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**ECONOMIC FEASIBILITY STUDY OF  
TOTAL ENERGY SYSTEM OPTIONS FOR THE  
MASSACHUSETTS INSTITUTE OF TECHNOLOGY**

by  
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and  
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of  
**The Nuclear Engineering Department  
of the  
Massachusetts Institute of Technology  
for the MIT Physical Plant Department**

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May 15, 1978

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Abstract

A preliminary investigation into the economic feasibility of installing a Total Energy System (TES) at the Massachusetts Institute of Technology (MIT) was made, accompanied by recommendations for further course of action. The study evaluated three plant designs; a steam turbine, a diesel system, and a gas turbine system. All three TES designs were evaluated on the basis of their capability of supplying the total annual MIT steam and electrical requirements. A system's economic feasibility is determined in terms of the annual rate of return on invested capital. The results of this investigation indicate that only the diesel system is superior to the current system consisting of a plant which supplies steam only with electricity being purchased from the Cambridge Electric Light Company. The diesel system would permit savings of \$958,962 annually over the costs of the present plant (in 1977), returning 13.9% on its capital investment. The steam plant would lose \$203,804 annually (-1.6%) and the gas turbine would lose \$688,949 annually (-16.6%). The importance of this analysis is the resulting relative rankings of the various alternatives, rather than the absolute value of the estimated economic savings (or costs). A preliminary study such as this employs a greatly simplified financing plan and does not account for several important factors such as the costs of backup capacity and inflation. In addition, an optimized financing and capacity addition scheme would be expected to increase the estimated savings of any TES substantially.

From this examination it is seen that primary attention for future TES alternatives for MIT should be devoted to that using a diesel power plant, since all of the alternatives were evaluated on a consistent basis, with the diesel powered system resulting as the most economical alternative.

## 1. Introduction

Due to the rising cost of electricity, it has become common for industries and institutions to consider generating their own electricity and steam to meet their total energy needs. Such systems have become known as Total Energy System (TES). The physical plant at the Massachusetts Institute of Technology is currently considering such a system. The present plant supplies the total steam demand of the Institute, and electricity is provided via purchases from the local utility, Cambridge Electric Light Co.

In searching for the most economical method to supply the MIT community with energy, three TES designs have been evaluated. However, before these designs can be analyzed, the load model for MIT, upon which all systems are evaluated, must be discussed. In this study the electrical and steam load growth for the Institute was projected to the year 2000 in order to determine the required capacities of the TES alternatives. Several proposed electric rate schedules that may be in effect during the TES operation were reviewed in order to analyze the effect of the anticipated "time of day" pricing plan on TES costs. Finally, the method of economic analysis of the TES alternatives is presented so that each plan may be evaluated on the same basis.

The alternatives evaluated are the following:

1. A diesel plant consisting of three 6.9 MW diesel units, providing steam through waste heat boilers and auxiliary boilers,

2. A 15 MW rated, single automatic extraction steam turbine with four 100,00 lb/hr boilers supplying electrical and steam requirements, and

3. A 19 MW gas turbine with a supplementally fuel fired boiler. These plants are compared on the basis of their annualized cost of operation relative to the current system. The final results are intended to reflect the relative attractiveness of the design rather than the absolute economic savings which could be realized in an optimized design.

## 2. Load Model, Load Growth, and Rate Proposals

### 2.1. Load Model Description

A steam and electrical load model has been developed based on the Institute's energy consumption patterns in 1976. The model consists of 23 characteristic data sets relating temperature and time-of-day to energy consumption [1,2]. Daily steam demand and adjusted average daily dry bulb (DB) temperature\* for weekdays correlates well as is seen in Fig. 1.

The polynomial regression fitted to these data is given in Fig.

2. The correlation of weekend data is also very good and is shown in Ref. 2.

Weekday electrical consumption as a function of adjusted average daily dry bulb (DB) temperature is shown in Fig. 3. Since these data show such a low degree of correlation, the daily electrical demand was matched with an adjusted average

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\*Temperatures are adjusted by the wind chill factor.

