Contract No. 895-85-01-001

CIVIL ENGINEERING LABORATORY COGENERATION PROGRAM - CELCAP USER DOCUMENTATION

An Investigation Conducted by
TWO D ENGINEERING, INC.
P.O. Box 2837
Oxnard, CA 93034

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**CIVIL ENGINEERING LABORATORY COGENERATION ANALYSIS PROGRAM - CELCAP USER DOCUMENTATION**

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**Naval Construction Battallion Center**
**Port Hueneme, California 93061**

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**111**

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**Cogeneration, heat recovery, total energy systems, energy conservation**

**This report documents input requirements for the CEL Cogeneration Analysis Program (CELCAP) and includes reference material from which much of the input data can be drawn. A sample of each card is provided. No program listing or output listing is included, however. CELCAP analyzes the performance and economics of cogeneration systems utilizing combustion turbines, diesels, or steam turbines. The effects of engine combinations, engine size, control mode, use of peaking engines, utility rate structure, sale of power to the utility grid, fuel type, fuel price, and future cost escalation can be determined by varying the input.**
20. Continued.

The program computes design point engine performance, compares thermal and electrical loads against engine output, adjusts engine output according to the assumed control mode, and calculates the resulting instantaneous and life cycle costs of operation.

The program is written in FORTRAN IV for execution on CDC systems with 60 bit words.
INTRODUCTION

CELCAP is a computer program written at CEL for the analysis and comparison of cogeneration system alternatives at Navy activities. The cogeneration system may stand alone, or it may be fully integrated with the utility company grid. The concept of a fully integrated cogeneration system is depicted in Figure 1 (page iv).

Features of the program are:

a. Analyzes steam turbine (single extraction or back pressure), combustion turbine, and diesel systems;

b. Handles any mixture of five (5) or less engines;

c. Compares operation of system assuming three different control modes (modulation to follow thermal load, modulation to follow electrical load, and constant operation at full load);

d. Can analyze effect of installing peaking engines as well as cogeneration units;

e. Accurately predicts off-design performance of engines;

f. Predicts cost of purchased electrical power and revenues from sale of power to grid with rate structure algorithm (algorithm can be readily modified for different rate structures);

g. Input data includes typical steam and electrical load profiles for work days and non-work days of each month, engine design point data, fuel prices, rate data for purchased electricity, and assumed escalation rates for fuel, power, and O&M;

h. Output data includes comparisons of the system's steam and electrical outputs vs. loads (plots and tabulation), monthly and first year breakdown of costs, and annual cost projections throughout the life cycle. Much of the information needed for completion of MILCON request form 1391 is included.

This is the "User's Manual" for the CELCAP program. The manual includes a great deal of the input information required by users at the EFD's, or will specify the source of information for the user. For example, design point data for a number of typical engines will be included in such a way that the input for most engines can be accurately inferred. Basically, the user will be responsible only for providing site specific information on the thermal and electrical load patterns and the electrical utility rate structures.
CELCAP is intended to be a tool for conducting "first cut", or "fatal flow" analysis of congestion system options; it is not intended as a design tool. Because of the flexibility, however, it allows rapid consideration of a large number of alternatives and evaluation of many parameters. Experience gained by CEL in evaluating cogeneration options at several Navy activities has resulted in the conclusion that preliminary comparisons of alternatives can be conducted at very reasonable costs with CELCAP, and conclusions can be drawn regarding the alternative(s) to be considered for more detailed analysis and design. A general description of the organization of the CELCAP program follows.

CELC ANALYSIS PROGRAM FOR COGENERATION SYSTEMS

SECTION 1. Determine "Limiting" System Performance

Input: Engine mix for analysis.
Design parameters of each system.
Site atmospheric information.

Output: Limiting electrical and steam production and fuel consumption.

Capability: Combustion turbines with exhaust boilers.
Diesels with exhaust boilers.
Steam extraction turbines, back-pressure turbines.
Peaking or cogeneration units.

SECTION 2. Determine Steam and Electrical Loads

This algorithm is site-specific. For LBNSY, algorithm considers impact of industrial loads, losses, ships, and weather.

SECTION 3. Compare Loads and System Performance

Input: Mode desired.
Identify peaking unit operation periods.

Output: Electrical and steam production and fuel consumption of each engine in response to loads and control mode.
Purchase or sale of electrical power.
Make-up steam from fixed boiler.
Amount of excess steam produced.

Capability: Control modes: Full throttle.
Modulation with electrical load.
Modulation with steam load.
SECTION 4. Calculate Annual Costs

Input: Fuel costs for each type system. 
       O&M costs for each type system.

Output: Annual fuel costs: Combustion turbines. 
       Diesels. 
       Steam turbine boilers. 
       Fired "make-up" boilers.

Annual O&M costs: Combustion turbines. 
       Diesels. 
       Steam turbines and boilers. 
       Fired "make-up" boilers

Purchased electricity costs. 
Revenue from sale of electrical power.

The algorithm for cost of purchased electrical power and revenue from sale of electrical power is site-specific. Algorithm for LBNSY uses TOU-8 schedule of SCE.

SECTION 5. Calculate Life Cycle Costs (LCC)

Input: Short and long term escalation rates; fuel O&M. 
       Key years: Year of "present" worth. 
       Installation year. 
       Year of change in escalation rates. 
       End of economic life. 
       Discount rate.

Output: Future value for each output of SECTION 4. 
         Total LCC over economic life.
Integrated utility company service and cogeneration plant.
Reference material has been included throughout this publication to ease the collection of data. All input data is to be entered on cards. Valid copies of the input data cards are located on pages 81 through 111 to verify the designated format.

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THE CURRENT PRICES

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CONTROL MODES

Enter your choice in card 1, column 1.
The control modes to be considered are:
Choose 0: if the engines are run at peak electrical output.
Choose 1: if the engines follow electrical load up to their capacity.
Choose 2: if the engines follow steam load up to their capacity.
Choose 3: if all of the above control modes are to be considered.

Variable name: MDLTR
Data card sample on page 81.

REPORTS

Enter your choice in card 2, column 1.
The printout will be produced in either of 2 ways:
Choose 1: if a detailed printout is desired.
Choose 2: if only engine information, annual costs, and life cycle cost printouts are desired.

Variable name: IPRINT
Data card sample on page 81.
(TEVP) the steam has PRESSURE, KNOWN OR TEMPERATURE, ASSUMED

(HLV) the heat of evaporation has PRESSURE AND TEMPERATURE, REFER TO STEAM TABLE

(BLREF) the boiler has efficiency KNOWN OR ASSUMED

(TBLFRO) the feed water has temperature KNOWN OR ASSUMED

**THE AUXILIARY FIRED BOILER**

Refer to the steam table on page 3 for specific data.

**ENTER IN CARD 3:**

Columns: 1 thru 10: the feed water temperature, R. TBLRFD
11 thru 20: the evaporation temperature, R. TEVP
21 thru 30: the heat of evaporation, BTU/LB. HLV
31 thru 40: the boiler efficiency, decimal form. BLREF

Data card sample on page 82.
A MULLER CHART FOR STEAM

Modified and greatly reduced from Kessel and Kers's Thermodynamic Properties of Steam, published 1956 by John Wiley and Sons, Inc. Reproduced by permission of the publisher.

Copyright, 1940, by
Frank O. Ellenson, William N. Bernard
and Charles O. Mackey

Enthalpy-entropy diagram for steam.
ENTER IN CARD 4:

Column 1: the total number of gas turbines.  
Column 2: the total number of diesel engines.  
Column 3: the total number of auto extraction steam turbines.  
Column 4: the total number of back pressure steam turbines.  

Enter 0 or a combination of these four, but no more than a total of five.

Data card sample on page 83.

ENTER IN CARD 5:

Columns 1 thru 6: The decimal form of the ambient pressure at the location of this study.

NOTE: If you cannot determine the ambient pressure, use 14.7.

Variable name: PAMB

Data card sample on page 83.
To determine the maximum and minimum temperature of each month refer to the Local Climatological Data Annual Summary with Comparative Data produced by the Department of Commerce. Use the table, "Normals, Means and Extremes." A copy of this summary can be obtained from:

Climatological Analysis
National Climatic Center
Asheville, North Carolina  28801
FTS Telephone Number: 672-0319

Refer to pages 6 thru 9 for a copy of a sample summary.
Local Climatological Data
Annual Summary With Comparative Data
1978
PROVIDENCE, RHODE ISLAND

Narrative Climatological Summary

The proximity to Narragansett Bay and the Atlantic Ocean plays an important part in determining the climate for Providence and vicinity. In winter, the temperatures are modified considerably, and a good many of the major storms drop their precipitation in the form of rain, rather than snow. In summer, many days that would otherwise be uncomfortably warm are cooled by refreshing sea breezes. At other times of the year, sea fog may be advected in over land by onshore winds. In fact, most cases of dense fog are produced in this way; but the number of such days is few, averaging two or three days per month. In early fall, severe coastal storms of tropical origin sometimes bring destructive winds to this area. Even at other times of the year, it is usually coastal storms which produce the most severe kind of weather.

