
6 Tr. p. 8.
7 Forecast p. 6.
8 Forecast, p. 6.

to use its methodology, which planned for a peak day sendout of 7.7% above the historical peak day, the new peak day to be planned for would be 73.8 DD.

The Council is concerned over the Company's apparent inconsistent application of its methodclogy in planning to meet with an adequate margin of safety. Since this matter was the subject of an Order and Condition in our previous decision, we will now require the Company to work with Council staff on a regular basis to remedy this situation.

D. CUSTOMER USE PROJECTIONS

Use per customer is calculated by taking total use for each customer class and dividing by the number of customers within the class. The Company is projecting use per customer to remain constant over the forecast period.[9]

The Company has continually reiterated its opinion that measurable conservation is not occurring in its service territory, thus it believes constant customer use factors are realistic. The Company has not considered the impacts of deregulation, improved appliance efficiency, new construction or price-induced conservation. The Council expects to see a full discussion of derivation of customer use factors, including but not limited to consideration of the impact of price deregulation, conservation, appliance efficiencies and new construction. Since, there has been some difficulty achieving this end in the past, we will again utilize the remedy prescribed in section "C", *supra*.

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9 See: Table 2.

TABLE 3

FALL RIVER GAS COMPANY

Average Annual Use Per Customer[1]

	Residential Classes			Commercial Classes	
	Heating Base Use	Heating Use	Non-Heating	Base Use	Heating Use
HISTORICAL					
1976-77	32.8	.0137	17.0	.0595	.139
1977-78	32.0	.0129	17.3	.0572	.126
1978-79	30.8	.0131	17.4	.062	.130
1979-80	30.9	.0131	17.9	.059	.129
1980-81	30.5	.0127	18.1	.0587(N)	.178
FORECAST					
1981-82	30.9	.0131	18.0	.0595	.130
1982-83	30.9	.0131	18.0	.0595	.130
1983-84	30.9	.0131	18.0	.0595	.130
1984-85	30.9	.0131	18.0	.0595	.130
1985-86	30.9	.0131	18.0	.0595	.130

1 Base Use figures expressed as MCF/year. Heating use figures expressed as MCF/degree day. Compiled from Forecast Tables G-1 through G-5.

N = Normal

E. Conclusions, Sendout Forecast

The Company's forecast of sendout and, based on the record, its knowledge of its customer base is deficient. The Company has been unable to document its forecast of peak day, design year and customer use, despite two rounds of discovery and a hearing at which it was invited to correct any problems in its forecast. The remedial action proposed in Condition number 2 of this decision is aimed at correcting this problem.

At first examination, the Company's problems do not appear troublesome in light of its ample supply of gas as discussed *infra* at pages 13-17; but it is just the adequacy of that supply which is of concern. If the Company cannot forecast gas sendout needs for its service territory accurately, it is difficult to plan for a least cost supply while entering into long term contracts for LNG, Canadian Gas or Algonquin supplies of pipeline and SNG gas. Without such capability, the Company cannot realistically plan for the impacts of the impending decontrol of natural gas prices,[10] and the resultant impact on sendout. It is for these reasons that we attach Condition number 1 to this decision and invite the Company staff to work with us on these issues.

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10 15 USC secs. 3301 *et seq.*

III. Supply Contracts and Facilities

A. ALGONQUIN GAS SUPPLIES

Fall River is a customer of the Algonquin Gas Transmission Company and has contracted for 4385.6 MMCF annually. 3,958 MMCF of this amount is firm delivery under rate schedule F-1, which entitles the Company to a Maximum Daily Quantity ("MDQ") of 14.6 MMCF for a period of 270 days. This contract runs until November 1, 1989. Algonquin rate schedule STB enables the Company to store up to 180 MMCF of natural gas annually during an injection period running from April 1 through October 31. Algonquin has recently upgraded its pipeline system and will be able to provide firm storage return commencing with the 1982-83 heating season. This entitles the Company to an MDQ of 7.1 MMCF up to an annual contract quantity of 427.4 MMCF of that supply. At its contractual MDQ, WS-1 deliveries are available to the Company on 60 days; average daily take is 4.7 MMCF.

Fall River has a contract with Algonquin SNG, Inc., which extends through 1987 for up to 1075 MMCF of SNG. However, pursuant to Section II of the SNG-1 rate schedule the Company has been able to reduce its obligation to 50% of the contract quantity and will take only 563 MMCF annually. The Company has contracted with Bay State for LNG to replace this supply; the Company's witness, Norman Meyer, testified that, "In an emergency situation, we could get back that SNG to cover excess peaks".[11]

11 TR 23-24. The cost of SNG is roughly double the cost of LNG Tr. p. 27; see: 7 DOMSC 1, 62 (1982)

B. LNG

The Company purchases 435 MMCF of liquefied natural gas (LNG) annually from Distrigas of Massachusetts Corporation (DOMAC) under a contract that extends until 1991.

The most recent contract between DOMAC and Sonatrach provides for a delivery schedule of nine ships in the winter and five in the summer as opposed to a previous schedule of eight winter and six summer deliveries. The Company's witness stated that this would help the Company's supply planning. He stated that the Company "won't have to vaporize gas in the summertime and take it."[12] That practice has occurred in the past due to the lack of adequate LNG storage to save the gas delivered in the summer for the winter, when it is needed.

The terms of the DOMAC contract require the Company to take half of the tender within ten days of the ship's unloading, and the next half 24 hours prior to the arrival of the next ship.

Fall River has contracted with Bay State Gas to purchase LNG to enable the Company to decrease its SNG take. Fall River will purchase 350,000 MCF of LNG which it will vaporize. The contract quantity will increase to 1,050,000 MCF in 1986 in line with the Company's expectation that the Algonquin SNG plant will go down at that time. The Company has two LNG vaporizers with a maximum daily design capacity of 20 MMCF and a storage tank with a capacity of 45,000 barrels.

Because of the change in DOMAC shipping schedules mentioned above, and the fact that the company had previously been forced to send out vaporized LNG, the Council is concerned that the Company may have an LNG

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12 Tr. 6-19.

storage problem at the end of the upcoming heating season.

C. Propane

The Company contracts with Petrolane North East for 275 MMCF of propane and 82 MMCF of storage; this contract runs until 1985. The Company also has a letter agreement with Big Horn Propane Supply for 91 MMCF of propane.

The Company has four 80,000 gallon and five 30,000 gallon propane storage tanks. It has two peak shaving LPG facilities, one high- and one low-pressure, with a combined vaporization capacity of 12,000 MCF per day.

IV. Comparison of Resources to Requirements

1. Normal Year

The Company expects to meet total sendout requirements during the forecast period under normal weather conditions as illustrated on Table G-22 in the forecast.[13] Pipeline gas from Algonquin is expected to provide 83% of the non-heating season load and approximately 61% of heating season load. Propane, a small percentage of total send-out, is put into storage during the non-heating season and constitutes approximately 4% of non-heating season load and 12% of heating season load. The supplies outlined here appear adequate to ensure a reliable supply of gas to customers of Fall River Gas during a normal winter.