Fig. 1 MIT Steam Load-Temperature Correlation — Weekdays

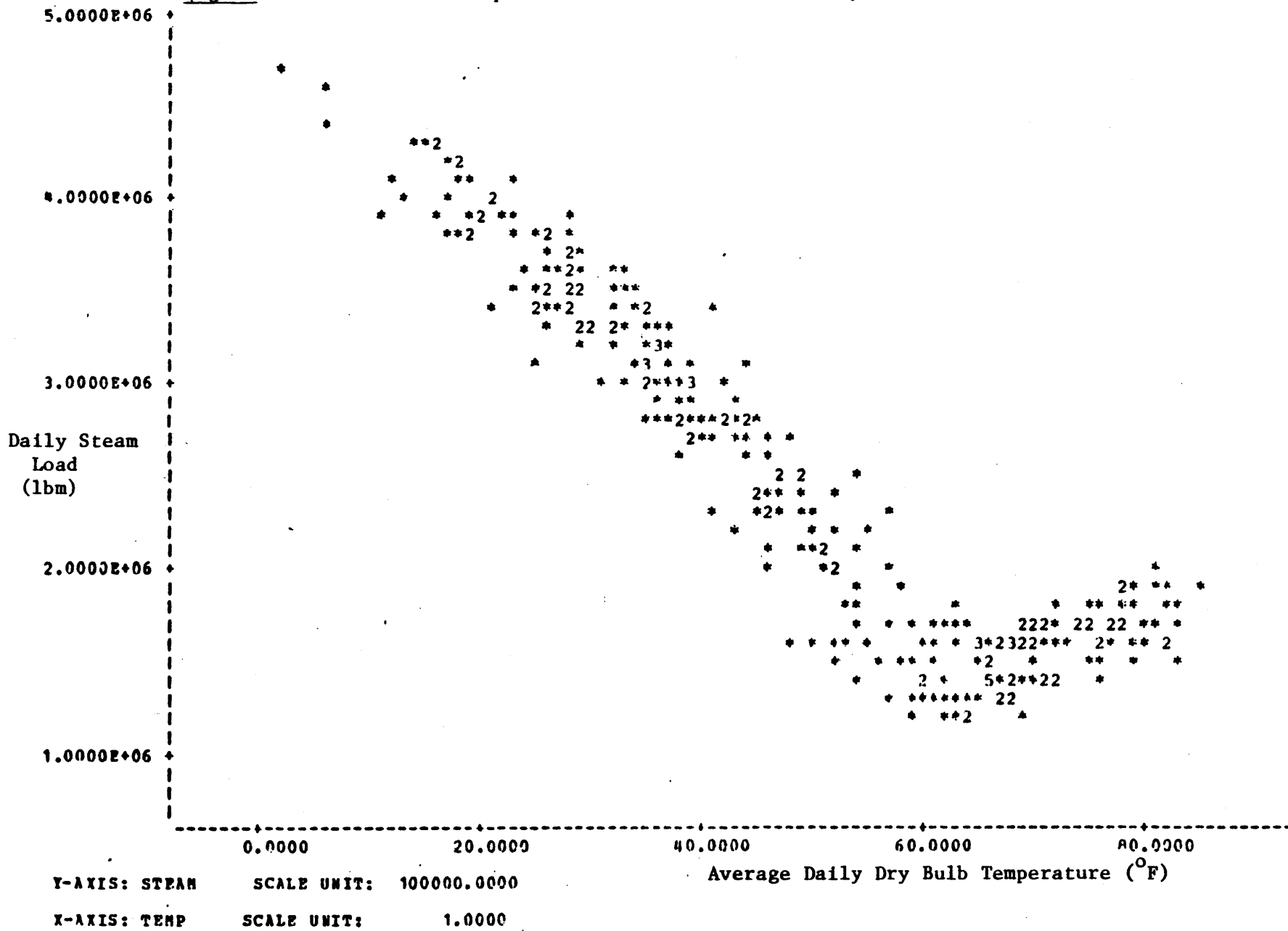


Fig. 2 MIT Steam Load-Temperature Polynomial Fit — Weekdays

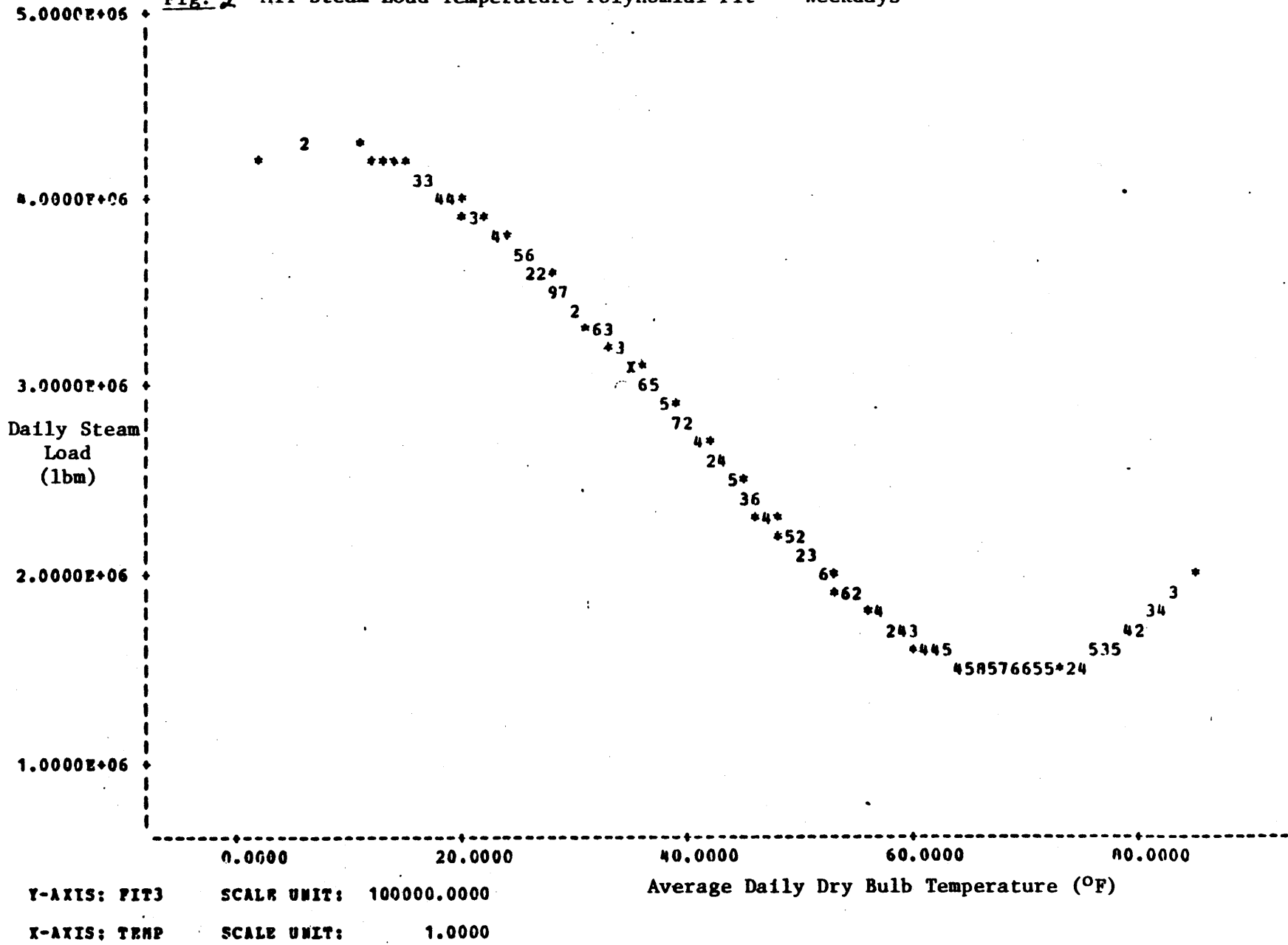
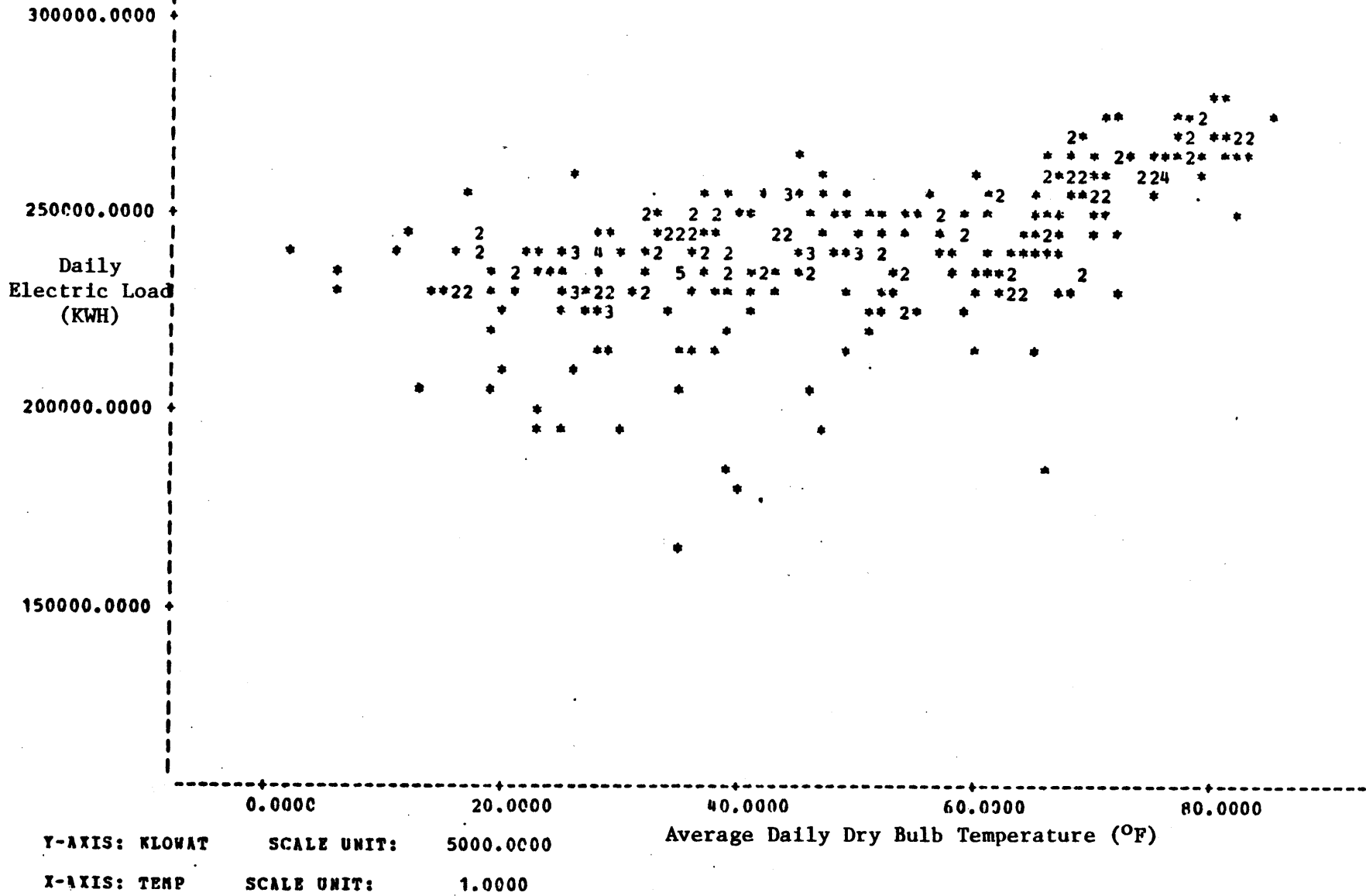




Fig. 3 MIT Electric Load-Temperature Correlation — Weekdays



daily dry bulb temperature according to the probability of a given electrical load occurring at a given temperature. That is, the daily electrical load was determined from the adjusted daily average dry bulb temperature via a table "look up" procedure using the data of Fig. 3. This is done rather than using a polynomial data regression. The same procedure was used for weekend data.