The temperature for the entire year averages around 50°, ranging from a low of 47° in 1917 to a high of 54° in 1949. January and February are the coldest months, with a mean temperature near 29°, while July is the hottest with a mean close to 72°. The average temperature for the first two months has ranged from as low as 17° in February of 1934 to as high as 39° in January of 1932; while the range for July has been from 68° in 1914 to 78° in 1952. August is nearly as warm as July, with an average temperature around 70°.

Pressing temperatures occur on the average about 125 days per year. They become a common daily occurrence the latter part of November, and cease to be common near the end of March. The average date for the last freeze in spring is April 14, while the average date for the first in fall is October 26, making the growing season about 195 days in length. Subzero weather in winter seldom occurs, averaging less than one day for December and one or two days each for January and February. The lowest temperature ever recorded in Providence has been 17° below zero (February 9, 1934).

Seventy-degree temperatures become common near the end of May, and usually cease the latter part of September. During this period, there may be several days with 90° and over, averaging near eight days per year. However, 90° temperatures have been recorded as early as March 29 (1945), and as late as October 10 (1949). Readings of 100° and over do not occur very often, and have been confined to the months of June, July and August. Some of the hottest days of summer come in August; the all-time high was 104° on August 2, 1975.

Measurable precipitation occurs on about one day out of every three, and is fairly evenly distributed throughout the year. The annual average is a little more than 42 inches, but this has varied from as little as 23.44 inches in 1965 to as much as 65.06 inches in 1972. The driest month of record was June 1949, with only 0.04 inches, while the wettest was August 1946, with 12.24 inches. There is usually no definite "dry season" but occasionally rather serious droughts are experienced; for example, the summer of 1949, when only 1 inch of rain fell during the months of June and July.

Thunderstorms are responsible for much of the rainfall from May through August. They usually produce heavy, and sometimes even excessive, amounts of rainfall; but since their duration is relatively short, damage is ordinarily light. The thunderstorms of summer are frequently accompanied by extremely gusty winds, which may result in some damage to property, especially small pleasure and fishing craft.

The first measurable snowfall of winter usually comes toward the end of November, and the last in spring is about the middle of March. The average snowfall for a winter season is close to 40 inches, ranging from as low as 11.3 inches in 1972-73 to as high as 75.6 inches in 1947-48. Only nine winters have had over 50 inches of snow, while 19 have had less than 25 inches. The month of greatest snowfall is usually February, but January and March are close seconds, with the record snowfall for any month being 31.9 inches in January 1948. It is unusual for the ground to remain well covered with snow for any long period of time. However, during the winter of 1947-48, there was a consistent snow cover from December 23 to March 18.
### Average Temperature

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<td>0.31</td>
<td>0.33</td>
<td>0.29</td>
</tr>
<tr>
<td>2018</td>
<td>0.18</td>
<td>0.13</td>
<td>0.15</td>
<td>0.19</td>
<td>0.21</td>
<td>0.23</td>
<td>0.25</td>
<td>0.27</td>
<td>0.29</td>
<td>0.31</td>
<td>0.33</td>
<td>0.35</td>
<td>0.31</td>
</tr>
<tr>
<td>2017</td>
<td>0.20</td>
<td>0.15</td>
<td>0.17</td>
<td>0.21</td>
<td>0.23</td>
<td>0.25</td>
<td>0.27</td>
<td>0.29</td>
<td>0.31</td>
<td>0.33</td>
<td>0.35</td>
<td>0.37</td>
<td>0.33</td>
</tr>
</tbody>
</table>

### Snowfall

| Year | Jan | Feb | Mar | Apr | May | June | July | Aug | Sept | Oct | Nov | Dec | January
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>2022</td>
<td>0.05</td>
<td>0.02</td>
<td>0.04</td>
<td>0.07</td>
<td>0.09</td>
<td>0.11</td>
<td>0.13</td>
<td>0.15</td>
<td>0.17</td>
<td>0.19</td>
<td>0.21</td>
<td>0.23</td>
<td>0.09</td>
</tr>
<tr>
<td>2021</td>
<td>0.07</td>
<td>0.03</td>
<td>0.05</td>
<td>0.08</td>
<td>0.10</td>
<td>0.12</td>
<td>0.14</td>
<td>0.16</td>
<td>0.18</td>
<td>0.20</td>
<td>0.22</td>
<td>0.24</td>
<td>0.10</td>
</tr>
<tr>
<td>2020</td>
<td>0.09</td>
<td>0.05</td>
<td>0.07</td>
<td>0.10</td>
<td>0.12</td>
<td>0.14</td>
<td>0.16</td>
<td>0.18</td>
<td>0.20</td>
<td>0.22</td>
<td>0.24</td>
<td>0.26</td>
<td>0.12</td>
</tr>
<tr>
<td>2019</td>
<td>0.11</td>
<td>0.07</td>
<td>0.09</td>
<td>0.12</td>
<td>0.14</td>
<td>0.16</td>
<td>0.18</td>
<td>0.20</td>
<td>0.22</td>
<td>0.24</td>
<td>0.26</td>
<td>0.28</td>
<td>0.14</td>
</tr>
<tr>
<td>2018</td>
<td>0.13</td>
<td>0.09</td>
<td>0.11</td>
<td>0.14</td>
<td>0.16</td>
<td>0.18</td>
<td>0.20</td>
<td>0.22</td>
<td>0.24</td>
<td>0.26</td>
<td>0.28</td>
<td>0.30</td>
<td>0.16</td>
</tr>
<tr>
<td>2017</td>
<td>0.15</td>
<td>0.11</td>
<td>0.13</td>
<td>0.16</td>
<td>0.18</td>
<td>0.20</td>
<td>0.22</td>
<td>0.24</td>
<td>0.26</td>
<td>0.28</td>
<td>0.30</td>
<td>0.32</td>
<td>0.18</td>
</tr>
</tbody>
</table>

* Indicates a station move or relocation of instruments. See station location table.

Record mean values above are means through the current year for the period beginning in 1980 for temperature and precipitation. Data for most years are from 1961-1990 locations through 1989-90 except that temperature are from the airport 1971-1980 and precipitation is from the airport 1971-1980 through 1989-90.

---

-8-
## STATION LOCATION

**PROVIDENCE, RHODE ISLAND**

<table>
<thead>
<tr>
<th>Location</th>
<th>Lat.</th>
<th>Long.</th>
<th>Elevation</th>
<th>Weather Station</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CITY</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>University Hall, Brown University, Prospect St.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bryant Building 15 Hope Street</td>
<td>41° 00'</td>
<td>-71° 38' 28&quot;</td>
<td>215 feet</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Turks Head Building 11 Hope Street</td>
<td>41° 00'</td>
<td>-71° 38' 28&quot;</td>
<td>215 feet</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Post Office Annex Bldg. Exchange Terrace (A)</td>
<td>41° 00'</td>
<td>-71° 38' 28&quot;</td>
<td>215 feet</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>AIRPORT</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Administration Building</td>
<td>41° 46'</td>
<td>-71° 38' 23&quot;</td>
<td>55 feet</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hangar Building No. 1</td>
<td>41° 46'</td>
<td>-71° 38' 23&quot;</td>
<td>55 feet</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Old Administration Bldg.</td>
<td>41° 46'</td>
<td>-71° 38' 23&quot;</td>
<td>55 feet</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Old Administration Bldg.</td>
<td>41° 46'</td>
<td>-71° 38' 23&quot;</td>
<td>55 feet</td>
<td></td>
<td></td>
</tr>
<tr>
<td>T.F. Green State Airport 1</td>
<td>41° 46'</td>
<td>-71° 38' 23&quot;</td>
<td>55 feet</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Old Administration Bldg.</td>
<td>41° 46'</td>
<td>-71° 38' 23&quot;</td>
<td>55 feet</td>
<td></td>
<td></td>
</tr>
<tr>
<td>T.F. Green State Airport 2</td>
<td>41° 46'</td>
<td>-71° 38' 23&quot;</td>
<td>55 feet</td>
<td></td>
<td></td>
</tr>
<tr>
<td>e Same effective on</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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I certify that this is an official publication of the National Oceanic and Atmospheric Administration, and is compiled from records on file at the National Climatic Center, Asheville, North Carolina 28801.