2. Design Year

The record also indicates that the Company will have sufficient supply to meet the additional requirements expected to occur in a design

13 See Table 3

TABLE 3

FALL RIVER GAS COMPANY

Heating Season Supplies and Sendout[1]
(MMCF)

	1982-83 Total Supply Availability	1982-83 Normal Firm Sendout	1986-87 Total Supply Availability	1986-87 Normal Firm Sendout
PIPELINE				
F-1	1900	1900	1900	1900
ST-1	180	180	180	180
WS-1	357	357	357	357
SNG-1	563	563	549	549
NON-PIPELINE				
Propane	550	336.4	550	384
LNG Storage	745	645	735	285
TOTAL SUPPLY	4295		4271	
NORMAL YEAR REQUIREMENTS		3981.4		4005.0
DESIGN YEAR REQUIREMENTS		4157.1		4166.8

1 Compiled from the Forecast G-22 tables.

year. As seen in the Company's G-22 tables, the Company's total available supply for split year 1982-83 is 6533 MMCF with design year requirements of 6395 MMCF leaving a 2% margin. Because of the ready availability of propane on both spot and contract markets, the Company has the ability to increase resources available to meet a design winter on short notice[14]

3. Peak Day

The record, again indicates that Fall River will have adequate resources to meet forecasted Peak Day sendout during the forecast period. The Company's G-23 table shows 62.6 MMCF available to meet peak day requirements of 46.5 MMCF in 1982-83, this is a sizeable margin.[15]

4. Cold Snap

A "cold snap" is a series of contiguous peak days, such as the two-to-three-week period experienced during the winter 1980-81. Such periods represent particular planning problems for gas utilities that differ from those of meeting the needs of one extremely cold peak day, or of meeting the needs of an entire heating season.

The Company's capability to meet a cold snap can be seen by observing its May 1, 1982 inventory levels. After a very cold 1981-82 heating season and the unexpected April blizzard, the Company had inventories of 111 MMCF of LNG, 23.3 MMCF of LPG, 1,032 MMCF of F-1 gas and 21.7 MMCF of STB gas.

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14 Tr.p. 23

15 See Graph No. 3.

D. Conclusions: Supply Plan

The Company has adequate resources to meet its sendout forecast throughout the forecast period. However, the supply mix of the Company is of some concern. Using imported LNG (including that purchased from Bay State Gas Co.) for 17.3% and expensive SNG for 13.1% of its total winter supply for the duration of the forecast period places too much dependence on expensive or insecure supplies. The Company, unfortunately, has little choice. Its participation in the now indefinitely postponed New England States Pipeline Project[16] is an alternative no longer available to the Company. Additional Canadian gas from Algonquin is available to the Company only on contract terms which the Company considers unfavorable.[17]

V. Decision and Order

The Council conditionally APPROVES the Fall River Gas Company's Second Long-Range Forecast and ORDERS the Company to:

1. Address, in its next supplement, the anticipated effects of price decontrol of natural gas on its forecast of sendout. This analysis should include both projected sendout data for each class, anticipated marketing strategies to ensure both a reliable and least cost supply of gas, and anticipated problems with customer accounts receivable.

2. Meet with Council staff within sixty days of the issuance of the Final Decision and as many times thereafter as the Council

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16 For a description of the project see: 7 DOMSC 51-55 (1982)

17 Tr. p. 22. The revised Algonquin proposal to transport Canadian gas through Niagara on an existing pipeline does not have a storage component as did the NESP. It is the Company's position that it would not be economic for Fall River to purchase this gas at 85% take or pay required load factor without storage.

deems necessary, to discuss the development of an adequate methodology for the forecasting of design year, peak day and customer use factors to be used in future forecast submissions. This forecast must specifically explain the Company's projection of a 4% increase over the forecast period and how it allocates these new requirements over its design year.

3. Submit a combined first and second supplement to its Second Long Range Forecast covering the years 1983-84 through 1987-88 by April 1, 1983.

Paul T. Gilrain, Esq.
Hearing Officer

On the Decision:

Margaret Keane
Staff Economist

This decision was approved unanimously by the Council at its October 25th, 1982 meeting.

Voting in Favor: Margaret N. St. Clair, Esq., Secretary of Energy Resources; Bernice McIntyre, Esq., for the Secretary of Environmental Affairs; Noel Simpson, for the Secretary of Economic Affairs; Richard Pierce, for the Secretary of Consumer Affairs, Thomas Crowley, P.E., Public Member, Engineering; Richard Croteau, Public Member, Labor.

Ineligible to Vote: Harit Majmudar, Public Member, Electricity; Charles Corkin II, Esq., Public Member, Oil.

M. N. St. Clair

Margaret N. St. Clair, Esq.
Chairperson

Dated in Boston this November, 1982.

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

Petition of the Nantucket Electric Company for Approval of its Combined Fourth Annual Supplement and Second Long-Range Forecast of Electric Needs and Resources	EFSC Docket No. 81-28

FINAL DECISION

Lawrence W. Plitch, Esq.
Hearing Officer

The Council hereby APPROVES the Combined Fourth Annual Supplement and Second Long-Range Forecast of the Electric Needs and Resources of the Nantucket Electric Company, hereinafter "the Company" or "Nantucket", subject to the Conditions affixed hereto.

I. INTRODUCTION

A. History of the Proceedings

After a series of extensions, and due to the mutual advantages expected to be realized by both the Council and the Company, Nantucket filed its Combined Supplement and Forecast on March 2, 1982. One principal gain from the delay was the ability to submit, as part of Nantucket's authorized filing, Development of a Master Plan, a just-completed major planning study conducted by Charles T. Main, Inc., under contract to the Company (hereinafter referred to as the "Main report" or the "Main study"). Included in this study were, *inter alia*, lengthy analyses and computer modeling of load projections and power supply plans. This study, supplemented by updated data and narrative responses to the Conditions to the Council's most recent Decision and Order on the Nantucket Electric Company (No. 79-28) constituted the Company's petition.

On June 9, 1982, a conference was held at the Council offices. In attendance were Roger J. Roche, Vice President and Treasurer of the Company, Lydle L. Rickard, President of the Company, John Hughes, Chief Economist for the EFSC and Lawrence W. Plitch, EFSC Hearing Officer. Although the discussion was informal, the meeting did produce a consensus among all concerned that a major decision concerning the Company's future supply plans would need to await both further discussions by Nantucket with other utilities and potential contractors and the upcoming summer peak load figures.

In late August, 1982, the Company was directed to, and did in fact, publish and post proper Notice of its Filing in the appropriate newspapers and locations. No person requested to intervene in the proceeding prior to the requisite deadline. On September 7, 1982, the Council issued a set of 17 Information Requests, designed to update the situation as to the Company's thinking. All but two of the responses were received in the Council offices on October 8, 1982. The remaining two responses, along with information supplementing several of the October 8, 1982, responses, were received on October 14, 1982.

B. Background

Nantucket Electric Company is an investor owned utility that provides electric service to the Island of Nantucket, exclusively. The Company is unique in the fact that it is not in any way interconnected to the New England Power Pool (NEPOOL). As such, it is totally dependent on self-generation. The inherent back-up which is enjoyed by almost every New England electric utility as a result of the pool's interdependence is significantly absent from Nantucket's supply planning. A further distinguishing characteristic of this Company is that it has no industrial class.

The C.T. Main report, prepared in March of 1981, forecasted a summer peak for 1982 of 14,634 KW and annual sales for calendar year 1982 of 56,800 MWH. The Company's supply resources consist of seven diesel generating units ranging in size from 700 KW to 6900 KW, all burning No. 2 fuel oil, which is barged to the Island. Total generating capacity installed is 20.2 MW. Oil storage capacity, now totals 550,000 gallons.