Once the daily steam and electric loads were determined, 24-hour load profiles were used to calculate the hourly loads. Nine data sets (one for weekdays and one for weekends in each season plus an extreme situation occurring in the late winter/early spring months) were used to characterize hourly steam loads [2]. A sample data set is shown in Fig. 4. Electrical load profiles for weekdays are contained in five data sets clarified according to two criteria, average daily dry bulb temperature and the time of peak load occurrence. Three data sets were used to clarify weekend electric loads according to time and magnitude of peak load occurrence. An example of an electrical load profile is given in Fig. 5. Once the daily electrical and steam loads are determined from the average daily dry bulb temperature and the 24-hour load profiles are determined for each type of day and season, it remains necessary to construct a model year for annual energy demand simulation. In doing this it is necessary to select representative days in the different seasons, and to calculate the corresponding energy demand schedules on these days. The annual energy consumption estimation is obtained by interpolating between the

Fig. 4

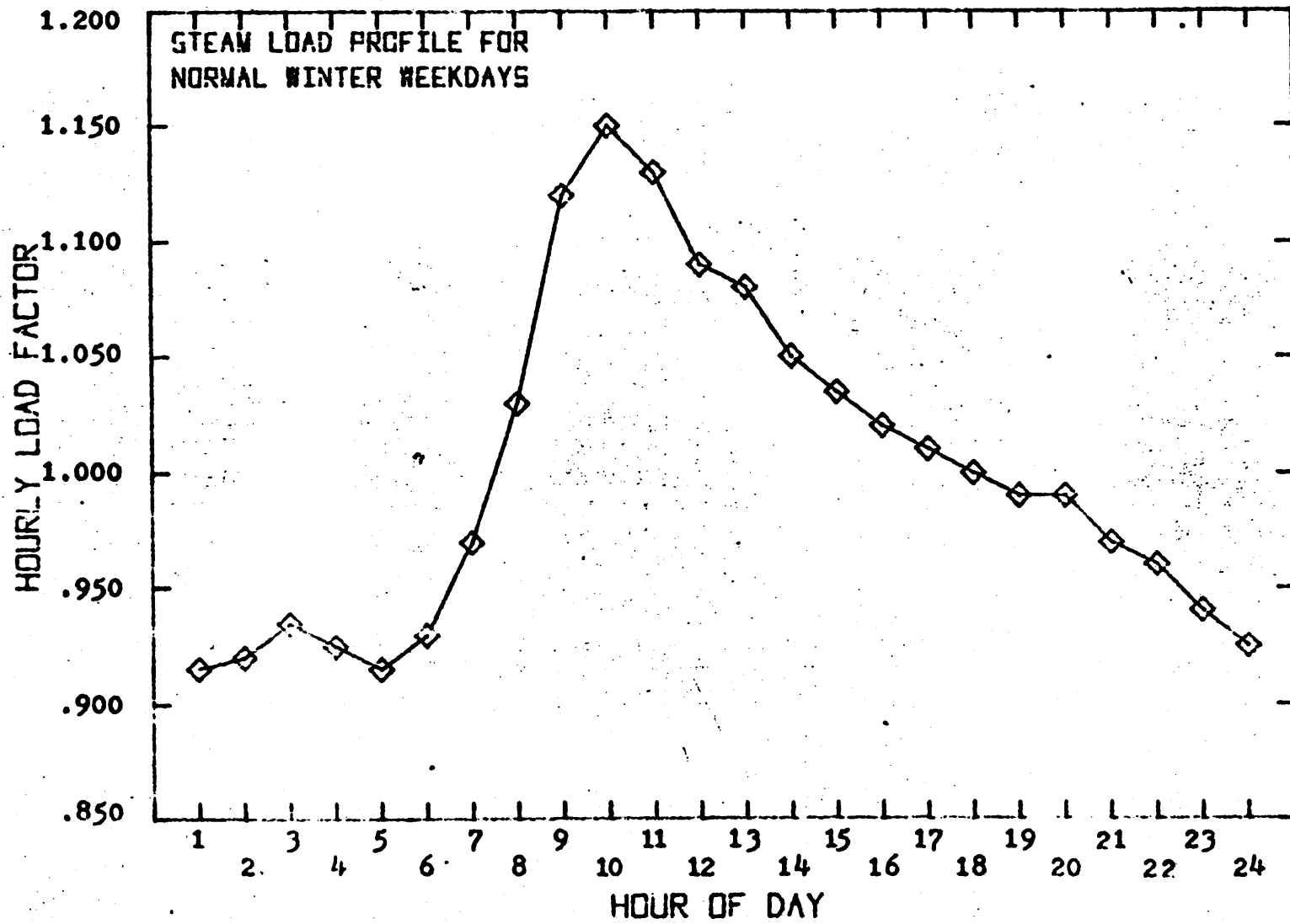
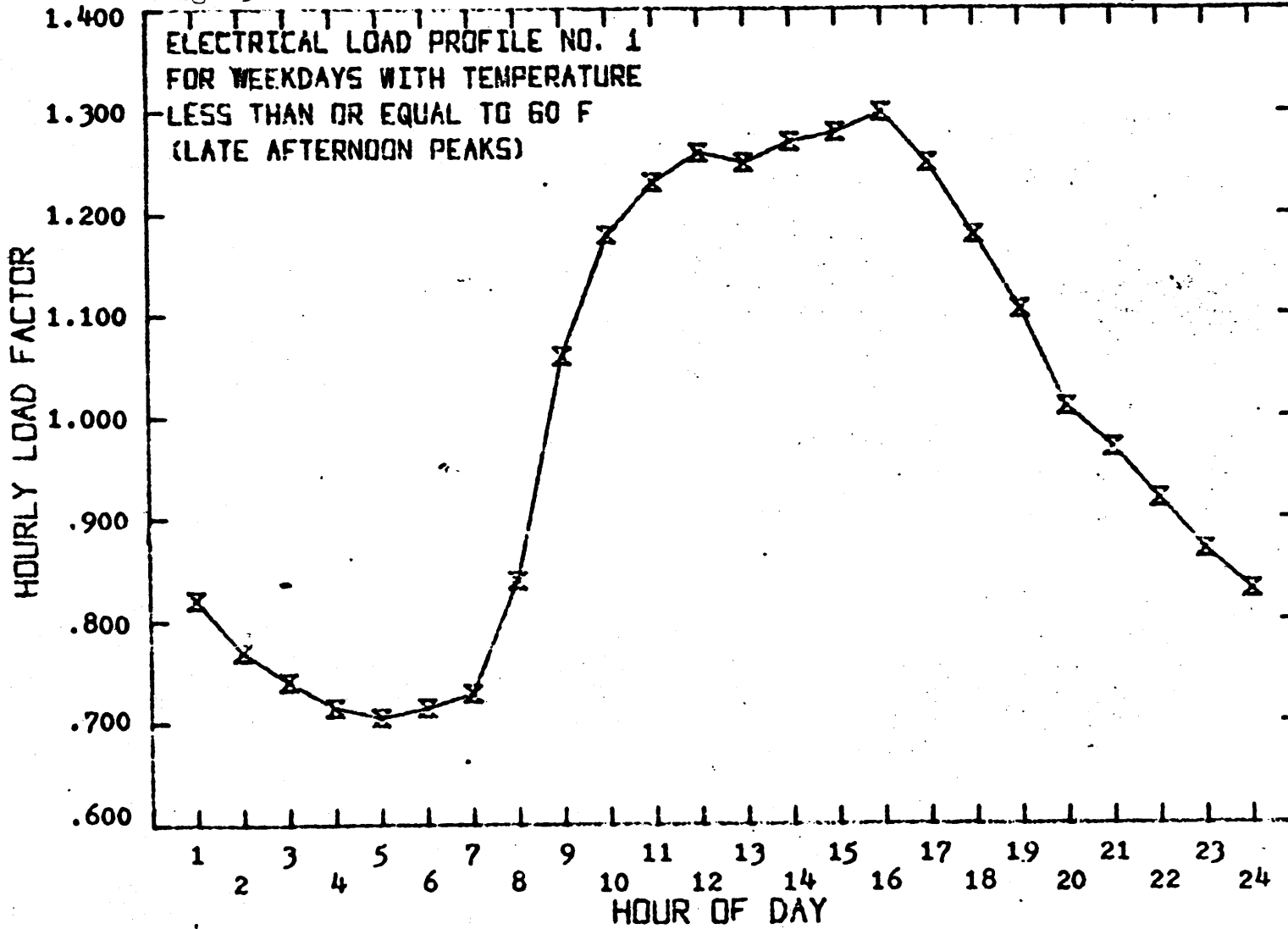


Fig. 5



representative days and integrating the resulting energy demand schedules through the year.