Director, National Climatic Center

U.S. DEPARTMENT OF COMMERCE
NATIONAL CLIMATIC CENTER
FEDERAL BUILDING
ASHEVILLE, N.C. 28801

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POSTAGE AND FEES PAID
U.S. DEPARTMENT OF COMMERCE

210 FIRST CLASS

-9-
ENTER IN CARD 6:

The maximum temperature of each month in R (degree Rankine form; \(0^\circ F = 459^\circ R\)) is to be entered in card 6.

If you cannot obtain the previously described publication for the area of this study, assume 59\(^\circ\)F (518\(^\circ\)R) for all values.

Columns: 1 thru 6: January
7 thru 12: February
13 thru 18: March
19 thru 24: April
25 thru 30: May
31 thru 36: June
37 thru 42: July
43 thru 48: August
49 thru 54: September
55 thru 60: October
61 thru 66: November
67 thru 72: December

Variable name: TMAX (month)
Month = 1, 12; (January thru December)
Data card sample on page 84.

ENTER IN CARD 7:

The minimum temperature of each month in R (degree Rankine form; \(0^\circ F = 459^\circ R\)) is to be entered in card 7.

If you cannot obtain the previously described publication for the area of this study, assume 59\(^\circ\)F (518\(^\circ\)R) for all values.

Columns: 1 thru 6: January
7 thru 12: February
13 thru 18: March
19 thru 24: April
25 thru 30: May
31 thru 36: June
37 thru 42: July
43 thru 48: August
49 thru 54: September
55 thru 60: October
61 thru 66: November
67 thru 72: December

Variable name: TMIN (month)
Month = 1, 12; (January thru December)
Data card sample on page 84.
If the system does not have any gas turbines, the number entered in column 1 of data card 4 is zero (0). Do not prepare data cards 8, 9, and 10.

Turn to page 15.

If the system has more than one gas turbine, the number entered in Column 1 of data card 4 is more than one. Prepare one set of data cards, numbers 8, 9, and 10, for each turbine. Place each set of data cards (numbers 8, 9, and 10) after each other in the data deck.

**EXAMPLE:** Turbine 1 data cards 8, 9, 10  
Turbine 2 data cards 8, 9, 10  
Turbine 3 data cards 8, 9, 10

**ENTER IN CARD 8:**

The design conditions for the gas turbine (refer to the table on page 12 for representative information).

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>the design output at full load; KW.</td>
<td>the design fuel consumption at full load; BTU/HR.</td>
<td>the design air flow; LBS/HR.</td>
<td>the compressor inlet temperature; R.</td>
<td>the compressor inlet pressure; PSIA.</td>
<td>the lower heating value of the fuel used, BTU/LB.</td>
</tr>
<tr>
<td></td>
<td>ED</td>
<td>QFD</td>
<td>AIRFLD</td>
<td>TAMBO</td>
<td>PAMBO</td>
<td>HV</td>
</tr>
</tbody>
</table>

If not known, use 519.

If not known, use 14.7.

If not known, use 18,300 to 19,800 BTU/LB for distillate oil, and 20,000 to 23,000 BTU/LB for natural gas.

Data card sample on page 85.
<table>
<thead>
<tr>
<th>GAS TURBINE MODEL NUMBER</th>
<th>OUTPUT KW</th>
<th>FUEL CONSUMPTION</th>
<th>AIRFLOW</th>
<th>STD. TEMP. (°F)</th>
<th>STANDARD PRESSURE (PSIA)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ALLISON 501-KB</td>
<td>2,500</td>
<td>30,214,000</td>
<td>88,148</td>
<td>59°F</td>
<td>14.7 PSIA</td>
</tr>
<tr>
<td>ALLISON 570-K</td>
<td>4,806</td>
<td>58,608,000</td>
<td>154,080</td>
<td>59°F</td>
<td>14.7 PSIA</td>
</tr>
<tr>
<td>GARRETT 1E 831-800</td>
<td>515</td>
<td>8,700,000</td>
<td>28,237</td>
<td>59°F</td>
<td>14.7 PSIA</td>
</tr>
<tr>
<td>GARRETT 1E 990-51</td>
<td>4,103</td>
<td>48,070,000</td>
<td>138,500</td>
<td>59°F</td>
<td>14.7 PSIA</td>
</tr>
<tr>
<td>GE 5341</td>
<td>24,200</td>
<td>298,900,000</td>
<td>928,500</td>
<td>59°F</td>
<td>14.7 PSIA</td>
</tr>
<tr>
<td>GEG 3142</td>
<td>10,150</td>
<td>138,550,000</td>
<td>408,800</td>
<td>59°F</td>
<td>14.7 PSIA</td>
</tr>
<tr>
<td>GEG 5261</td>
<td>18,900</td>
<td>252,000,000</td>
<td>767,000</td>
<td>59°F</td>
<td>14.7 PSIA</td>
</tr>
</tbody>
</table>

*NOTE: For COLUMNS 61-72, the LOWER HEATING VALUE, refer to page 11.*
ENTER IN CARD 9:

The "off-design" conditions for the gas turbine.

Use input information at a given partial load (say 1/2 load) in order to formulate the performance curves. If this information is not known, input zeros (0) for all. The calculation will be based on the already built-in performance curves.

<table>
<thead>
<tr>
<th>VARIABLE NAME</th>
</tr>
</thead>
<tbody>
<tr>
<td>Columns: 1 thru 12: the power output at the above given partial load; KW.</td>
</tr>
<tr>
<td>13 thru 24: the fuel consumption at the above given partial load; BTU/HR.</td>
</tr>
<tr>
<td>25 thru 36: the fuel consumption at the zero load (no power) condition; BTU/HR. If not known, input the value of 0.315 of design fuel consumption at full load, BTU/HR.</td>
</tr>
<tr>
<td>37 thru 48: the turbine exhaust gas temperature at full load, R.</td>
</tr>
<tr>
<td>49 thru 60: the turbine exhaust gas temperature at the above given partial load.</td>
</tr>
<tr>
<td>61 thru 72: the stack temperature, R. This will be normally about 50°F to 75°F higher temperature of the steam and with a low limit of 250°F to 300°F.</td>
</tr>
</tbody>
</table>

Data card sample on page 85.
THE HEAT RECOVERY BOILER

ENTER IN CARD 10:

<table>
<thead>
<tr>
<th>Columns:</th>
<th>DESCRIPTION</th>
<th>VARIABLE NAME</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 thru 10:</td>
<td>the steam pressure, PSIG.</td>
<td>STMPRE</td>
</tr>
<tr>
<td>11 thru 20:</td>
<td>the steam temperature, R.</td>
<td>STMTEP</td>
</tr>
<tr>
<td>21 thru 30:</td>
<td>the enthalpy of steam, BTU/LB.</td>
<td>STMENTH</td>
</tr>
<tr>
<td>31 thru 40:</td>
<td>the temperature of the feed water, R.</td>
<td>FETEMP</td>
</tr>
<tr>
<td>41 thru 50:</td>
<td>the enthalpy of the feed water, BTU/LB.</td>
<td>FEENTH</td>
</tr>
<tr>
<td>51 thru 60:</td>
<td>accounts for &quot;radiation&quot; losses from the waste heat recovery boiler. This is normally about 0.98 (decimal form).</td>
<td>EFFCTV</td>
</tr>
<tr>
<td>61 thru 70:</td>
<td>the effectiveness of the waste heat recovery boiler (decimal form).</td>
<td>EFFNS</td>
</tr>
</tbody>
</table>

Data card sample on page 86.
If the system does not have any diesel engines, the number entered in column 2 of data card 4 is zero (0). Do not prepare data cards 11 and 12. 

If the system has more than one diesel engine, the number entered in column 2 of data card 4 is more than one. Prepare one set of data cards (numbers 11 and 12) for each engine. Place each set of data cards, (numbers 11 and 12) after each other in the data deck.

**EXAMPLE:**
Engine 1 data cards 11 and 12
Engine 2 data cards 11 and 12
Engine 3 data cards 11 and 12

**ENTER IN CARD 11:**

For specific information refer to the manufacturer's data sheet. A similar data sheet is shown on pages 16 thru 21.

**VARIABLE NAME**

Columns: 1 thru 12: the net engine output at full load; KW
13 thru 24: the fuel consumption at full load; BTU/HR.
25 thru 36: the exhaust gas temperature at full load; R
37 thru 48: the exhaust gas temperature at a partial load; R. If not known, input zero.
49 thru 60: the power output at the above partial load; KW. If the exhaust gas temperature is input zero, input zero for this also.