The Company's 1981 Forecast is subject to review criteria as stated in EFSC Rule 62.9 2(a), (b) and (c), which calls for the use of accurate and complete historical data and a reasonable statistical projection method. In its review of a Forecast, the Council determines whether a projection method is reasonable according to whether the methodology is (a) appropriate or technically suitable for the size and nature of the particular electric utility's system, (b) reviewable or presented in a way that results can be evaluated and duplicated by another person given the same information and (c) reliable, that is, provides a measure of confidence that its assumptions, judgements and data will forecast what is most likely to occur. The Council applies these criteria on a case-by-case basis.

Nantucket is one of the smallest electric companies in the Commonwealth, having an annual sales total approximating 1/10 of 1% of that of Massachusetts as a whole. As such, the Council would ordinarily expect a submission in proportion to the size of the Company's forecasting resources and manpower.[1] However, in the instant case, Nantucket has submitted a rather sophisticated long-range supply study. This report was prepared due to the Company's perception that its ability to maintain a satisfactory reserve margin would soon be significantly jeopardized.

Accordingly, the Council has had the benefit of being able to review a more sophisticated forecasting effort than would normally be expected from Nantucket. The result is a forecast methodology that is significantly improved over the Company's previous efforts. The Company

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1 See J.P. Brown, Review of Small Electric Co. Demand Forecasting (April 14, 1981).

is to be commended for perceiving an approaching supply problem and committing a concomitant level of resources to addressing this problem. While Nantucket will not be expected to submit comparable efforts as a matter of course in future filings, it is hoped that the Company's forecasting efforts will be enhanced by its having been involved in a methodology with a sophistication that is typically more appropriate to a company ten times its size.

II. DEMAND ANALYSIS

A. Introduction

The load forecast prepared by C.T. Main was based on several econometric models that were developed for that puppose. The approach utilized was in large measure responsive to Condition Nos. 2-5 of the most recent Council Decision on Nantucket.[2] To this end, the model attempted to find relationships between several variables - *e.g.*, price, population and weather - and sales in both the residential and commercial sectors. The Council is satisfied that the forecasting sophistication and expertise concerns that were the subject of all but one of the Conditions to Decision and Order No. 79-28 have been satisfied. As has been noted previously, the methodological approach of C.T. Main has exceeded the Council's expectations of a company the size of Nantucket. However, there are several assumptions that were used in the modeling effort and conclusions drawn therefrom that merit discussion and analysis.

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2 *See* Appendix A.

B. Residential Sales

The forecasted level of residential sales that results from the Main model is based on assumptions regarding several independent variables. These variables are (1) the total number of residential customers, (2) the number of residential heating customers, (3) the average price of electricity and (4) the number of heating degree days in a calendar year. The degree day variable was simply an historical average (5796.083). The average price of electricity, arrived at by dividing annual revenues by unit sales, was projected to rise, in real terms, at 3% per year through the end of the century. This rate reflects the identical World Bank estimate for the price of imported oil, the fuel on which the Island's electricity is most dependent. These latter two variables do not present a problem for the Council.

The forecasted number of residential and residential heating customers is more troublesome. To derive historical numbers of total residential customers, C.T. Main states that it followed the suggestion of the Council in Condition No. 3(a) of EFSC No. 79-28.[3] To understand the rationale behind that Condition, some explanation is necessay. The Company's 1979 Forecast used as its historical database of residential customers (Table E-1) a summation of every meter billed under each of 5 tariffs, including the Company's water heating (Rate J) and space heating (Rate E) tariffs. Under cross-examination at a hearing on May 23, 1980, Company Vice President Roger Roche conceded that this methodology probably overstated, by hundreds, the actual number of residential customers (Tr., p. 5-7). The Council's responsive Condition

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[3] See Appendix A.

(No. 3(a)) requested that Nantucket eliminate this double-counting by totaling only the meters under domestic Tariffs A, B & R.

In comparing the "historical data base" of the C.T. Main report with Table E-1 of the 1979 forecast, it becomes immediately obvious that the condition's aims were not achieved. While one would expect that the residential customer figures would have decreased with the elimination of the double-counting, they have actually increased in every common year. (*See* Table 1).

Table 1- Residential Customers

	Table E-1/1979 Forecast	C.T. Main "Historical Database"
1970	2719	3460
1971	2923	3617
1972	3169	3177
1973	3374	3862
1974	3572	3990
1975	3689	4077
1976	3814	4132
1977	3892	4239
1978	4094	4391

One explanation may be that the figures in Table E-1 reflected the *average* number of meters in the noted classes (Tr., 5/23/80, p. 6), while the Main report used the "maximum" monthly number of meters for each year. (C.T. Main report, p. 7). In any event, there appears to be an overstatement of the number of residential customers on Nantucket as well as the degree to which C.T. Main was following the Council's "suggestion".

Therefore, the Council Conditions its Approval of this Forecast on Nantucket supplying accurate historical data and reasonable statistical projections of the total numbers of its residential customers in its next filing.

The study's method of calculating the number of residential heating customers was also problematic. Nantucket has never kept separate records of this class. Although the E Tariff is available to electric space heating customers only, the R Tariff is available to electric customers without regard to whether they have electric space heat. As such, the percentage of residential heating customers on Rate R must be estimated. To do this, Main extrapolated from percentage figures for the years 1970, 1975 & 1980 (54.98%, 62.60% and 63.62%, respectively). These percentages were arrived at by manually reviewing the hundreds of meter book entries for the R Class for those years to see if their usage pattern and levels indicated a space heating end-use (Info. Request No. 1, Supp. Response to Question No. 6). Although this method lacks for statistical certainty, it is the best that can be done short of a survey of every customer's end-use array. What is most troublesome, however, is the use of data from 1970. This information sheds little light on consumption trends in a post-embargo era. As such, it is hereby made a Condition to this Decision that in future Forecasts, Nantucket provide historical residential electric heat usage levels for every year from 1979 on. While the computer software capable of scanning each customer's bill for a certain usage level and pattern would be relatively simple, the Council would accept a manual scan for the above noted years, similar to that conducted by the Company for 1970, 1975 and 1980, if that is the responsive method chosen by Nantucket.

A related problem with the C.T. Main forecast of residential sales is the projection of the future rate of growth in the number of residential heating customers. A simple trending of Main's figures for the total number of residential heating customers reveals an annual growth rate of 2.7% (using the Historical Database in Ex. 3.1 of the C.T. Main report) since 1975. However, Main's assumption of an increase of 100 heating customers per year from 1979 to 1990 amounts to an annual growth rate of approximately 8.1% over the ten-year forecast period.

Therefore, it is also made a specific Condition to this Decision that future growth projections in the number of electric space heat customers reflect the historical trends that emerge from the data collection required in the Condition above, or explain any expected deviations from said trends.

The resulting overestimations of the number of residential customers and the percentage of residential customers with electric space heat may have in turn produced an overestimation of one of the C.T. Main report's key dependent variables: residential sales per residential customer. Consequently, this usage factor, which starts at 7.17 MWH/customer/year, and grows at an average annual rate of 3.9% over the next ten years, seems significantly unreliable and fails to meet the criteria set out in EFSC Rule No. 62.9(2)(c). It is, therefore, a further Condition to this Decison that the Company's next filing include updated projections of this usage factor that are reasonably reflective of Nantucket's compliance with the above-related Conditions.