A decision was made to construct the model year so as to typify an average year in Boston. The average daily temperatures in Boston for each day in the past ten years were obtained from the Logan Airport Weather Station data charts. The annual frequency of occurrence of each integer average daily temperature value was tabulated for a ten-year period, and the average value was normalized to a one-year period. The temperatures were grouped into thirty-day months in a manner such that the average temperature in these fabricated months would closely approximate the actual average monthly temperatures observed over a thirty-year duration. The results of this calculation are summarized in Table 1 along with a comparison of the data for 1976.

The load model was validated by requiring the model to calculate the Institute's fuel consumption for each month of 1976. The accuracy of the model is determined by comparing the predicted fuel consumption figures against those actually recorded in 1976. The resulting errors appear in the column labeled "% error" in Table 2. As is evident, during the summer and winter months, the accuracy is very high, but during the transition seasons of spring and fall, the predictions are far from the actual consumption figures. The reason for this is thought to be the method by which the physical plant meets the Institute's energy demands. In the spring and fall, air conditioning and heating seasons overlap and the same

Table 1. MONTHLY AVERAGE TEMPERATURES IN THE MODEL YEAR

Month	Model Yr. Avg Temp.	30 Yr. Avg. Temp.	(Model Yr. Temp. minus 30 Yr. Avg. Temp.) $\Delta T$	1976 Monthly Avg. Temp.	(Model Yr. Temp. minus 1976 Avg. Temp.) $\Delta T$
January	26.7	29.2	-2.5	26.1	.6
February	28.0	30.4	-2.4	37.3	-9.3
March	35.7	38.1	-2.4	41.2	-5.5
April	48.6	48.6	--	55.1	-6.5
May	58.6	58.6	--	60.2	-1.6
June	71.1	68.0	3.1	73.4	-2.3
July	76.5	73.3	3.2	72.9	3.6
August	74.4	71.3	3.1	72.0	2.4
September	66.4	64.5	1.9	64.9	1.5
October	55.4	55.4	--	52.3	3.1
November	42.8	45.2	-2.4	41.9	.9
December	30.6	33.0	-2.4	29.0	1.6
Year	51.2	51.3	0.1	52.2	-1.0

Table 2. OIL CONSUMPTION CHART\* (Model Year and 1976)

Month	Model Year			1976		
	Avg. Temp. (°F)	(30 Yr. Avg.)	Oil Consumption (gal.)	Avg. Temp. (°F)	Oil Consumption (gal.)	% Error
January (1)	26.7	(29.2)	891,598	26.1	901,360	--
February (2)	28.0	(30.4)	872,449	37.3	732,386	-1.6
March (3)	35.7	(38.1)	759,530	41.2	691,345	+3.3
April (4)	48.6	(48.6)	553,677	55.1	497,689	+4.1
May (5)	58.6	(58.6)	426,161	60.2	416,580	+8.9
June (6)	71.1	(68.0)	367,660	73.4	408,051	--
July (7)	76.5	(73.3)	412,298	72.9	390,651	--
August (8)	74.4	(71.3)	394,201	72.0	388,201	-7.0
September (9)	66.4	(64.5)	378,679	64.9	380,819	+18.3
October (10)	55.4	(55.4)	461,158	52.3	512,139	--
November (11)	42.8	(45.2)	638,586	41.9	672,414	--
December (12)	30.6	(33.0)	833,459	29.0	873,331	--

\* Natural gas consumption has been converted to oil consumption on a 'per pound of steam produced' basis

degree of comfort can be achieved by running both systems in combination over a wide range of loads. That is, there are several combinations of steam and chilled water supply that will satisfy a given level of comfort. Hence, depending on how the system operates, fuel consumption can vary radically. This ambiguous situation being absent in summer and winter helps to account for the relatively good accuracy of level consumption prediction months.

## 2.2 Institute Load Growth Projection

The forecast of campus development to the year 2000 was provided by the MIT Planning Office and was used as a basis for future load growth prediction. Once building construction projections are made, steam and electrical loads associated with these buildings must be estimated [3]. This is not a straightforward task since buildings now on campus have peak electrical loads that vary from 10.5 KWH/ft<sup>2</sup> to 54.0 KWH/ft<sup>2</sup> and steam loads that vary from 97 lbm/ft<sup>2</sup> to 303 lbm/ft<sup>2</sup>. The greater values reflect the newer more energy wasteful buildings.

To solve this problem, buildings on campus are classified into six types:

- (1) classroom/faculty office
- (2) classroom/labs/workshops
- (3) administrative offices
- (4) living (dormitory/apartment)
- (5) athletic
- (6) computer/electronics

Data on steam and electrical consumption in these buildings were



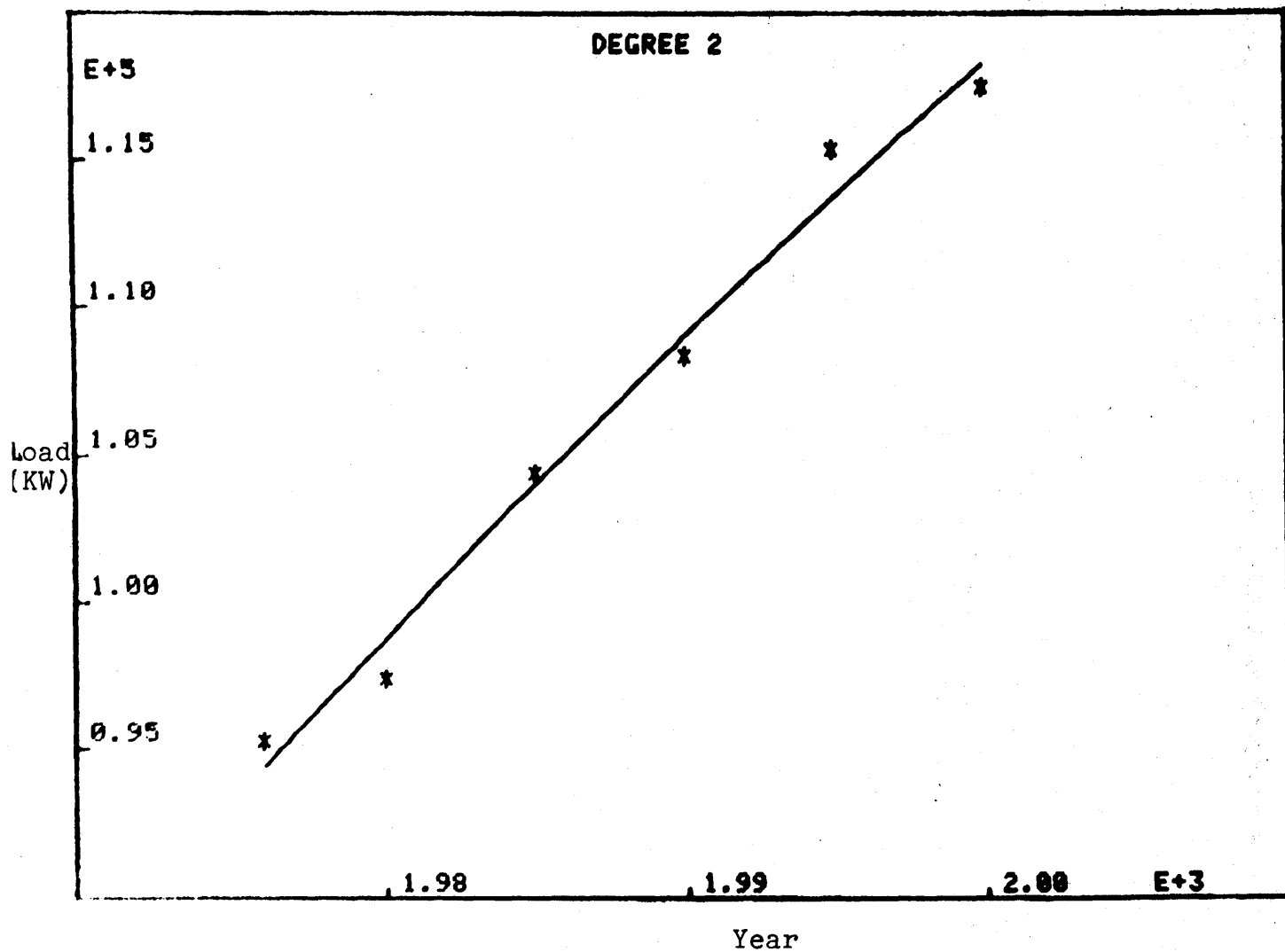
collected for the years 1972-73 and 1975-76. As a rule, the lower consumption values for steam and electricity were chosen for load growth studies in order to accommodate the Institute's plans to build more energy-conservative buildings in the future. These predicted loads were tabulated for each building type at five-year intervals from 1980 to 2000 [2].