Data card sample on page 87.

**ENTER IN CARD 12:**

Data on the exhaust heat recovery boiler for the diesel engine.

**VARIABLE NAME**

Columns: 1 thru 10: the intake air flow; LB/HR (#3 on the example data sheet)
11 thru 20: the stack temperature of gases leaving the boiler, R. This will be normally about 50°F to 75°F higher than the temperature of steam and with a lower limit of 710°F to 760°F.
21 thru 30: the steam pressure; PSIG.
31 thru 40: the steam temperature; R.
41 thru 50: the enthalpy of steam; BTU/LB.
51 thru 60: the temperature of the feed water; R.
61 thru 70: the enthalpy of the feed water; BTU/LB.
71 thru 80: accounts for "radiation" losses from the exhaust heat recovery boiler, normally about 0.98 (decimal form).

Data card sample on page 87.
Approximate dry weight: 13,200 Lb. 5990 Kg.

**PRIME POWER RATINGS**

<table>
<thead>
<tr>
<th></th>
<th>60 Hz @ 1200 RPM</th>
<th>50 Hz @ 1000 RPM</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>KW (g 0.8 P.F. (w/o fan))</strong></td>
<td>400</td>
<td>330</td>
</tr>
<tr>
<td><strong>KVA</strong></td>
<td>500</td>
<td>412.5</td>
</tr>
<tr>
<td><strong>Voltages Available</strong></td>
<td>125/216</td>
<td>200-400</td>
</tr>
<tr>
<td></td>
<td>230-460</td>
<td>230-460</td>
</tr>
<tr>
<td></td>
<td>2400</td>
<td>-</td>
</tr>
<tr>
<td><strong>Phase</strong></td>
<td>3</td>
<td>3</td>
</tr>
<tr>
<td><strong>Wire &amp; Connection</strong></td>
<td>10. Wye</td>
<td>10. Wye</td>
</tr>
</tbody>
</table>

**DIESEL ENGINE**

Four stroke cycle turbocharged—aftercooled diesel engine.

- Number of cylinders: V-8
- Bore and stroke: inches: 6.25 x 8.00
- Bore and stroke: millimeters: 159 x 203
- Piston displacement: cu. in.: 1964
- Piston displacement: liters: 32.2
- Compression ratio: 15.5:1
- Full load speed: 60 Hz 1200 RPM
- Full load speed: 50 Hz 1000 RPM
STANDARD EQUIPMENT
Dry, Single-Stage Air Cleaners
Flexible Fuel Lines
Fuel Filters
Fuel Priming and Transfer Pumps
Woodward UG8 Governor
(Isochronous Regulation)
Gear-Driven Jacket Water Pump
Water Temperature Gauge
Thermostats and Housing
Lube Oil Cooler and Filters
Lube Oil and Fuel Pressure Gauges
Tachometer Drive (SAE Standard)
Safety Shutoffs for Low Oil Pressure
and Overspeed
Mounting Rails
Service Meter
Dry, Water-Shielded Exhaust Manifolds
Lifting Eyes
Oil Pan (23° approx. max. tilt angle)

ATTACHMENTS
☐ Air Cleaner Service Indicator
☐ Alarm Switch
☐ Automatic Transfer Switch
☐ Auxiliary Drives
☐ Auxiliary Water Pump (Standard on Raw Water Aftercooled Engine)
☐ Charging Alternator
☐ Cooling Systems—Radiator, Heat Exchanger, Ebullient
☐ Exhaust Fittings
☐ Expansion Tank
☐ Glow Plugs
☐ Mufflers
☐ Precleaner
☐ Starting Systems—Air, Hydraulic, 30-32 Volt Electric
☐ Tachometer
☐ Wall-Mounted Control Panel
☐ Watercooled Exhaust Manifolds
☐ …

Additional attachments are available. Consult your Caterpillar representative for specific requirements.

SRCR GENERATOR
Construction:
Revolving-field, single bearing AC generator with built-in, statically-regulated, statically-excited system. Amortisseur windings function to oppose pulsation of the magnetic field, minimizing the hunting effect when generators are paralleled.

Excitation:
By rectified alternating current, Voltage buildup relay only moving part.

Regulation:
Silicon controlled rectifier, Transistorized voltage regulator, with no moving parts, automatically maintains voltage within ±2% from no load to full load. No external voltage regulator needed.

Insulation:
High temperature Class F insulation in stator and rotor.

Parallel Operation:
Cross current compensation standard.

Coupling:
Close-coupled, steel disc type.

Voltage Level:
Terminal voltage adjustable within ±5% of rated voltage (except 50 Hz 230-460 V, which is adjustable within +10% to −5%).

Voltage Droop:
Adjustable for proper division of reactive KVA when operating in parallel with other alternators.

Voltage Gain:
Adjustable to compensate for engine speed variation when operating with a speed droop governor.
RATINGS:
Prime Power — For continuous service with normally varying loads.
Maximum Power—Horsepower capability which can be demonstrated within 5% at the factory.

STANDARDS:
Ratings based on SAE standard conditions of 29.38 in. (748 mm) of mercury and 85°F (29°C).

ALTITUDE AND TEMPERATURE CAPABILITIES

<table>
<thead>
<tr>
<th></th>
<th>80 Hz</th>
<th>50 Hz</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1200 RPM</td>
<td>1000 RPM</td>
</tr>
<tr>
<td>3000 ft. and 80°F*</td>
<td>(900m) (27°C)</td>
<td>500 ft. and 85°F*</td>
</tr>
</tbody>
</table>

Between Operating Capability and 7000 ft. (2100m) and 60°F (16°C) derate .3% for each 1000 ft. (300m) and 1% for each 10°F (6°C), 16% for each 1000 ft. (300m) and 2% for each 10°F (6°C).

Above 7000 ft. and 80°F, consult your Caterpillar representative.

Fuel consumption applies to standard electric set engine W/O fan, based on fuel oil having a gross heat value of 19,500 BTU per pound (10,830K-cal/kg) and weighing 7.12 pounds per U.S. gallon (855 gm/ltr).

\[ KW = \text{BHP} \times 0.746 \times \text{generator efficiency}. \]
## Installation Facts

### FUEL SYSTEM

<table>
<thead>
<tr>
<th></th>
<th>60 Hz</th>
<th>50 Hz</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transfer pump</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cap. @ 85% eff. gpm @ line/sec</td>
<td>12.5</td>
<td>12.5</td>
</tr>
<tr>
<td></td>
<td>1.36</td>
<td>1.36</td>
</tr>
<tr>
<td>Cap.</td>
<td>5.42</td>
<td>4.52</td>
</tr>
<tr>
<td></td>
<td>3.51</td>
<td>2.85</td>
</tr>
</tbody>
</table>

### LUBRICATION SYSTEM

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Sump Capacity (Retail) gpm @ l</td>
<td>50</td>
<td>189.3</td>
</tr>
</tbody>
</table>

### COOLING WATER SYSTEM

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
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<tbody>
<tr>
<td>Volume gpm @ line</td>
<td>40</td>
<td>151.4</td>
</tr>
<tr>
<td>Water pump performance</td>
<td>28</td>
<td>106</td>
</tr>
<tr>
<td>Jacket Water</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capacity @ 30 ft</td>
<td>290</td>
<td>18.3</td>
</tr>
<tr>
<td></td>
<td>346</td>
<td>21.8</td>
</tr>
<tr>
<td>Max. Allowable Static Head ft</td>
<td>57.7</td>
<td>17.54</td>
</tr>
<tr>
<td>Auxiliary water</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capacity @ 20 ft</td>
<td>275</td>
<td>17.3</td>
</tr>
<tr>
<td></td>
<td>340</td>
<td>21.5</td>
</tr>
<tr>
<td>Max. Allowable Static Head ft</td>
<td>30</td>
<td>9.12</td>
</tr>
<tr>
<td>Maximum System Pressure psi</td>
<td></td>
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<tr>
<td>Water jacket</td>
<td>25</td>
<td>1.8</td>
</tr>
<tr>
<td>Aftercooler</td>
<td>40</td>
<td>2.9</td>
</tr>
<tr>
<td>Radiator</td>
<td>7</td>
<td>0.5</td>
</tr>
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### HEAT REJECTION