C. Commercial Sales

After several variables, including personal income, heating degree days and the average price of electricity were regressed against commercial sales and rejected as insignificant, Main chose a model that used the number of residential customers as the only dependent variable (Main, p. 8).

While the Council finds no problem with the methodology chosen, _per se_, the reliability of the resultant forecast of commercial sales would, at first blush, seem tainted by its dependence on a set of data that has already been discredited in this Decision.

However, what Main refers to as "residential customers" is, in all likelihood, a fair approximation of the peak number of residential meters in the three most popular domestic classes. That Main may have found a statistical relationship between this index and commercial sales is not suprising, given the the dependence of the Island's commercial activity on seasonal peaks in tourism. In light of the rapid acceleration of commercial development reported on the Island,[4] the Council accepts as reasonable Main's projected growth rate in commercial sales of 6.5% over the forecast period.

D. Peak Forecast

The C.T. Main report used separate econometric models for summer and winter peaks. The former regression uses only the total number of residential customers whereas the latter also found the number of residential heating customers, minimum peak day temperatures and the average price of electricity to have significance.

Again, the statistical significance of the independent variables that were chosen will not be challenged by the Council. If these are the formulae which produced the best historical fit, the methodology would seem impervious, without more, to questions of reasonableness and reliability. However, the Council does feel that the inclusion, as independent variables in an econometric model used to predict future

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4 _See_ C.T. Main report, p. 15.

growth in peak demand, of erroneously defined and labeled factors renders the results of that model subject to close scrutiny.

Although the Main report's forecasts for system peak (summer) for the three years since the study's publication have overstated actual results by 589, 1011 and 834 KW, respectively (See Table 2), there is insufficient evidence to suggest that the projected growth rate in summer peak would be significantly changed if the Main summer peak model were recomputed. Nantucket states as much in response to an information request (See Info. Req. No. 1, Question No. 8).

Table 2

	Main's Forecasted Summer Peaks (MW)	% Annual Increase	Actual Summer Peaks (MW)	% Annual Increase
1980	13.389	5.4%	12.8	0.8%
1981	14.011	4.6%	13.0	1.6%
1982	14.634	4.4%	13.8	6.2%
1983	15.526	4.3%		
1984	15.878	4.1%		
1985	16.500	3.9%		
1986	17.123	3.8%		
1987	17.745	3.6%		
1988	18.367	3.5%		
1989	18.989	3.4%		
Average Annual Increase	.560	4.1%	.500	2.9%

In fact, C.T. Main's average annual increase in summer peak demand over the ten year forecast period is remarkably close to an average of the actual increases in summer peak demand experienced since the report was prepared. In addition, the average annual percentage growth rate is quite similar. Of course, a simple trending of three data points does not produce the reliability of an econometric model. Further, the trend is dissimilar in that there has recently been an increase, rather than the predicted decrease, in peak load demand growth. However, the

Council is satisfied with the fact that this trending did not produce results so contradictory as to impugn the results of Main's model. As such, given the noted caveats, the Council finds the Main forecast of peak demand for Nantucket to be reasonable.

Applying Main's average annual increase for the period 1980-1989 of 4.1% to the actual 1982 summer peak yields expected summer peaks of 14.37 MW in 1983 and 14.96 MW in 1984.

III. SUPPLY ANALYSIS

A. Existing Supply

As mentioned in the introduction, supra, Nantucket's supply mix consists of 7 diesel fired generating plants, ranging in size from 700 to 6900 KW. The Company's installed nameplate capacity totals 20.2 MW. It is reasonable to assume that a Company in Nantucket's situation, i.e., an isolated system without the security of an interconnection to other utilities, would require a reserve capacity equal to the capacity of its largest unit.[5] In the instant case, then, if Nantucket were to lose its largest unit due to, e.g., an unscheduled outage, it would be unable to meet a system peak greater than 13.3 MW (20.2 MW - 6.9 MW). As was noted above, the Island's 1982 summer peak (13.8 MW) has already exceeded this level. This fact obviates any necessity to base opinions of the need for increased energy supply on arguably unreliable projections of future growth of residential customers and usage.

Nantucket states in a supplemental response to one of the Staff Information Requests (Question No. 11) that due to the Company's

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5 See C.T. Main report, p. 47.

"financing position", the Island has experienced a similarly "limited" reserve margin in the past. The Company points out, e.g., that during the period from 1974 through 1977, the Company's reserve margin was below 3.4 MW while the largest unit at that time was 5.6 MW.

The Council cannot, however, countenance an inadequate reserve margin simply because such may have been the practice in prior years. The Council has a statutory responsibility to "ensure an adequate supply of energy for the Commonwealth". To this end, it must require the Company, as a Condition to this Decision and Order, that it come in to the Council within 120 days of this Order with either a detailed report of how it plans to secure, prior to July 1, 1983, a reserve margin equal to the capacity of its largest unit or a satisfactory explanation of why it feels that it will be unable to do so.

It should be added that the Company has indicated that its largest unit (Unit No. 7) had been experiencing "more frequent than normal maintenance intervals and higher than normal maintenance expense" when it was being operated at its 6900 KW rating (Question No. 14). At the suggestion of the unit's seller, Nantucket has more recently been having success operating the unit at a level of 5600 KW. However, this additional reduction in operating reserve only compounds an already tenuous situation.

B. New Supply Options

One of the principal objectives of the C.T. Main study was to investigate and analyze the feasibility of various alternative approaches to meeting the anticipated supply shortfall. These alternatives consisted primarily of variations on two ideas: (1) laying a submarine cable between Nantucket and Cape Cod, and (2) increasing the self-generation capability of the Company. The various cable options included different electrical configurations and alternative routes. The basic on-site options were either additional diesel units or new combustion turbine units. The Main report performed an excellent job of costing out the various scenarios and providing Nantucket with a blueprint for action. The study's conclusions, based on planning cost estimates only, are summarized in Table 3.

Table 3

Option	Installed Cost
I. Nantucket-Hyannis cable route, 23 kV, 28.4 miles	
A. Four single-conductor cables	$39,400,000
B. Two three-conductor cables	$26,300,000
C. One three-conductor cable	$11,600,000
II. On-site Generation	
A. Two five MW combustion turbines	$285,000,000
B. Two five MW diesel generators	$302,000,000

The study indicates that the cable "may be the economic preference" (Main report, p. 4) but cautions that this conclusion depends on both the actual prices charged by the cable's manufacturer and the negotiated cost of purchase power from Commonwealth Electric. Without providing extensive details as to the various assumptions and contingencies that were considered by Main, it is important to note that the study found, inter alia, that a cable costing between $17 and $20 million, coupled with 5 cent per KWH energy, broke even with a plan to install the additional diesel generators.

Since the issuance of the Main study, Nantucket has conducted extensive discussions with Commonwealth Electric representatives and has also obtained firm prices for the most feasible cable configurations. The result of these discussions, as offered in response to Information

Request No. 1, Questions 9, 10 and 11, is that the only viable supply option now under serious consideration by the Company is the installation of additional diesel generation.