Figures 6 and 7 give the average electrical load and the average steam load as a function of future time. The data are fitted to a second-order polynomial for predictive convenience. Thus, by the year 2000, the peak electrical load should be approximately 22300 KW and the steam load at 267,500 lb/hr. These values are used as power plant equipment design points.

### 2.3 Electric Rate Schedule Proposals

The feasibility of a total energy system depends on the savings which it can make possible with respect to purchased electric power. Such savings in turn depend upon the rate structure of the utility supplying the purchased electric power. Using the energy load model and the current electric rate structure applying to MIT, the annual cost of electricity is \$3,016,625. However, in a discussion with one of three commissioners of the Massachusetts Department of Public Utilities (DPU) [4] it became apparent that Massachusetts is evolving toward use of "time of day" or "peak" load pricing (in which a higher rate is imposed during daily and seasonal peak electricity usage periods). The DPU is currently asking electric utility companies to suggest rate structures for

Fig. 6 PROJECTED INSTITUTE AVERAGE ELECTRICAL LOAD (KW)  
FOR THE YEARS 1976-2000



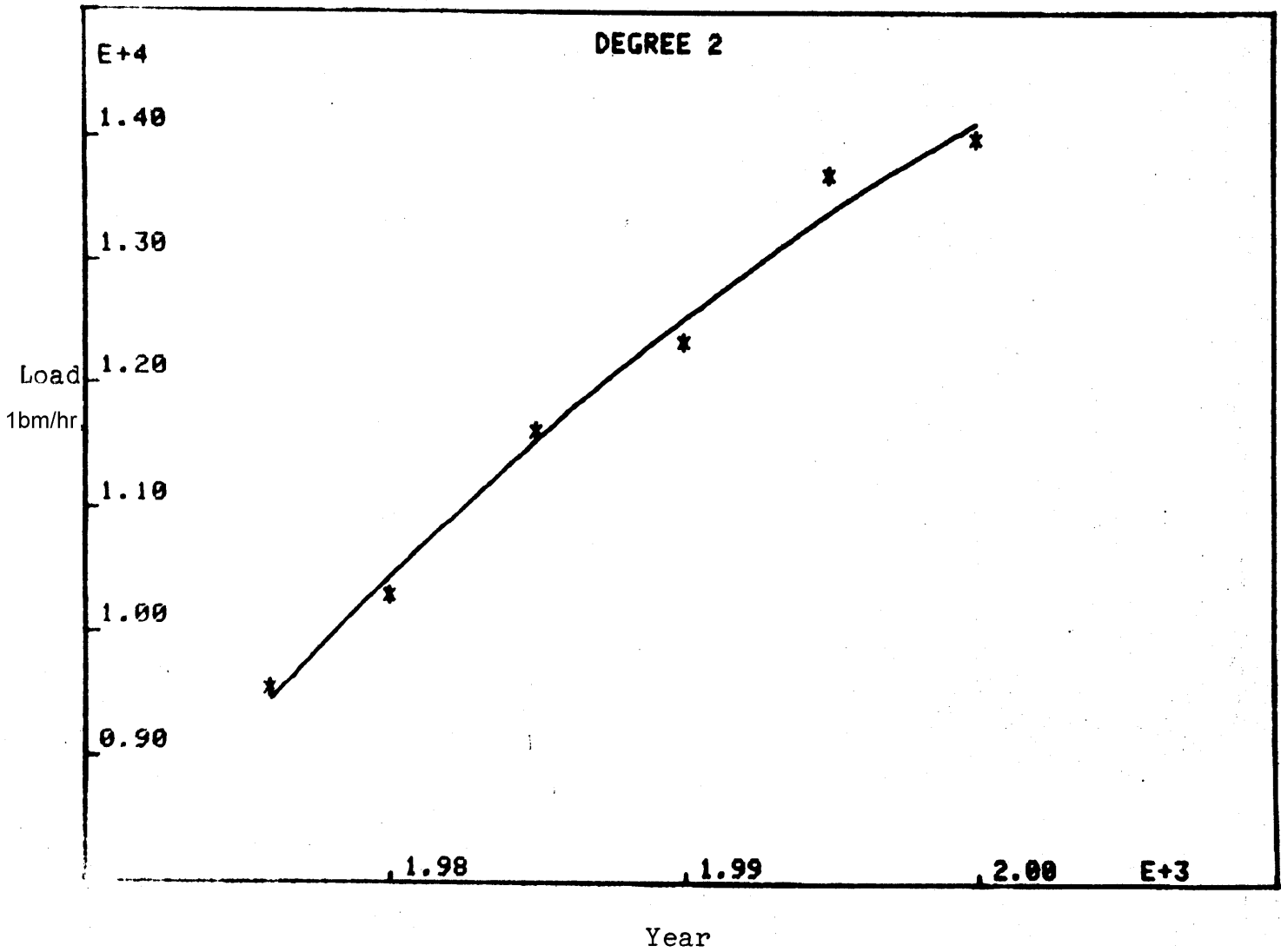
Data fit to 2nd order polynomial

$$y = -1.029 \times 10^7 + 10170.44x - 2.5092x^2 \quad (R^2 = .9887)$$

where  $y = \text{Load (KW)}$

$x = \text{Year}$

Fig. 7 PROJECTED INSTITUTE AVERAGE STEAM LOAD (lbm/hr)  
FOR THE YEARS 1976-2000



Data fit to 2nd order polynomial ( $R^2 = .9847$ )

$$y = -4.2623 \times 10^7 + 41959.1x - 10.2942x^2$$

where  $y = \text{Load (lbm/hr)}$

$x = \text{Year}$

"time of day" pricing. Two of these rates are analyzed in this work, rate H proposed by the Massachusetts Electric Company, and rate T, proposed by the Boston Edison Company. Both rates would charge more for electrical consumption during 'peak' demand hours. Table 3 gives the annual cost of purchased electricity under each of these rate schedules.

### 3. Present System and Selection of Alternatives

The current MIT power plant consists of five boilers with a steam production capacity of 300,000 lb/hr\* at 200 psi and 40°F superheat. The load model for MIT indicates that 6,989,463 gallons of #6 fuel oil is consumed in supplying the steam demand of 823,132,024 lb in 1976. Purchased electricity amounted to 82,654,960 KWH. The costs of supplying the total energy needs of the Institute with the current system is given in Table 4.

For total energy system purposes, four prime movers are available for consideration:

steam turbine  
gas turbine  
diesel system  
nuclear plant.

Due to the small scale of this project, the nuclear plant was eliminated since "economies of scale" would make the capital cost prohibitively great.

The choice of fuel is limited to that of oil due to the extensive stack-gas clean up systems that would be needed to meet current air quality standards for coal burning, and because

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\* Based on capacity with the largest boiler (100,000 lb/hr) being out of service.

Table 3. ANNUAL COST OF ELECTRICITY FOR MIT UNDER VARIOUS RATE SCHEDULES

Rate	Annual Cost (Dollars in 1977)	% Difference From Current Rate, 8
8 (Current Rate)	3,016,625	-
H (Massachusetts Electric proposed peak load pricing schedule)	3,088,703	+2.39
T (Boston Edison proposed peak load pricing schedule)	3,273,736	+8.52

Table 4. ANNUAL COSTS FOR THE PRESENT PLANT

Fuel Cost (6,989,463 gallons @ 33.71¢/gal to produce 823,137,024 lb steam)	= \$2,356,150
Purchased Electricity (82,654,960 KWH)	= <u>\$3,016,625</u>
Total Annual Cost	= \$5,372,775

of restricted supplies of natural gas. This leaves the diesel system, steam turbine, and gas turbine, all to be fueled by oil as the candidate power plant technologies.