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>To Jacket Water (incl. standard manifolds, A/C, and oil cooler)</td>
<td>24500</td>
<td>6170</td>
</tr>
<tr>
<td>Temperature</td>
<td>210</td>
<td>99</td>
</tr>
<tr>
<td>Radiator data</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fan power HP @ 125°F. - 51°C. radiator</td>
<td>30</td>
<td>21.6</td>
</tr>
<tr>
<td>A. Flow through 125°F. - 51°C. radiator</td>
<td>38200</td>
<td>18028</td>
</tr>
<tr>
<td>Max. allowable static pressure @ exhaust side of radiator in mm H₂O with large radiator @ 100°F. - 38°C. ambient</td>
<td>5</td>
<td>12.7</td>
</tr>
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### ENGINE ROOM VENTILATION REQUIREMENTS

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>Combined Air requirements @ 85°F. - 29°C. cfm @ line/sec</td>
<td>1245</td>
<td>585</td>
</tr>
<tr>
<td>Heat radiated by engine btu/min @ kcal/min</td>
<td>1610</td>
<td>405</td>
</tr>
<tr>
<td>Heat dissipated by generator btu/min @ kcal/min</td>
<td>1478</td>
<td>372</td>
</tr>
<tr>
<td>Ventilation recommended for 15°F. - 9°C. rise (engine and generator radiated heat only) cfm @ line/sec</td>
<td>12150</td>
<td>5720</td>
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### EXHAUST SYSTEM

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Volume cfm @ line/sec</td>
<td>3260</td>
<td>1540</td>
</tr>
<tr>
<td>Gas Temperature °F. - °C. (Stack)</td>
<td>965</td>
<td>515</td>
</tr>
<tr>
<td>Max. Permissible Back Pressure in mm H₂O</td>
<td>20</td>
<td>508</td>
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</table>

### STARTING SYSTEM

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Air system</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Min. air pressure required at motor psi@ kcal/cm²</td>
<td>90</td>
<td>6.33</td>
</tr>
<tr>
<td>Max. air pressure allowed at motor psi@ kcal/cm²</td>
<td>150</td>
<td>10.33</td>
</tr>
<tr>
<td>Electric dual motor system</td>
<td></td>
<td></td>
</tr>
<tr>
<td>voltage</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Breakaway Current (Amps.)</td>
<td>1100</td>
<td>1100</td>
</tr>
<tr>
<td>@ 70°F. - 21°C.</td>
<td>1550</td>
<td>1550</td>
</tr>
<tr>
<td></td>
<td>140</td>
<td>440</td>
</tr>
<tr>
<td>@ 70°F. - 21°C.</td>
<td>620</td>
<td>620</td>
</tr>
<tr>
<td>@ 40°F. - 4°C.</td>
<td>620</td>
<td>620</td>
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</tbody>
</table>

*Material and specifications subject to change without notice.*
If the system does not have any auto extraction steam turbines, the number entered in column 3 of data card 4 is zero (0). Do not prepare data cards 13, 14, 15, and 16. Turn to page 38.

If the system has more than one auto extraction steam turbine, the number entered in column 3 of data card 4 is more than one. Prepare one set of data cards, numbers 13, 14, 15, and 16, for each turbine. Place each set of data cards (numbers 13, 14, 15, and 16) after each other in the data deck.

EXAMPLE: Turbine 1 data cards 13, 14, 15, and 16
Turbine 2 data cards 13, 14, 15, and 16
Turbine 3 data cards 13, 14, 15 and 16

Refer to the diagrams, performance maps, steam chart, and the General Electric publication for specific information. These are located on pages 24 thru 37.
### VARIABLE NAME AND SYMBOL ON CHARTS

<table>
<thead>
<tr>
<th>Variable Name</th>
<th>Symbol</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure of the throttle steam</td>
<td>PSIG.</td>
</tr>
<tr>
<td>Pressure of the extraction steam</td>
<td>PSIG.</td>
</tr>
<tr>
<td>Pressure of the exhausted steam</td>
<td>PSIG.</td>
</tr>
<tr>
<td>Temperature of the throttle steam</td>
<td>F.</td>
</tr>
<tr>
<td>Maximum generator output at a power factor of 1.00</td>
<td>KW.</td>
</tr>
<tr>
<td>Generator rated output</td>
<td>KW.</td>
</tr>
<tr>
<td>Correction to the extraction factor</td>
<td>T3LIM</td>
</tr>
<tr>
<td>Enthalpy of the throttle steam</td>
<td>TPNCHD</td>
</tr>
<tr>
<td>Enthalpy of the feed water to the boiler</td>
<td>TEXHD</td>
</tr>
<tr>
<td>Efficiency of the boiler for the steam turbine</td>
<td>T3FRC</td>
</tr>
<tr>
<td>Percentage of extracted steam to be exported</td>
<td>EFFCTV</td>
</tr>
<tr>
<td>Maximum throttle steam flow</td>
<td>LBS/HR.</td>
</tr>
<tr>
<td>Maximum extraction flow</td>
<td>LBS/HR.</td>
</tr>
<tr>
<td>Theoretical steam rate, from throttle to exhaust</td>
<td>LBS/KWH.</td>
</tr>
<tr>
<td>Theoretical steam rate, from throttle to extraction</td>
<td>LBS/KWH.</td>
</tr>
<tr>
<td>Half load non-extraction throttle flow factor</td>
<td>WC</td>
</tr>
<tr>
<td>Maximum exhaust flow</td>
<td>LBS/HR.</td>
</tr>
<tr>
<td>Minimum exhaust flow</td>
<td>LBS/HR.</td>
</tr>
<tr>
<td>Full load non-extraction efficiency of the turbine</td>
<td>decimal form</td>
</tr>
</tbody>
</table>

---

### Data card sample

**Card 13:**

<table>
<thead>
<tr>
<th>Columns</th>
<th>Variable Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 thru 12</td>
<td>Pressure of the throttle steam; PSIG.</td>
</tr>
<tr>
<td>13 thru 24</td>
<td>Pressure of the extraction steam; PSIG.</td>
</tr>
<tr>
<td>25 thru 36</td>
<td>Pressure of the exhausted steam; PSIG.</td>
</tr>
<tr>
<td>37 thru 48</td>
<td>Temperature of the throttle steam; F.</td>
</tr>
<tr>
<td>49 thru 60</td>
<td>Maximum generator output at a power factor of 1.00; KW.</td>
</tr>
<tr>
<td>61 thru 72</td>
<td>Generator rated output; KW</td>
</tr>
</tbody>
</table>

**Card 14:**

<table>
<thead>
<tr>
<th>Columns</th>
<th>Variable Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 thru 12</td>
<td>Correction to the extraction factor. This will be 0.857 for a condensing turbine and 0.902 for a non-condensing turbine.</td>
</tr>
<tr>
<td>13 thru 24</td>
<td>Enthalpy of the throttle steam.</td>
</tr>
<tr>
<td>25 thru 36</td>
<td>Enthalpy of the feed water to the boiler.</td>
</tr>
<tr>
<td>37 thru 48</td>
<td>Efficiency of the boiler for the steam turbine (decimal form).</td>
</tr>
<tr>
<td>49 thru 60</td>
<td>Percentage of extracted steam to be exported (decimal form). Accounts for steam used in plant.</td>
</tr>
<tr>
<td>61 thru 72</td>
<td>Maximum throttle steam flow; LBS/HR.</td>
</tr>
</tbody>
</table>

**Card 15:**

<table>
<thead>
<tr>
<th>Columns</th>
<th>Variable Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 thru 12</td>
<td>Maximum extraction flow; LBS/HR.</td>
</tr>
<tr>
<td>13 thru 24</td>
<td>Theoretical steam rate, from throttle to exhaust; LBS/KWH.</td>
</tr>
<tr>
<td>25 thru 36</td>
<td>Theoretical steam rate, from throttle to extraction; LBS/KWH.</td>
</tr>
<tr>
<td>37 thru 48</td>
<td>Half load non-extraction throttle flow factor.</td>
</tr>
</tbody>
</table>

**Card 16:**

<table>
<thead>
<tr>
<th>Columns</th>
<th>Variable Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 thru 12</td>
<td>Maximum exhaust flow; LBS/HR.</td>
</tr>
<tr>
<td>13 thru 24</td>
<td>Minimum exhaust flow; LBS/HR.</td>
</tr>
<tr>
<td>25 thru 36</td>
<td>Full load non-extraction efficiency of the turbine (decimal form)</td>
</tr>
</tbody>
</table>

---

---
AUTO EXTRACTION TURBINE

\[
\text{EFFECTV} = \frac{\text{Export Steam}}{\text{Export Steam} + \text{Plant Steam}}
\]

Note 1:
Due to limited storage space in the program (caused by dimensioning so many variable symbols used in steam turbine), computations are duplicates of those in combustion turbine section, but are not representative of the same physical quantities.