Through further discussions with Vice President Roche, the staff has learned that the diesel generation option is at present being "actively pursued". Although Mr. Roche "hopes" to have the additional generation in place by next summer, he is "certain" it will be operational within 2 years. As stated in Condition No. 5, the Company's plans need to be on firmer footing. The Council is aware that the contracting for and preparation of the Main report had the effect of delaying a Company decision on this issue longer than would have been the case had the Company decided to pursue the solutions to this problem internally. Be that as it may, the time for expeditious implementation has arrived.

C. Private Wind Power

Condition No. 1 to the Council's last Decision and Order on Nantucket (EFSC No. 79-28), requested information from the Company concerning wind generation on the Island and the buy back rate in effect for purchasing power from these self-generators.[6] This information has been provided and the Condition has been complied with (*See* Table 4).

Table 4

Period	$/KWH
August - October, 1981	.0744
November, 1981 - January, 1982	.0744
February - April, 1982	.0752
May - July, 1982	.0688
August - October, 1982	.0674

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6 *See* Appendix A.

During 1981, there were six wind powered self-generators installed on the Island. The Company was able to purchase 3527 KWH from four of these units, while the remaining two units were used to reduce their owners' KWH requirements. In response to Information Request No. 1, Questions 1 and 2, Nantucket described the operating results of the seven established wind-machines (one was added in early 1982) as "erratic". One machine snapped a blade in December, 1981, and has been down since then. Four other machines that have not functioned since April, 1982, are the focus of warranty actions by their owners. More recently, three 25 KW units owned by Nantucket Windfarms came on line in August, 1982. There is the possibility that if these machines prove successful, this company would install an array of 120 identical machines.

While the Council firmly believes that renewable resources such as these wind machines should be actively encouraged and pursued by the Company, at this time wind power generation on Nantucket is not seen to be of sufficient reliability to in any way postpone the Company's efforts in seeking its own additional firm generation.

IV. ORDER

The Council hereby APPROVES the Combined Fourth Annual Supplemental and Second Long-Range Forecast of Electric Needs and Resources, subject to the following Conditions:

1. That the Company, in its next filing, supply accurate historical data and reasonable statistical projections of the total number of its residential customers.
2. That the Company, in its next filing, provide historical residential electric heat usage levels for every year from 1979 on.

3. That the Company, in its next filing, include future growth projections in the number of electric space heat customers that reflect the historical trends that emerge from the data collection required in Condition No. 2, or explain any deviations from said trends.

4. That the Company, in its next filing, include updated projections of its "residential sales per residential customer" usage factor that are reasonably reflective of the results of Nantucket's compliance with Condition Nos. 1-3.

5. That the Company come in to the Siting Council within 120 days of the date of this Decision with either a detailed report of how it plans to secure, prior to July 1, 1983, a reserve margin equal to the capacity of its largest unit or a satisfactory explanation of why it feels that it will be unable to do so.

Lawrence W. Plitch, Esq.
Hearing Officer
October 15, 1982

This Decision was approved by a unanimous vote of the Energy Facilities Siting Council on October 25, 1982, by those members and representatives present and voting.

Voting in favor: Margaret N. St. Clair, Esq., Secretary of Energy; Bernice McIntyre, Esq. (for Secretary John A. Bewick); Noel Simpson (for Secretary George Kariotis); Richard Pierce (for Secretary Eileen Schell); Harit Majmudar; Thomas J. Crowley; and Richard A. Croteau.

Ineligible to Vote: Charles Corkin, II.

November 29, 1982
Date

M. N. St. Clair
Margaret N. St. Clair, Esq.
Chairperson

APPENDIX A

"The Council approves Nantucket's 1979 Supplement subject to the following conditions:

1) That the Company inform the Council in is next filing of the buy-back rates it has negotiated with the wind-powered self-generators on the Island, and provide a summary of the performance of these and other self-generators.

2) That the Company provide data on its residential customers in the following manner:

   a) for 1970 and 1975-1980, the number of customers and average kwh use per customer for those on rates A, B, and R, including an estimate for each year of the number of these customers who pay a minimum monthly charge during the winter months.

   b) for 1970 and 1975-1980, the numbers of customers and average kwh use per customer for those on rates E and J, including an estimate for each year of the number and use of those customers who are in fact commercial customers.

   (Data used in Annual Report to the Massachusetts Department of Public Utilities are acceptable.)

3) That the Company's Table E-1, which shows total residential sales, be modified as follows:

   a) data in the column "Number of Customers" should be computed by counting the number of A, B, and R meters.

   b) data in the column "Average Use per Customer" should be computed by dividing sales to all customers on rates A, B, R, E and J by the number of A, B and R meters.

c) to the extent possible, commercial customers and use on rates E and J should be reported on Table E-3.

4) That the Company continue to monitor land use and growth policies, the use of wood stoves to supplement electric heating and other conservation, penetration of air conditioning into the commercial sector, self-generation, and tourism and relate these factors to the preparation of the sales and peak forecasts. The Council expects these relationships to be explained in the forecast narrative.

5) That the Company further study its seasonal commercial class sales in order to develop a relationship between the commercial class and tourism."

COMMONWEALTH OF MASSACHUSETTS
Energy Facilities Siting Council

Petition of the Fitchburg Gas & Electric Light Company for Approval of its Second Long Range Forecast of Gas Needs and Requirements, 1981-1986	EFSC No. 82-11A

FINAL DECISION

Paul T. Gilrain, Esq.
Hearing Officer

On the Decision:

Margaret Keane
Staff Economist

I. Introduction and History of the Proceedings

A. Decision

This Decision CONDITIONALLY APPROVES in part, and REJECTS in part the Second Long Range Forecast of Gas Needs and Requirements of the Fitchburg Gas & Electric Light Company.

This decision is divided into five sections. The first section contains an introduction and a procedural history. The second section lists the conditions attached to the Council's decision on the previous filing by the Company. The third section describes and reviews the Company's sendout forecast. The fourth section describes and reviews the forecast of supplies. The fifth section contains the Order and Conditions for next year's filing.

B. History of the Proceedings

The Company filed its Second Long Range Forecast on September 23, 1981, covering the split years 1981-82 to 1985-86. After notice to the public by publication and posting, a pre-hearing conference was held on October 26, 1981. No intervenors were present at this meeting, nor did any come forth during the proceedings. No facilities have been proposed for adjudication in this filing.

Staff information requests were sent to the Company on May 28, 1982. Responses were received on June 21, 1982. A hearing was held on August 6, 1982 and a final set of Information Responses was received on August 12, 1982.

C. Background

The Fitchburg Gas & Electric Light Company ("Fitchburg" or "the Company") serves approximately 14,000 customers in Fitchburg and the towns of Ashby, Townsend, Westminster, and Gardner. Total firm Company

Table 1

Fitchburg Gas Company

Sendout by Customer Class
(MMCF)

	1982-83		1985-86	
	Heating Season	Non-Heating Season	Heating Season	Non-Heating Season
RESIDENTIAL				
Heating	905(.52)	407(.48)	970(.23)	436(.48)
Non-Heating	107(.06)	71(.08)	114(.06)	76(.08)
COMMERCIAL	332(.19)	149(.18)	355(.19)	160(.18)
COMPANY USE/ UNACCOUNTED	139(.08)	18(.02)	148(.08)	20(.02)
INDUSTRIAL	240(.14)	205(.14)	258(.14)	219(.24)
TOTAL	1723	850	1845	911
	2573		2756	

NOTE: Numbers in parentheses denote percentage of toal seasonal sendout. Figures may not add up to 100 due to rounding.

sendout in 1980-81 was 2,318 MMCF. Fitchburg is the tenth largest gas Company in the Commonwealth, accounting for less than 2% of Massachusetts gas sales. Fitchburg's annual gas sales are broken down as follows: residential with gas heating 50%, residential without gas heating 7%, commercial 19%, industrial 17%. See Table 1. These percentages are expected by the Company to continue through the forecast period. It sells roughly twice as much gas in the heating season as in the non-heating season. In 1980-81, 26% of sales were interruptible; in 1985-86 this percentage is forecasted to decline to 21%. Between 1978 and 1981, the Company's firm sales grew 23% on a weather-normalized basis as a result of gas conversions and new construction. The forecast discussed in this decision projects a total growth rate of 1.09% in total firm sendout during the five year forecast period.