The systems were sized to carry the peak load predicted for the year 2000. Several sizes of units are available for each prime mover. The required capacity can be supplied with many different combinations of these unit sizes. Efficiency is generally greater when several small units are employed rather than a few large units, but so are capital costs. Therefore, to simplify the equipment selection procedure, it was decided to use equipment in a unit size that could meet the capacity requirements of the plant with the fewest units. The commercial availability of the different units and their respective operating data were also considered. The solution procedure yielded the following candidate system units:

- (1) 15 MW steam turbine,
- (1) 19 MW gas turbine, and
- (3) 6.9 MW diesels.

Three diesels are used rather than a single large diesel unit due to the wide use of this size unit, and due to the wide availability of operating information. Backup capability in the form of reserve capacity or a contractual agreement with the local utility company was not considered for any system due to the paucity of available data for such an estimation.

#### 4. Method of Economic Analysis

The manner in which a plant is financed can strongly affect the outcome of a feasibility study of an engineering

project. Following the guidance of the MIT Director of Finance [5], the following economic analysis and guidelines for financing have been identified. The project is evaluated by the net present value method where future cash flows are discounted to their values in current dollars using the cost of capital, according to the relation

$$\begin{aligned} \text{NPV} &= \text{present value of future cash flows} - \text{initial cost} \\ &= \frac{CF_1}{1+k} + \frac{CF_2}{(1+k)^2} + \frac{CF_3}{(1+k)^3} + \dots + \frac{CF_n}{(1+k)^n} - I, \quad (1) \end{aligned}$$

where

$CF_1$  is cash flow in period 1

$CF_2$  is cash flow in period 2, etc.

$I$  is initial cost or outlay

$k$  is cost of capital

The initial outlay  $I$  is the plant capital cost. The cash flows consist of annual disbursements for fuel, operation and maintenance, and annual savings equal to the annual cost of the present plant. See Table 4.

The annual costs of producing electricity and steam consists of fuel and operation and maintenance costs [6]. The fuel charge is calculated on the basis of the Institute's annual energy demand, and is a variable cost each year. The steam plant, diesel plant and supplementary firing of the gas turbine

boiler are assumed to be fueled with No. 6 fuel oil at a cost of \$14.16/bbl (33.71¢/gal).

The annual operation and maintenance charge is taken to be a fixed cost equal to 15% of the power plant capital charge rate.

bond retirement and interest, and is a constant annual amount until all bonds are retired, as shown in the relationship

$$\phi = \text{capital charge rate} = A + I, \text{ where}$$

A = annual cost of bond retirement,

I = annual interest cost, and

A + I = F(A/P, i%, x), where F = par value of bonds

(A/P, i%, x) = capital recovery factor,

i% = interest rate or cost of capital, and

x = bond term

Therefore, operation and maintenance costs are  $.15\phi = .15(A+I)$ . Hence, we have the result

$$\begin{aligned} \text{NPV} &= \frac{CF_S}{(1+k)} + \frac{CF_S^2}{(1+k)^2} + \dots + \frac{CF_S^n}{(1+k)^n} \\ &+ \frac{CF_{OM}}{(1+k)} + \frac{CF_{OM}^2}{(1+k)^2} + \dots + \frac{CF_{OM}^n}{(1+k)^n} \\ &+ \frac{CF_F}{(1+k)} + \frac{CF_F^2}{(1+k)^2} + \dots + \frac{CF_F^n}{(1+k)^n} \end{aligned} \quad (2)$$

where  $CF_S$  = cash flow from savings,

$CF_{OM}$  = cash flow from operation and maintenance, and

$CF_F$  = cash flow from fuel .



The equivalent annual savings and rate of return on investment is calculated for each project as an aid in project comparison. It is important to note that all costs and savings given in this report are in 1977 dollars.

Each design has undergone a sensitivity analysis in which several key parameters affecting cost are varied to determine the sensitivity of the annual rate of return to each parameter [2]. The parameters significantly affecting economic results are the following:

- Oil Cost
- Initial Capital Investment
- Operation and Maintenance Cost
- Plant Life
- Bond Interest Rate
- MIT Interest Rate
- Revenue from Rate Schedules
- Inflation Rate
- Load Growth
- Method of Depreciation
- Cost of Backup

A discussion of the various plant alternatives follows.

##### 5. Diesel Plant Evaluation

Three 6.9 MW Colt-Pielstick diesels with waste heat boilers in addition to the boilers of the present plant would be used to supply the Institute's total energy needs through the year 2000. The maximum electrical output of this plant is 20.7 MW, but operation for short periods of time at 110% of the nominal capacity is possible. This would supply 22.8 MW, which exceeds the 22.3 MW peak demand expected in the year 2000. The maximum steam production from the waste heat boilers is 37,500 lb/hr

which would be supplemented by the existing plants' newer boilers in order to supply the anticipated steam demand through the year 2000. The analysis of the diesel plant operation is based on the following assumptions:

Use of three diesel units, nominal capacity rating = 6.9 MW each, operation at continuous shaft speed, specific fuel cost = .0659 gal/kw-hr at 100% load, fuel type = #6 fuel oil (heating value =  $18,500 \frac{\text{BTU}}{\text{lb}}$ ), maximum capacity = 110% of nominal rated capacity, and plant life = 20 years.

### 5.1 Capital Cost Analysis

Estimated plant capital costs are itemized as follows [3]:

Three 7 MW units with waste heat boilers and auxiliary equipment	\$5,222,000
Installation costs	200,000
Piping for fuel oil and cooling water	270,000
Building (11200 ft <sup>2</sup> @ \$25/ft <sup>2</sup> )	280,000
Electrical switchboard & distribution system	465,000
Fuel oil tanks (917,000 gal cap.)	<u>465,000</u>
	<u>\$6,902,000 .</u>

The capital charge rate and operation and maintenance costs are calculated as outlined in Section 4, and the results are presented in Table 5.

### 5.2 Fuel Costs

Annual operation of the diesel units supplying 100% of the Institute's electrical demands (according to the load model

Table 5. NET PRESENT VALUE OF A DIESEL SYSTEM\*

Initial investment	-\$ 6,902,000
1st replacement cost \$6,902,000 (P/F, 6%, 20)	-\$ 2,152,043
2nd replacement cost \$6,902,000 (P/F, 6%, 40)	-\$ 670,131
3rd replacement cost \$6,902,000 (P/F, 6%, 60)	-\$ 290,131
Annual expenses (operation & maintenance + fuel) \$3,812,232 (P/A, 6%, 60)	-\$61,611,006
Annual savings (fuel + purchased electricity) \$5,372,775 (P/A, 6%, 60)	\$86,831,566
Net Present Value = \$15,286,512	
Equivalent Annual Worth = \$958,962	
Equivalent Rate of Return on Investment = 13.9%	
Capital Charge Rate=A+I=\$6,902,000 (A/P, 6%, 20)=\$601,854	

\* 20 year life evaluated on a 60 year basis for comparison with systems of differing lives, interest rate = 6%.

developed in this work) requires 5,319,000 gallons of No. 6 fuel oil. Additional fuel needed for the supplementary boilers amounts to 5,722,000 gallons of No. 6 fuel oil, for a total of 11,041,097 gallons. At a cost of \$14.16/bbl or 33.71¢/gal this amounts to a total fuel charge of \$3,721,954, included in Table 5.

### 5.3 Plant Analysis

The data of Table 5 indicates that installation of a total energy system consisting of the diesel units described would result in an annual savings of \$958,962 over the present plant operation costs in 1978. This yields an annual rate of return of 13.9% on the project.

### 6. Steam Plant Evaluation

The steam plant analyzed consists of four (4) 100,000 lbm/hr boilers generating steam at 800 psig and 875°F, and one (1) 15 MW rated General Electric single automatic extraction turbine with steam extraction at 200 psig. The maximum electrical output of 25.5 MW will satisfy the twenty-year projected electrical demand peak of 22.3 MW, while the 7 MW current base load at the Institute is within the range of the unit. The steam system operation is based on the following assumptions:

Use of a 100,000 lb/hr boiler @ 800 psig, 875°F,  
steam extraction @ 200 psig, 428°F,

Use of a 15 MW rated G.E. Turbine (3.0" Hg. outlet  
backpressure

maximum throttle flow = 445,600 lb/hr

minimum throttle flow = 13,000 lb/hr

maximum generator output = 25.5 MW),

Operation at continuous shaft speed and

Fuel type = #6 fuel oil (heating value = 18,500 BTU/lb).