Note 2:
Input is used to define boundaries of steam turbine performance map of electrical output vs. throttle steam. See example.
Extraction/Condensing Turbine 700 psig, 750°F Throttle Steam
30 psig Extraction Pressure 1.5 psig Exhaust (Condenser) Pressure

Generator limit = 7,500 kW

Turbine Throttle Flow (1,000 lb/hr)

max throttle
flow = 111,700 lb/hr
(7,500, 111,700)

Max = 0 lb/hr
(3,174, 37,050)

min exhaust
flow = 3,000 lb/hr

EED

ED

Generator

(6348, 65,000)

point B

max extraction
flow = 50,000 lb/hr

70,000 lb/hr

50,000 lb/hr

21,085 lb/hr

Generator Output (kW)
A MOLLIER CHART FOR STEAM

Modified and greatly reduced from Kesten and
Laur's Thermodynamic Properties of Steam,
published (1938) by John Wiley and Sons, Inc.
Reproduced by permission of the publishers.

Enthalpy-entropy diagram for steam.

Copyright, 1940, by
Frank O. Kesten, William N. Laur
and Charles G. Merkley

-26-
Performance of Steam Turbines

Efficiency data necessary for calculating the detailed performance of condensing, noncondensing and single-automatic-extraction steam turbines in the ratings most commonly used in industrial plants is given in General Electric Turbine Handbook Section 4721.

Average figures for the efficiency of different turbines and methods of making very rough approximations of turbine performance were given in IPS data book sections .811 and .8111. These methods will be useful in quickly eliminating the least attractive alternates for a particular application.

It is intended that the data included in this section will be useful for quick determination of turbine performance within an accuracy of 5 percent or less. This should be adequate for all normal preliminary application studies.

AUTOMATIC EXTRACTION TURBINES
SINGLE AUTOMATIC EXTRACTION CONDENSING

A convenient calculating procedure and method of preparing a performance chart for a condensing, single-automatic extraction steam-turbine generator set will be outlined below. For the example, assume a unit rated 7500 kw—0.8 PF—9375 kva—3 phase—60 cycles with steam conditions as follows:

- Initial Steam: 600 psig—750 F
- Extraction Pressure: 50 psig
- Exhaust Pressure: 2 inches Hg absolute
- Max. Extraction Flow: 100,000 lb per hour

All of the calculations needed to prepare the performance chart for this turbine are shown in the calculation procedure below. The various steps are described in more detail in the text which follows the condensed calculation procedure.

Calculation Procedure

For determining performance of single-automatic extraction condensing steam turbines driving 60 cycle generators.

**CALCULATIONS**

- TSR = 7.09 lb per kw-hr = Theoretical Steam Rate, from throttle to exhaust (Fig. 3)
- TSR = 15.36 lb per kw-hr = Theoretical Steam Rate, from throttle to extraction (Fig. 3)
Performance of Steam Turbines

Efficiency = 0.715 (Fig. 4)

A = Full load nonextraction throttle flow
   \[ \frac{TSR_i \times \text{Rated Output}}{\text{Efficiency}} = \frac{7.09 \times 7500}{0.715} = 74,400 \text{ lb per hr} \]

B = Half load nonextraction throttle flow
   \[ \frac{1}{2} \times \text{A} = 37,200 \text{ lb per hr} \]

C = Extraction throttle flow at max. extraction flow
   \[ \frac{A + (E \times F)}{100,000} = 74,400 + (0.605 \times 100,000) = 134,900 \text{ lb per hr} \]

D = Min. flow to exhaust
   \[ 4200 \text{ lb per hr} \]
   \[ 4000 \text{ lb per hr} \]

M = Max. permissible throttle flow = 400,000 lb per hr (Fig. 8)

How to Draw Performance Chart

Plot points A, B, and C, and draw the straight lines indicated by Fig. 9 (the example is plotted on Fig. 10). Add the limits:

The minimum flow to exhaust limits is a straight line passing through the point on each line of constant extraction flow where the throttle flow is equal to the extraction flow plus the minimum exhaust flow (S).

The maximum flow to exhaust limit is a straight line passing through the point on each line of constant extraction flow where the throttle flow is equal to the extraction flow plus the full load nonextraction throttle flow (A).

The maximum throttle flow limit may be chosen at any value not in excess of the maximum permissible throttle flow (M), nor in excess of a flow equal to 3 times the full load nonextraction flow (3xA). It is

---

Fig. 2. Approximate steam rates of condensing steam turbine-generator units
Performance of Steam Turbines

usually taken as approximately equal to the full load throttle-flow at maximum required extraction (C).

Theoretical Steam Rates

The theoretical steam rates tabulated in Fig. 3 are based on representative initial steam conditions. Inasmuch as each column is headed by both an initial pressure and an initial temperature, this condensed table is not well suited to interpolations.

Where steam conditions are other than those shown in this table, the theoretical steam rates may be derived from a Mollier chart, or read directly from a comprehensive set of Theoretical Steam Rate Tables such as those by Keenan & Kyes, published by the ASME in 1938 and reproduced in General Electric Handbook Section 4707.

Care should be used in determining the theoretical steam rates; they are factors that influence greatly the result.

Efficiency

An approximation of the full-load efficiency with no extraction for single-automatic extraction condensing turbines is given in Fig. 4. The efficiencies

<table>
<thead>
<tr>
<th>Initial Pressure—Lb per sq in. Gage</th>
<th>Initial Temperature—Degrees Fahrenheit</th>
</tr>
</thead>
<tbody>
<tr>
<td>150</td>
<td>200</td>
</tr>
<tr>
<td>220</td>
<td>250</td>
</tr>
<tr>
<td>350</td>
<td>400</td>
</tr>
<tr>
<td>500</td>
<td>600</td>
</tr>
<tr>
<td>650</td>
<td>850</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Steam Rate—Lb per sq in. Gage</th>
<th>Heat Rate—Btu per lb of Steam</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.0</td>
<td>2.0</td>
</tr>
<tr>
<td>3.0</td>
<td>4.0</td>
</tr>
<tr>
<td>5.0</td>
<td>6.0</td>
</tr>
</tbody>
</table>

From "Theoretical Steam Rate Table" by Keenan & Kyes published in 1938 by ASME.

Fig. 3. Condensed Table of Theoretical Steam Rates
taken from this table are in the proper magnitude but may be higher or lower than the actual performance guarantees for a specific turbine. If, for example, a turbine were designed to favor performance at high extraction flows, it is probable that the performance guarantees for such a turbine at full load with no extraction would be somewhat poorer than the efficiencies estimated in Fig. 4. In most cases, regardless of design, the error for efficiencies read from this table will be less than 5 percent.

**Half-load Flow-factor**

The half-load flow-factors (Fig. 5) are approximations that assume that the throttle flow versus output curve at no extraction will be a straight line. The table assumes, too, that all turbines of the same rating, regardless of design, will have the same half-load flow to full-load flow relationship. Obviously this relationship is not a constant one, but the error
Performance of Steam Turbines

The extraction factor is the portion of a pound of steam which must be added to the throttle flow for each pound of steam extracted. Its use is shown in the example.

Max. Required Extraction Flow

The maximum required extraction flow is part of the given conditions for each application of an extraction turbine. No problem is presented by this flow when it is small, but sometimes the desired extraction flow is beyond the turbine's capacity. In such a case the maximum throttle flow limit line (discussed under the heading "Max. throttle flow") will cut off the maximum extraction at the point where full-load is developed with minimum steam flow passing to the exhaust section.

When selecting a flow for the maximum required extraction flow, it will be found desirable to pick a number easily divisible into smaller flows. This is apparent on Fig. 10 where the 100,000 lb per hr flow has been divided into flows of 20, 40, 60, 80, and 100,000 lb per hr for convenience in reading the chart.

Minimum Flow to Exhaust

The chart of minimum flow to exhaust is plotted against extraction pressure with lines for different turbine ratings in Fig. 7. It is not necessary to read this chart more closely than the nearest 500 lb per hr.

The minimum steam flow to exhaust must be adequate to cool the exhaust stages of the turbine. Fig. 9 gives the steps necessary to prepare the performance chart up to the point where limits are added. The first limit usually added to such a chart is the limit of minimum flow to exhaust, sometimes called the limit of maximum extraction inasmuch as it acts to limit maximum extraction. To add this limit to the chart, two or three points should be plotted...
Performance of Steam Turbines

The maximum flow to exhaust limit is added to the hort in exactly the same manner as the minimum low to exhaust limit was added. In this estimating method the assumption has been made that all tur-

bines will be designed with exhaust sections sufficiently large to enable the turbine to carry full rated output with the extraction pressure held constant but no extraction taken from the turbine. This is the usual practice with condensing extraction turbines, although cases are occasionally encountered when it is not sufficient to make the exhaust section larger or smaller than the general rule.