II. PREVIOUS EFSC CONDITIONS

The Council's decision in the review of the Company's Fourth Supplement attached eight conditions to its approval. They were:

1. That, in subsequent filings, all numerical factors which were used in deriving the forecast of seasonal sendout on Tables G-1 to G-5 be described.
2. That the Company re-evaluate its methodology for forecasting requirements, including its method of forecasting the number of customers in each class, load requirements for each class and customer use factors.
3. That, in the next filing, the Company discuss how its design standard compares to the coldest non-heating season and heating season in the past 30 years.

4. That, in its filing, the Company address in detail the status of the Boundary Gas Project, the level of risk involved in relying on the Project as a supply source for new load additions, the level of confidence the Company has in its approval and timely delivery, and the Company's contingency plans in the event the project is delayed or disapproved.

5. That, before August 1, 1981, the Company report to the Council how it will supply the seasonal and peak day volumes originally assumed to be available from the Boundary Gas Project in the heating season of 1981-82.

6. That, in its next filing, the Company describe the likelihood and effects of a loss of a significant portion of its current Interruptible market, and report on its plans to address such an event.

7. <u>That, in its next filing, the Company describe the extent of its contingency planning, and if and how such planning protects against the above mentioned supply uncertainties</u>.

8. <u>That the Company submit to the Council as part of the next filing which is due July 1 an analysis of the cost effectiveness of displacing insecure and expensive supplemental gas supplies during the heating season with conservation "supply" through the implementation of "zero interest load programs", the submittal of which has been required by the Secretary of Energy Resources of the Commonwealth pursuant to letter dated April 24, 1981, and Chapter 465 of the Acts of 1980.</u>

The Company has attempted to comply with these conditions in its Forecast. The Company's efforts to comply will be discussed at appropriate points in the Forecast of Sendout and Supply Plan sections of this Decision.

III. FORECAST OF SENDOUT

A. Review Criterion

The Council employs three criterion in its evaluation of gas company forecasts. They are reviewability, reliability, and appropriateness. A methodology is reviewable if a Company's submission to the Council contains enough information to allow a full understanding of the Company's methodology such that the results can be evaluated and duplicated by another person given the same information. In this proceeding, a number of contradictions exist between statements made in the Company's forecast, in its discovery responses and in its hearing testimony. The level of documentation necessary to judge a forecast reviewable has not been achieved in this proceeding.[1]

A methodology is reliable when it ensures confidence that the assumptions, judgements and data forecast what is most likely to occur. Contradictory statements regarding growth levels, conversion policies and sendout requirements, as well as low peak day and design year figures, do not impart confidence in the reliability of this forecast.[2]

As the two previous criteria have not been met to the Council's satisfaction, the issues of whether the forecast is appropriate or technically suitable for the Company at hand cannot be determined from a review of the Company's filing and, will not be a primary concern of

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1 Infra, 6-9.
2 Infra, pp. 7, 11.

this decision.

B. Normal Year

A "normal year" is defined as a year that is neither warmer nor colder than average. The Company took a 25 year arithmetic average of actual degree day data and arrived at a normal year of 6530 degree days. This is not an inappropriate calculation. However, the Company, referring to problems with the forecast methodology, stated that "6530 degree days were used instead of a more representative 6,711 degree days for the Fitchburg area."[3] The Company did not provide documentation for the assertion that 6711 is more representative in light of the fact that the average of the past five years has been 7187 degree days this may be seen as a positive change. However, complete documentation for the selection of this critical figure is requested in the future. The Council does note the Company's statement that, "Our next forecast will contain revisions to reflect the needed change."[4]

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

Base load and space heating increments were calculated from an analysis of firm gas sendout during split year April 1, 1980 to March 31, 1982, according to the Company. The nature of this analysis was not specified. Earlier in the Forecast the Company also stated that it used linear regression analysis in this calculation.[5] The Company witness, Michael Minkos, Manager of Energy Supply, stated that he calculated base use and base heating correlations; he did not explain the variables used

3 EFSC 81-11A, Response 5, emphasis added.
4 Forecast: Methodology, forecasting.
5 Id.

in the analysis or the number of years of data used. He also stated that, "On an annual basis we use July and August and divide it by two... We feel those are the two months there's no heating on any gas use."[6] In any event, base load heating increments are absolutely essential building blocks in any forecast. The Council has approved use of July and August sendout figures as an acceptable method of forecasting base use in several cases.** However, the Company should describe the exact nature of the regression analysis used and specify how it was used in the forecast. Regardless of what methodology the Company uses, the Council expects thorough and concise documentation of the derivation of these critical figures in all future filings.

After arriving at figures for base load and heating increments, the company calculated Test Year Firm Annual Gas Requirements of 2,064,082 Mcf based on sales from April 1, 1980 to March 31, 1981. The Company states that, "total sendout is then calculated using the base load and space heating increment." Base use and space heating increments are multiplied by projected number of customers to arrive at total sendout. (The connection between Test Year Firm Annual Gas Requirements and total sendout is not explained in the Forecast). From there, base load and space heating increments are expressed as percentages of total year sendout, and these percentages are expected to remain constant for each year of the forecast period.

The Company has set a net 3% annual growth as a goal for total system sendout. In the forecast, this figure is multiplied by the Test Year Firm Annual Gas Requirement to arrive at an annual increase in sendout of 61,922 Mcf. However, the Company's witness, in his most

6 Tr. pp. 27-29.
7 7 DOMSC 164 (Commonwealth).

Table 2

Fitchburg Gas Company

Average Annual Use Per Customer

	Residential Classes Heating Base Use	Residential Classes Heating Heating Use	Non-Heating
HISTORICAL			
1976-77	33.9	.0135	29
1977-78	32.5	.0131	30.4
1978-79	32.7	.0128	30.8
1979-80	33.1	.0133	33.7
1980-81	31.2	.0146	39.9
FORECAST			
1981-82	31.3	.0165	45.6
1982-83	31.2	.0167	47.5
1983-84	31.3	.0169	48.9
1984-85	31.3	.0172	49.9
1985-86	31.3	.0174	51.0

NOTE: Base use figures are expressed as MCF/year. Heating use figures are expressed as MCF/degree day.

recent testimony, stated that the Company has changed this assumption and said "Fitchburg's current policy is zero growth," and that "our current limitations are not total supply, but peak day and peak hour availability, we are very conscious of that and that's the reason we are now on a zero growth until we either get an increased pipeline supply or a firm storage."[8] The implication of this change in growth projections for supply planning will be discussed more later in this decision. It should also be noted that the 3% annual net growth assumption was not based upon an analysis of number of customers and usage per customer in the various classes. The Company states in response to Staff Information Request No. 5, that , "A good portion of this [3%] growth would be in the residential heating program." Exactly how much was not specified. However, as of August 10, 1982 the Company had no customers waiting to be converted, information consistent with the Company's current zero growth policy.