The maximum steam load expected to the year 2000 is 267,500 lb/hr with a peak demand of approximately 300,000 lb/hr occurring at the end of the life of the plant (in the year 2010). Four 100,000 lb/hr boilers are assumed to be installed under the rationale that no more than three boilers would be operating at any given time allowing the fourth boiler to be down for maintenance or reserved for emergency use. This redundancy will add protection to the Institute against a loss of power due to a malfunctioning boiler. Boiler fuel consumption can be related to steam flow from the following relationship

$$\dot{m}_f = \left( \frac{\dot{m}_s \Delta h_{fw}}{\eta_B h_{HV}} \right) \left( \frac{1}{7.55} \right) \quad (3)$$

where

$\dot{m}_f$  = fuel flow rate (lb/hr),

$\dot{m}_s$  = steam flow rate (lb/hr),

$\Delta h_{fw}$  = change in enthalpy of feedwater across boiler  
( 1058 BTU/lb),

$h_{HV}$  = heating value of No. 6 fuel oil (18500  
BTU/lb), and

$\eta_B$  = boiler efficiency.

Equation 3 can be reduced to the result

$$\dot{m}_f = \left( \frac{\dot{m}_s}{\eta_B} \right) 0.00927 \text{ lb/hr.}$$

Since  $\dot{m}_g$  is given as the boiler steam demand, the fuel consumption is computed using Eq. 3. These calculations were performed on an hourly basis for each day of the year in order to arrive at an estimate of annual fuel consumption.

### 6.1 Capital Cost Analysis

Estimated plant capital costs are itemized as follows

[3]:

One 15 MW-rated steam turbine	\$2,200,000
Installation costs	990,000
Condenser, cooling tower and piping system	1,186,356
Four 100,000 lb/hr boilers (@ \$1,250,000 each)	5,000,000
Pumps	83,300
Heat exchangers	69,500
Piping & valving	1,300,000
Electrical switchboard & distribution system	375,000
Building (11,200 ft <sup>2</sup> @\$25/ft <sup>2</sup> )	280,000
Miscellaneous expenses	1,269,000
	<u>\$12,753,156.</u>

The capital charge rate and operation and maintenance costs are calculated as outlined in Section 4, and the results are presented in Table 6.

### 6.2 Fuel Costs

Annual operation of the steam system to supply total electrical and steam loads requires 13,383,000 gallons of No. 6 fuel oil, costing \$4,511,000 as shown in Table 6.

### 6.3 Plant Analysis

The data of Table 6 indicate that installation of the steam system described would result in an estimated annual operating cost \$203,804 greater than that of the present plant in 1977. Although the capital costs are almost double those of the diesel unit, it actually is the high fuel cost

Table 6. NET PRESENT VALUE OF A STEAM TURBINE SYSTEM\*

Initial investment	-	\$12,753,156
1st, replacement \$12,753,156 (P/F, 6%, 30)	-	\$ 2,220,324
2nd replacement \$12,753,156 (P/F, 6%, 60)	-	\$ 386,421
Annual expenses (operation & maintenance + fuel) \$4,650,212 (P/A, 6%, 60)	-	\$75,153,936
Annual savings (fuel + purchased electricity) \$5,372,775 (P/A, 6%, 60)		\$86,831,566
Net Present Value = -\$3,862,271		
Annual Savings = -\$230,804		
Equivalent Rate of Return on Investment = -1.6%		
Capital Charge Rate=A+I=\$12,753,156 (A/P,6%,30)=\$925,879		

\* 30 year life evaluated on a 60 year basis for comparison with systems of differing lives, interest rate = 6%

that places the steam turbine at such a disadvantage with respect to the alternatives. Since fuel costs account for more than 80% of the total annual costs for all systems, to first-order it is always fuel consumption that will determine the relative feasibility of use of a candidate technology.

## 7. Gas Turbine Plant Evaluation

A single 19 MW gas turbine with a 300,000 lb/hr supplementary-fired exhaust heat boiler which is able to provide total electrical and steam loads at MIT is also analyzed. The gas turbine plant has an expected life of 20 years at which time the electrical load peaks would just exceed the maximum generator output. It should be noted that this turbine can run at 110% of nominal capacity (or 21 MW) for one or two hours at a time. This brings it even closer to supplying the year 2000 peak load. The slightly-undersized 19 MW gas turbine was selected for study due to the availability of performance data for this size turbine, and because it matched well the estimated long-term capacity requirements. Assumptions upon which calculations are based are the following:

The compressor inlet temperature is constant at 80°F,

A continuous synchronous shaft speed is used at 100% of rated speed),

The boiler exhaust temperature is constant (at 340°F),

The stack gas enthalpy = 85 BTU/lbm,

The 10" pressure drop through the boiler = 10" H<sub>2</sub>O

Steam system blowdown losses = 3% of the peak flow rate,



Exhaust heat loss = 3% of total heat consumption,

Specific fuel consumption rating = .116 gal/KWH

Rated electrical capacity = 19000 KW,

Fuel type = No. 2 distillate fuel oil for the gas turbine, and No. 6 fuel oil for supplementary-firing of boiler, and

Assumed plant life = 20 yrs.

### 7.1 Capital Cost Analysis

Plant capital costs are itemized as follows [3]:

One 19 MW gas turbine and waste heat boiler (300,000 lb/hr)	\$2,565,000
Installation costs	200,000
Piping	180,000
Building (11,200 ft <sup>2</sup> @ \$25/ft <sup>2</sup> )	280,000
Electrical switchboard & distribution system	465,000
Fuel oil tanks	<u>465,000</u>
	<u>\$4,155,000</u> .

### 7.2 Fuel Costs

Annual operation of the gas turbine unit to supply the year 2000 total MIT electrical energy demand in the year 2000 requires 11,680,000 gallons of No. 2 distillate fuel oil. Another 2,906,000 gallons of No. 6 fuel oil are required to supplement the steam production. The resulting fuel costs are \$4,904,000 for No. 2 oil and \$979,500 for the No. 6 oil, giving a total of \$5,156,000 as shown in Table 7.

### 7.3 Plant Analysis

The data of Table 7 show that a total energy system using the gas turbine plant described previously would cost the Institute

Table 7. NET PRESENT VALUE OF A GAS TURBINE SYSTEM\*

Initial investment	-\$ 4,155,000
1st replacement \$4,155,000 (P/F, 6%, 20)	-\$ 1,295,529
2nd replacement \$4,155,000 (P/F, 6%, 40)	-\$ 403,866
3rd replacement \$4,155,000 (P/F, 6%, 60)	-\$ 125,892
Annual costs (Operation and Main- tenance + fuel) \$5,699,351 (P/A, 6%, 60)	-\$92,109,491
Annual savings (fuel + electricity)	\$86,831,566
Net Present Value = -\$11,258,217	
Annual Savings = -\$688,949	
Rate of Return on Investment = -16.6%	

\* 20 year life evaluated on a 60 year base for comparison with systems of differing lives, interest rate = 6%

\$688,949/year more than the current system. The impact of fuel costs can be seen most dramatically in this case. Although the plant capital costs are less than 1/3 those of the steam plant and are only 60% those of the diesel plant, it is seen that steam plant fuel costs amount for 90% of the total annual energy production costs. The fuel cost component is so large for this scheme that net losses are estimated to result.

#### 8. Factors not Included in this Preliminary Analysis

Several significant factors have not been included in this study due to a lack of available information on the subjects. These factors will be discussed briefly.

##### Back-up from Cambridge Electric

Back-up capacity from Cambridge Electric will be necessary for any power plant design which itself does not provide redundancy for maintenance and emergency service. The back-up charge would be determined from MIT's monthly demand schedule. Since the peak demand is presently in the 15,000 KW range, a rough estimate of the charge for back-up service can be obtained from Cambridge Electric's minimum charge of \$2.25/KW for breakdown or auxiliary service. This would result in a monthly charge of \$33,750 or an annual charge of \$405,000 if peak-demand back-up service were desired. This cost would be enough to render all designs impractical except for that of the diesel system. In reality, a more modest level of backup service—possibly for both thermal and electrical systems—would be required at correspondingly lower costs.

### Architect Engineer's Study

An Architect/Engineer must be employed to design the actual plant once a candidate technology is selected. The cost of such a study could be significant compared to the annual savings estimated in this study. Hence, this factor of consultant costs will decrease the net rate of return for any total energy scheme and must be included in the final economic study.