In adding the maximum flow to exhaust limit, the lines of constant extraction flow should be extended 0 the point where they are cut off by this limit or by the limit of generator output. Thus, on Fig. 10, the 20,000 lb per hr extraction flow line is cut by the limit at a throttle flow of 94,400 lb per hr (20,000 lb per hr plus point A), but the 69,000 lb per hr extraction line is cut off by the limit of generator output, 9375 kw at 1.0 power factor.

Maximum Generator Output

The usual turbine generator set has an 0.80 power factor generator, and a turbine capable of carrying all kva on the generator at 1.0 power factor. This is indicated as 125 per cent capacity on Fig. 9 and as 10.1 kw at 1.0 power factor on Fig. 10.

Maximum Throttle Flow

The maximum throttle flow from Fig. 8 is not a true limit in the sense that turbines of the ratings shown could not be built for higher steam flows. Rather it is intended as a warning that such a turbine would be of special design. So also is the limit imposed by a throttle flow equal to three times the full-
load nonextraction flow (i.e. 3X A). Both of these maximum throttle flow limits are exceeded by many actual extraction turbines, but performance of such machines is outside the range of this method. When application of turbines outside these limits is indicated, a manufacturer's turbine specialist or an application engineer familiar with detailed turbine performance should prepare even the most preliminary of estimates.

This estimating method does not include any change in performance for differences in the maximum throttle flow alone. Actually, performance under a given condition will be better if the turbine is designed for a flow no greater than that required to meet the particular condition than if the turbine is designed for a flow much greater than needed. If, for example, the performance of Fig. 10 had been estimated for 150,000 lb per hr extraction flow, the estimated throttle flow at 100,000 lb per hr extraction would remain unchanged, on the basis of this method. In an actual turbine, performance would be better for a turbine designed and operating at 100,000 lb per hr extraction, than for a turbine otherwise the same except designed for 150,000 lb per hr but operating at 100,000 lb per hr extraction. Because of this, the maximum throttle flow should be selected at the lowest value consistent with flexibility to meet present and future needs.

It is true that performance of the condensing extraction type of turbine is easily estimated; it is true that performance of this type of turbine usually pleases both power plant operators and owners. But care should be taken to have each purchase of these turbines approved by an engineer skilled in their application. Only then can assurance be had that these useful machines are making all the gain possible from each particular set of operating conditions.

SINGLE-AUTOMATIC EXTRACTION NONCONDENSING

The Calculation Procedure for determining and plotting the performance of single-automatic extraction noncondensing steam turbines is similar to that for the single-automatic extraction condensing units. The various steps will not be covered in detail as was done in the previous example but a step-by-step calculation procedure for a specific turbine will be worked out below with reference being made to the various curves which give the efficiency and other factors necessary.

For the example, assume a unit rated 7500 kw—
0.8 PF—9375 kva—3 phase—60 cycles with steam conditions as follows:

<table>
<thead>
<tr>
<th>Initial Steam</th>
<th>Extraction Pressure</th>
<th>Exhaust Pressure</th>
<th>Max. Extraction Flow</th>
</tr>
</thead>
<tbody>
<tr>
<td>600 psig—750 F</td>
<td>150 psig</td>
<td>40 psig</td>
<td>200,000 lb per hr</td>
</tr>
</tbody>
</table>

Calculation Procedure

For determining performance of single-automatic

<table>
<thead>
<tr>
<th>Rating in Kva at 0.8 PF</th>
<th>150</th>
<th>200</th>
<th>250</th>
<th>300</th>
<th>400</th>
<th>600</th>
<th>850</th>
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<tbody>
<tr>
<td>Efficiency</td>
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</tr>
<tr>
<td>3000</td>
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</tr>
<tr>
<td>500</td>
<td>310</td>
<td>310</td>
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</tr>
</tbody>
</table>

Fig. 11. Full-load non-extraction efficiency of noncondensing single-automatic extraction steam turbines
Performance of Steam Turbines

noncondensing steam turbine driving 60-cycle generators.

**Calculations**

- **TSR₁** = 14.51 lb per kw/hr = Theoretical Steam Rate from throttle to exhaust (Fig. 3)
- **TSR₂** = 23.83 lb per kw/hr = Theoretical Steam Rate, from throttle to extraction (Fig. 3)
- Efficiency = 0.715 (Fig. 11)

**A** = Full-load nonextraction throttle flow

\[ \text{TSR₁} \times \text{Rated Output} \] = 14.51 \times 7500 \] = 152,300 lb per hr

**B** = Half-load nonextraction throttle flow

\[ \text{A} \times \text{half-load flow factor (Fig. 12)} \] = 152,300 \times 0.62 = 94,500 lb per hr

**C** = Full-load throttle flow at max. required extraction flow

\[ \text{A} + (\text{EXF}) = 152,300 + (0.45 \times 200,000) = 242,300 \text{ lb per hr} \]

**D** = Min. flow to exhaust

\[ \text{Max. permissible throttle flow} = 400,000 \text{ lb per hr (Fig. 8)} \]

How to Draw Performance Chart

Plot points A, B, and C, and draw straight lines indicated by Fig. 9. Complete the performance chart similar to Fig. 10, as described in the Calculation Procedure for a single-automatic extraction unit.

**Double-Automatic, Extraction Condensing**

Calculations required to obtain a complete performance chart for a Double-automatic, Extraction Condensing steam turbine have also been reduced to a method that involves only a few steps of simple arithmetic. Although a completed performance chart may look rather complex at first glance, it is very easy to plot and very easy to use.

To illustrate how easily a complete performance chart can be prepared, a step-by-step calculation procedure for a specific steam turbine will be worked out below with reference being made to the various curves with the efficiency and other factors necessary.

For the example, assume a unit rated 6000 kw - 0.8 PF - 9375 kva - 3 phase - 60 cycles with steam conditions as follows:

<table>
<thead>
<tr>
<th>Initial Steam Pressure</th>
<th>Required Flow</th>
</tr>
</thead>
<tbody>
<tr>
<td>High Pressure Extraction</td>
<td>150 psig</td>
</tr>
<tr>
<td>Low Pressure Extraction</td>
<td>40 psig</td>
</tr>
<tr>
<td>Exhaust</td>
<td>2 inches H₂O absolute</td>
</tr>
</tbody>
</table>

**Max. Pressure**

| TSR₁ = 7.09 lb per kw/hr = Theoretical Steam Rate, from throttle to exhaust (Fig. 3) |
| TSR₂ = 23.83 lb per kw/hr = Theoretical Steam Rate, from throttle to high-pressure extraction (Fig. 3) |
| Efficiency = 0.92 (Fig. 14) |
Performance of Steam Turbines

Full-load nonextraction throttle flow

\[
\text{Efficiency} = \frac{7.09 \times 7500}{0.69} = 77,100 \text{ lb per hr}
\]

Half-load nonextraction throttle flow

\[
\text{TSR}_{1} = 7.09 \\
\text{TSR}_{2} = 23.83 \\
E_{HP} = \text{High-pressure extraction factor} = 0.77 \text{ (Fig. 16)}
\]

Low-pressure extraction factor = 0.56 \text{ (Fig. 16)}

Max. required high-pressure extraction flow = 150,000 lb per hr

Max. required low-pressure extraction flow = 125,000 lb per hr

Full-load throttle flow at max. required low-pressure extraction flow, but zero high-pressure extraction flow

\[
A = \text{Max. permissible throttle flow (Fig. 8)}.
\]

How to Draw Performance Chart

Prepare a table of limits:

<table>
<thead>
<tr>
<th>Section of Turbine</th>
<th>Limiting Flow, in Lb per Hr</th>
</tr>
</thead>
<tbody>
<tr>
<td>High Pressure</td>
<td>Maximum: 231,300, Minimum: 0</td>
</tr>
<tr>
<td>Intermediate</td>
<td>Maximum: 147,100, Minimum: 6500</td>
</tr>
<tr>
<td>Low pressure</td>
<td>Maximum: 77,100, Minimum: 4000</td>
</tr>
</tbody>
</table>

Note 1. Take the least of the following for max. high-pressure section flow:

\[
M \text{ or } 3 \times A, \text{ or } D + (E_{HP} \times F_{HP})
\]

Max. permissible throttle flow (Fig. 8) = 262,600 lb per hr

Note that the example problem includes the mini-
Performance of Steam Turbines

mum data needed to prepare a performance chart. These minimum conditions are: the rated output, the steam conditions, and the desired maximum extraction flows.