After factoring growth into the total sendout forecast, the Company divided total sendout for the year being forecasted into base use and space heating increment using the percentages previously established.[9] The split year 1980-81 is analyzed to determine the percentages of total sendout which were industrial, commercial, residential with gas heat, and residential without gas heat. These customer class assumptions are assumed to remain constant over the forecast period. This method considers neither changes in number of customers, nor in use per customer. See Table 2. This is inconsistent with Fitchburg's assertions that it expects much of the forecasted growth to be in residential

8 Tr. pp. 13-24, 74.

9 See Table 1, numerical factors provided in response to EFSC 81-11A condition 1.

conversion to gas heat, and that usage per customer in this class will increase substantially over the forecast period. However, the Company's witness stated at the August 6, 1982 hearing that:

> "We will be changing our methodology for we don't anticipate an increase in use per customer. We anticipate it staying equal or showing a slight decline as conservation takes hold. But the methodology which you see here is incorrect to the point where it is just done on a straight mathematical basis by using total, taking sendout, dividing percentage-wise against the classes for historical days use and dividing what we felt would be the estimated number of customer in a particular class."[10]

This explanation is unsatisfactory in light of EFSC 81-11A Condition 2 stipulating that the Company re-evaluate its methodology for forecasting requirements, including its method of forecasting the number of customers in each class, load requirements for each class and customer use factors. In its next filing, Fitchburg should explain how it has derived its projections of number of customers and usage per customer, by class, and how it uses these in its overall forecast of sendout. If it chooses not to use such a methodology, it should explain why not, and explicitly state why its methodology is preferable. Condition No. 1 addresses this issue.

C. Design Year Sendout

In response to Condition No. 3 in the last Council decision, Fitchburg provided 17 years of weather data for its area. This data shows that the average of the last five years has been 7157 degree days (DD), 627 degree days above the 6530 DD which Fitchburg has considered to be normal for forecasting purposes. The Company has since indicated that the figure for a normal winter should be 6711 degree days, instead of 6530 DD.[11] In fact, 7157 DD is only 0.4% less than the 7183 DD which

10 Tr. p. 12.
11 See: infra at 15.

Fitchburg considers to be design. Fitchburg's design criteria has been exceeded twice in the last seventeen years. The Company needs to adjust its definition of normal and design years to reflect its experience over the last five years. It should describe such adjustments in its next forecast, or explain why it has not done so. (See: Condition No. 1).

If a design criteria of 7440 DD is used (this is the actual figure for Fitchburg in 1977), rather than the Company's design figure of 7183, design sendout for 1982-83 is increased by 72 MMCF, and for 1985-86 by 78 MMCF.

D. Peak Day Sendout

Peak day sendout is projected to grow by 2-3% each year during the forecast period. The Company uses 66 DD as its design criteria for peak days. The Company justifies its approach as follows: "This number [66 DD] was selected from a statistical approach. Using historical data 66 DD is simply the probability of that Degree Day occurring once in 25 years."[12]

The purpose of projecting peak day sendout is to estimate the maximum one day sendout that the Company must plan for. For Fitchburg to hold to a 66 DD figure when it recently experienced a 70 degree day raises questions about its "statistical approach". In its next filing, the Company should make adjustments in its peak day design criteria, or explain to the Council why it has not. (See: Condition No. 1).

If a design criteria of 70 DD is used, rather than 66DD, peak day sendout for 1982-83 is 20,510 MMBtu,[13] and it must be remembered that

12 Forecast p. 3.
13 Second Information Responses, No. 2.

this represents supply planning on the basis of actual experience with no contingencies built in.

The Company's projected peak day sendout, based on a 66 degree day, for 1982-83, is 20.7 MMCF. The Company witness did state, in response to questions on whether peak would be lowered due to less system growth that, "This year I believe it (peak) would be close to the 20.7 but again it would probably be fair to say it might be a little less." (Tr 76).

E. Conclusions: Sendout Forecast

The Company's forecast of sendout is not reviewable, is not the product of the application of a reliable methodology and is an inadequate basis for supply planning. In its calculation of both design peak and design year the forecast design is below actual experience. The company, in effect, has told the Council in written submission that they plan to have less gas available on winters' coldest days than has been needed in the recent past. This can in no way be approved by the Council as, "... a projection of... gas requirements... based on substantially accurate historical information and reasonable statistical projection methods." MGL Ch. 164 sec. 69J. Therefore, the Council Rejects the Company's forecast of sendout.

IV. Supply Contracts and Facilities

A. Pipeline Supply

The Company has a long term contract expiring in November 1988 with the Tennessee Gas Pipeline Company (hereinafter "Tennessee") for the delivery of up to 7.6 MMCF/day of pipeline gas up to an annual volumetric limitation of 1131 MMCF. The Company receives 100 MMCF of storage gas; 50 MMCF from Consolidated and 50 MMCF from Penn-York storage. The Penn-York storage gas is available under a firm transportation contract with Tennessee at up to 0.5 MMCF/day[14] and the Consolidated up to 0.5 MMCF/day on a best efforts basis.

B. LNG

The Company has operated under a long term contact with Bay State Gas Company (hereinafter Bay State) for the purchase of LNG. This contract, executed in 1978, provides for 125 MMCF of firm and 40 MMCF of optional LNG. The contract has been amended in each of the past two years to provide additional LNG. In the 1981-82 heating season the amended contract provided for an additional 105 MMCF firm and 35 MMCF of additional quantities. Due to delays in the Boundary gas project, the Company has recently amended the Bay State contract to provide for 250 MMCF firm and 75 MMCF optional of LNG.

The Company leases on-site LNG storage and vaporization facilities in Westminster, Mass. Storage capacity is limited to 4.17 MMCF, which represents less than one day of peak sendout. Maximum sendout during the 1980-81 heating season was 4.9 MMCF. The Company's peak day LNG

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14 Tr. p. 65.

sendout capability is 7.2 MMCF. For maximum peak day sendout, eight trucks, carrying 880 MMBtu each, are necessary in a 24-hour period. LNG will remain a significant source of peak day supply even after the Boundary Gas Project commences supply of natural gas.

PROPANE

The Company has long term propane supply contracts with Petrolane, Inc. and the C.M. Dining Corporating extendion through March 31, 1985. These contracts provide for 110 MMCF of firm supplies and 72 MMCF of optional quantities.

The Company owns a propane/air Peak Shaving facility in Lunenburg, Mass. with a storage capacity for 25.4 MMCF and maximum daily design capacity of 7.2 MMCF.[15] Reliance on propane is expected to decline once the Boundary Gas Project comes on line.

D. Boundary Gas

Fitchburg has signed a precedent agreements with Northeast Gas Markets, Inc. to receive up to 1,000 MCF/day of Canadian Gas as part of the Boundary Gas Project. This gas will be used to fill 250,000 MMCF of storage, contracted for with the Penn-York Energy Corporation, and to supply gas during the heating season.