### Additional Capital Investment in the Current Plant

Since the study spans a 20 year period, anticipated modifications to the present plant should be taken into account. Current plans are to install a new 100,000 lb/hr steam boiler within the next few years if the current plant were to remain in service. This should be accounted for as a capital credit for the ability to avoid such an investment in the alternative designs. However, such an accounting procedure can best be accomplished by an architect engineer.

### Coal

The use of coal for steam production and as a diesel fuel is a possible option that can lead to a reduction in fuel cost and improve the economic outlook of the alternatives. However, the cost of coal transportation to New England along with the difficulty in obtaining a supply commitment are serious disadvantages. Further, the cost of a stack gas clean-up system to reduce air pollution will be a significant factor.

### Salvage Value

No credit has been taken in the depreciation calculations

for the salvage value of the proposed plant systems. Further, no salvage value credit has been taken for the present boilers which would not be used in the steam and gas turbine plants. Thus, the largest salvage savings would be realized in these configuration since they require the most new equipment. However, the magnitude of the salvage value will probably not be able to overcome the large deficit in the steam plant.

#### National Magnet Laboratory Electrical Load

The non-uniform electric load at the Magnet Lab has not been considered in this analysis. It is possible that with the remainder of MIT withdrawing from Cambridge Electric as a steady customer, a higher rate may be imposed upon this load.

#### Inflation and Escalation

The effects of inflation and escalation have not been accounted for in this study. A complete and thorough study will determine the rate of return and absolute dollar savings for each year of plant operation accounting for inflation and escalation in labor, materials and fuel. Rather, this study should be viewed as an analysis in constant-dollar terms of the technical alternatives discussed previously, with no predictions being made of future trends.

#### 9. Analysis and Recommendations

On the basis of the preceeding economic analysis of 1976 operation of the total energy system options for MIT, the following observations can be made. Fuel costs heavily dominate all estimates of annual system energy production costs. Basically, this factor alone controls the feasibility of a

particular design. This point is shown clearly in Fig. 8. The diesel system consumes substantially less fuel than do the other options. Combined with low capital costs, it is the most attractive system among those considered. The steam plant consumes an intermediate amount of fuel; however, due to its large capital costs, this option suffers great losses. The gas turbine design is seen to be the most fuel-intensive. Although the gas turbine capital cost is the smallest of all of the options, such savings are too small to compensate for the large annual fuel charge. In fact, the cost of fuel alone more than erases the total yearly revenues (savings) from purchased electricity and boiler fuel.

The heavy dependence of system economies on fuel consumption can be related to the yearly averaged operating efficiencies for each plant, Table 8. It is seen that there exists an inverse relation between system efficiency and fuel consumption. The efficiency of the current plant is very high since it produces only steam and purchases electricity. Because of the strong dependence of system economics upon fuel costs it is seen that the prime design objective in any new system should be minimization of fuel consumption.

In reviewing the systems chosen for this analysis, areas are identified as requiring further work. First, a study of multiple-unit vs single-unit operation should be made. The former option offers opportunities for increasing efficiency and reduces the need for purchasing back-up capability.

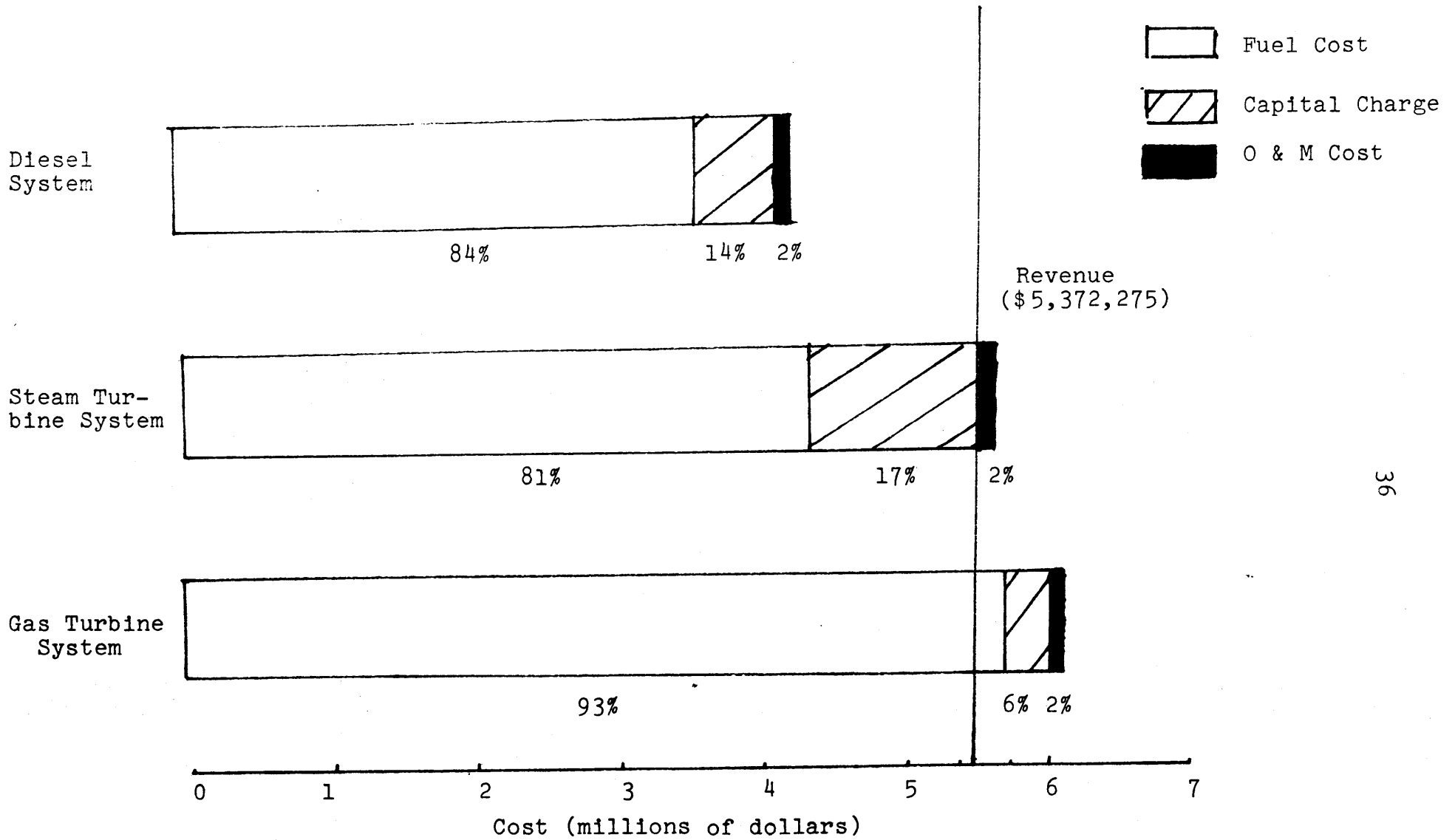


Figure 8. ANNUAL COST COMPONENTS FOR ALTERNATIVE TOTAL ENERGY SYSTEMS

Table 8. YEARLY AVERAGED PLANT OPERATING EFFICIENCIES\*

Present Plant**	89%
Diesel System	75%
Steam Turbine	62%
Gas Turbine System	58%

$$* \text{ Efficiency} = 100 \times \frac{\text{Electrical Energy Load (BTU)} + \text{Steam Energy Load (BTU)}}{\text{Combustion Energy of Fuel Consumed (BTU)}}$$

\*\* Steam production only



Multiple units would also allow the deferral of capital investment expenses since units could be purchased as needed as demand grows. This will also eliminate much of the uncertainty associated with building a large single-unit plant based on long range load growth forecasting.

A sensitivity analysis performed [2] performed earlier indicates that the rate of return associated with a particular option is most sensitive to oil cost, inflation and rate schedule. However, although the magnitudes of the savings or losses may change with these parameters, the order of attractiveness of the three systems remain unchanged.

Finally, the precise values of the results are highly dependent on the method of economic analysis. That is, an institution or firm that finances projects in a manner different from MIT may obtain drastically differing results. The results will differ in the magnitudes of the capital charges, which--if large enough--could conceivably result in a different ordering of the alternatives (though this outcome is not considered to be likely). Thus, there are several important factors which have been neglected in this analysis which must be taken into account before a complete assessment of the set of alternative total energy system options will be available.

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