The Company initially forecasted that the Boundary Gas Project would be on line by November 1982. The Company now expects delivery of these supplies to commence in the fall of 1984 and has amended its contract with Bay State Gas to provide for additional volumes of LNG to compensate for this delay.[16] The Company has also arranged to inject

15 All of the Company's previous filings indicated that maximum LPA capacity was 6.0 MMCF/day, including the present filing. Under cross-examination at the hearing, Company witness Michael Minkos testified that 7.2 MMCF/day is the correct figure.

16 See: supra at 12.

additional pipeline gas into the Penn-York storage fields. Approximately 86,000 MCF of storage gas, above and beyond the 100,000 MMCF storage previously available, will be available to the Company on a best efforts basis.

E. Additional Supplies

Fitchburg has formed a wholly owned subsidiary, Fitchburg Energy Development Company (FEDCo) which is engaged in exploration for natural gas. This venture has enjoyed limited success. Production is approximately 13 MCF/day at the present time. The Company expects to produce 20 MCF/day resulting in the supply of 4 MMCF per year during the forecast period. This represents approximately 0.2% of annual firm sendout.

F. Conclusions - Supply Plan

Prior to analyzing the ability of the Company to meets its forecast needs, we must note that its forecast has been rejected and has been judged unreliable. The following analysis of the Company's ability to meet firm needs on peak day, design year, and so called "cold snap" periods is based on the best actual historical data available to the Council at this time. This analysis does not address the Company's ability to meet design needs as there is no acceptable forecast of them.

1. Peak Day

Fitchburg has experienced an actual peak day of 70 DD.[17] To meet the needs of its customers on that day, the Company would need to send out 20.7 MMCF of gas.[18] The Company's combined maximum sendout capacity is 22.5 MMCf/day and allows for an 8% reserve over actual

17 Tr. p. 49
18 This calculation utilizes the forecast methodology rejected in Part II, supra. No other method is available.

Table 3

Fitchburg Gas Company

Comparison of Resources Available to Meet Actual Peak Day[1]
(70 DD)

Source	Capacity MMCF/Day	Capacity Needed on Peak MMCF/Day	% Capacity on Peak
Tennessee	7.6	7.6	100
Firm Storage Return	0.5	0.5	100
LPA	7.2	5.4	75
LNG	7.2	7.2	100
	22.5	20.7	92% (weighted average)

1. Source Tr.pp. 65 *et seq.*, Forecast Table G-23, Tr. p. 49

historical peak.[19] Although this appears adequate at first blush, the supply mix of the Company causes concern over the reliability fo the Company to meet its firm customers needs on the winter's coldest days. See Chart 1 and Table 3.

Fitchburg supply mix at peak consists cf: one LPA plant with 3.5 days of storage at maximum capacity; an LNG facility consisting of two vaporizers, each with a maximum operating capacity of 7.2 MMCF/Day, but because of operational problems is only capable of a peak sendout of 7.2 MMCF/Day; and, pipeline supplies. As Table 3 shows, the sources each represent approximately 33% of peak sendout. The Company testified that, in the event of an unscheduled interruption of any of these facilities on a peak day, the Company, "... would probably have to institute some type of curtailment plan within our system."[20]

The Council is concerned that the Company apparently does not have in place a contingency plan with either Boston Gas, with which it has an interconnection in Lunenburg, or with Tennessee for emergency gas in such a contingency.[21] We understand the problems that smaller gas companies such as Fitchburg must confront in constructing and maintaining reserve peak shaving capacity for use on rare occasions. To the extent economies of scale allow the larger gas companies, such as Boston, Commonwealth and Bay State to maintain such reserves, the Company should consider utilizing such capacity through interconnections.

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19 Tr. p. 72

20 Tr. p. 17.

21 Remedies may also be sought from the FERC. See 15 USC secs. 717 <u>et seq.</u>

Table 4

Fitchburg Gas Company

Heating Season Supplies and Sendout

	1982-83 Total Supply Available	1982-83 Normal Firm Sendout
PIPELINE		
CD	1131	1131
Storage	177.7	144.2
NON-PIPELINE		
Propane	204.6	164.8
LNG Storage	429	240
FUTURE SOURCES		
Boundary Gas		
TOTAL SUPPLY	2042.3	
NORMAL FIRM SENDOUT REQUIRED		1723
DESIGN YEAR REQUIREMENTS		1908

NOTE: Boundary Gas volumes have been deleted from the 1982-83 heating season LNG volumes have been increased in order to reflect the Company's amended contract with Bay State as provided in Information Response 81-5.

2. Design Year

As was discussed in Part II. C., *supra*, the Company forecasts a design year of 7183 DD when the *actual* design year over the last five years has 7440 DD, having a margin of 0.4%. The Company has projected that it will have available 3371 MMCF to meet design conditions. Of this total 2634 MMCF is pipeline gas or winter storage gas; 50 MMCF is purchased LNG from Bay State; and 213 MMCF is propane. Removing Boundary Gas Supplies from the Company's G-22 tables shows Fitchburg to be approximately 31 MMCF short of design requirements for the '82-'83 heating season. To replace these volumes the company has entered into a firm contract for LPG with Dome Petroleum and the Company appears to have sufficient resources necessary to meet their historical average normal year with any margin for design (above 0.4%) to be met with LPG or LNG, whichever is less expensive.[22]

3. Cold Snap

In our discussion of the Company's ability to meet peak day requirements[23] we noted that the Company operates near full capacity during such weather. During a "cold snap", defined as a number of consecutive days at or near peak, the Company would operate its LPA and LNG plants at almost full capacity. The Company would be reliant on trucks for LNG after the first 18 hours and would be in a similar situation with regard to LPG after 4.6 days (assuming 100% inventory levels on the first cold day). This is a troublesome situation, but not insoluble. The Company should have a firm, written standard operating

22 We note that this will apparently be the case for the upcoming heating season. See Table 4.

23 See part III F.1, *supra*.

procedure to follow in the event of an unscheduled capacity outage during a cold snap, which should include a discussion of utilizing its Lunenberg interconnection.

4. Conclusions

Fitchburg can meet actual historical peak day, year and cold snap criteria with available resources. The Council is however concerned over the lack of capacity reserve during cold weather, and the lack of LNG storage. We are sympathetic with the Company's economic situation as pertains to new construction[24] but feel strongly that the Company must have reserve capacity available to it of at least 7.2 MMCF/day. (The size of both the LPA and LNG daily maximum sendout), and we so condition this decision.

IV. DECISION AND ORDER

The Council hereby RFJECTS the sendout forecast of Fitchburg and APPROVES CONDITIONALLY the Company's supply plan, and now ORDERS:

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

This forecast should specifically include:

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

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24 Discovery Response No. 8.

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

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

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

Paul T. Gilrain, Esq.
Hearing Officer

On the Decision:
Margaret Keane
Staff Economist

This decision was approved unanimously by the Council at its October 25th, 1982 meeting.

Voting in Favor: Margaret N. St. Clair, Esq., Secretary of Energy Resources; Benrice McIntyre, Esq., for the Secretary of Environmental Affairs; Noel Simpson, future Secretary of Economic Affairs; Richard Pierce; for the Secretary of Consumer Affairs, Thomas Crowley, P.E., Public Member, Engineering; Richard Croteau, Public Member, Labor.

Ineligible to Vote: Harit Majmudar, Public Member, Electricity; Charles Corkin II, Esq., Public Member, Oil.

Margaret N. St. Clair, Esq.
Chairperson

Dated in Boston this ____ day of November, 1982.