It is usually easier to complete the arithmetic of the calculation procedure before starting to plot the performance chart than in drawing the chart. This first point, the full-load nonextraction flow, designated as "A," is the basic point used as a pivot for determining the other points. An error made in determining this point will reflect itself throughout all remaining points.

The fact that this basic point A, and the remaining three points, are all so easily determined is the greatest disadvantage of this method. Most engineering calculations are of such a complex nature that rule of thumb and other short-cut checks can be made to catch a gross error. Not so in this method. All of the short-cuts have been taken—any check calculation would be long and cumbersome—so, even though this method takes less than ten minutes of simple arithmetic, take the time to recheck each figure. The slight additional effort is more than repaid by the confidence that can be put in the result.

Plotting the Performance Chart

Fig. 18 shows the steps to take in plotting the data derived in the calculation procedure, and Fig. 19 is the performance chart that resulted from plotting the example problem. Do not be misled by the complex appearance of these charts. They are nothing but straight lines, equally spaced, and parallel to each other. More time may be spent in choosing the scales than in drawing the chart.

Steps 1 and 2 are simple enough, but Step 3 seems unusual. It isn't, however, and no error will be introduced by choosing a slope for the reference line other than 45 degrees. The throttle flow axis can be located at any point, too, but for simplicity it is usually moved enough to the left to prevent overlapping of the high-pressure and low-pressure portions of the performance chart.

Step 4 consists simply in plotting throttle-flow D at a point directly above the reference line corresponding to full-load with no low-pressure extraction, or, in other words, point A. Then a line is drawn through point D, parallel to the reference line.

Except for limits, the chart is completed in Step 5 by drawing lines of constant extraction flow equally spaced and parallel between zero extraction and the maximum. Figure 19, for example, shows low-pressure constant extraction flow lines of 25,000, 50,000, 75,000 and 100,000 lb per hr drawn between 0 and 125,000 lb per hr extraction. And high-pressure constant extraction flow lines of 50,000 and 100,000 lb per hr drawn between 0 and 150,000 lb per hr extraction. These lines are simply for convenience in reading the chart. Their position may be fixed by using dividers, or by a couple of triangles and simple geometry, or by calculation. If calculation is preferred, in should be remembered that each line of constant extraction flow is separated from its neighbor by a distance equal to the extraction flow difference times the extraction factor. Thus, in the case of Fig. 19, each of the lines of high pressure extraction flow are separated by a distance equal to 50,000 x 0.77 or 38,500 lb per hr and the low pressure lines by a distance equal to 25,000 x 0.56 or 14,000 lb per hr.

Adding the Limits to the Chart

Rather than add all of the limits to the performance chart, it will usually be found time saving to add only a few of the limits and rely on the table of limits for those not shown on the chart. The table of limits derived, as shown in the calculation procedure, is used by reading any desired point from the extraction chart and then checking to see that the flow through the turbine's high-pressure, intermediate, and low-pressure sections are within the limits given in the table. This is done by using the following simple formulae:
Performance of Steam Turbines

Fig. 18. Step-by-step method of constructing the performance chart

Fig. 19. Performance chart of the 7500-hp condensing double-automatic extraction steam turbine used in the example. Initial steam conditions: 600 psig—750 F. High pressure extraction: 150 psig. Low pressure extraction: 40 psig. Exhaust pressure: 2 inches Hg absolute
Performance of Steam Turbines

High-pressure section flow = throttle flow
Intermediate section flow = throttle flow minus high-pressure extraction flow
Low-pressure section flow = throttle flow minus high-pressure extraction flow minus low-pressure extraction flow

To show, by example, how this works, follow the ashed line on Fig. 19 which shows that:

At an output of 6000 kw with low-pressure extraction of 50,000 lb per hr and high-pressure extraction of 100,000 lb per hr the throttle flow is 170,000 lb per hr.

Thus,

High-pressure section flow = 170,000 lb per hr
Intermediate section flow = 170,000 – 100,000 = 70,000 lb per hr
Low-pressure section flow = 170,000 – 100,000 – 50,000 = 20,000 lb per hr

In each case, these flows are between the maximum and minimum section flow limits shown by the table. The limits given in the table can be plotted on the chart, but the resultant maze of lines may be more confusing than helpful. Usually it suffices to draw on the chart the maximum throttle flow limit, and the maximum generator output limit.

Conclusion

The short-cut methods described in this section give approximations within five per cent in the usual case, but do not show possible gains from any special conditions of operation that exist in most industries. Manufacturers' turbine specialists or application engineers familiar with turbine applications should be consulted early in studies involving these useful turbines—they are experienced in taking into account the variables that affect the design of each machine.
If the system does not have any back pressure steam turbines, the number entered in column 4 of data card 4 is zero (0). Do not prepare data cards 17 and 18. Turn to page 43.

If the system has more than one back pressure steam turbine, the number entered in column 4 of data card 4 is more than one. Prepare one set of data cards (numbers 17 and 18) for each turbine. Place each set of data cards (numbers 17 and 18) after each other in the data deck.

**EXAMPLE:**
- Turbine 1 data cards 17 and 18
- Turbine 2 data cards 17 and 18
- Turbine 3 data cards 17 and 18

Refer to the diagram, steam chart and the General Electric publication for specific information. These are located on pages 40 thru 42.
ENTER IN CARD 17:

Columns: 1 thru 12: the rated power output at full load; KW. EED
13 thru 24: the steam rate or water rate at full load; LB/KWH. QFD
25 thru 36: the power output at a partial load KW. EDP
37 thru 48: the steam rate or water rate at above partial load, (EDP); LB/KWH. QFP
49 thru 60: the efficiency of boiler, decimal form. T3FRC
61 thru 72: the percentage of exhaust steam to be exported (decimal form). Accounts for steam used in plant. T3LIM

Data card sample on page 90.

ENTER IN CARD 18:

Columns: 1 thru 12: the enthalpy of the throttle steam; BTU/LB. TPNCHD
13 thru 24: the pressure of the throttle steam; PSIG. PAMBD
25 thru 36: the temperature of the throttle steam; F. TAMBD
37 thru 48: the pressure of the exhaust steam; PSIG. WTD
49 thru 60: the temperature of the exhaust steam; F. STMD
61 thru 72: the enthalpy of the feed water to the boiler; BTU/LB. TEXHD

Data card sample on page 90.
BACK PRESSURE TURBINE

Throttle Steam
PAMBD, TAMBD

Boiler Efficiency
T3FRC

Feedwater
TEXHD

QFD from GE
QFP from GE

WTD
STMP

Exhaust Steam

EED
EUP

Plant Steam

Export Steam

T3LIM = \frac{\text{Export Steam}}{\text{Export & Plant Steam}}
A MULLER CHART FOR STEAM

Modified and greatly reduced from Levine and Loomis' Thermodynamic Properties of Steam, published (1940) by John Wiley and Sons, Inc. Reprinted by permission of the publisher.

Enthalpy-entropy diagram for steam.
Efficiency data necessary for calculating the detailed performance of condensing, noncondensing and single-automatic-extraction steam turbines in the ratings most commonly used in industrial plants is given in General Electric Turbine Handbook Section 4721.

Average figures for the efficiency of different turbines and methods of making very rough approximations of turbine performance were given in IPS data book sections .811 and .8111. These methods will be useful in quickly eliminating the least attractive alternates for a particular application.

It is intended that the data included in this section will be useful for quick determination of turbine performance within an accuracy of 5 percent or less. This should be adequate for all normal preliminary application studies.

NONEXTRACTION TURBINES

The data plotted on Fig. 1 shows the steam consumed by noncondensing steam turbines rated 2000 kw through 15,000 kw at various load conditions.
ELECTRICAL LOAD ON A TYPICAL WORK DAY

Prepare one set of data cards 19, 20, and 21 for each month.

Place each set of data cards (numbers 19, 20, and 21) after each other in the data deck.

EXAMPLE: January - data cards 19, 20, and 21
February - data cards 19, 20, and 21
March - data cards 19, 20, and 21

Continue preparing the data cards until you have 12 sets (January thru December)

Enter the value of the electrical load (KW) of each hour on a typical work day.

ENTER IN CARD 19:
Columns: 1 thru 10: 0100
         11 thru 20: 0200
         21 thru 30: 0300
         31 thru 40: 0400
         41 thru 50: 0500
         51 thru 60: 0600
         61 thru 70: 0700
         71 thru 80: 0800

ENTER IN CARD 20:
Columns: 1 thru 10: 0900
         11 thru 20: 1000
         21 thru 30: 1100
         31 thru 40: 1200
         41 thru 50: 1300
         51 thru 60: 1400
         61 thru 70: 1500
         71 thru 80: 1600

ENTER IN CARD 21:
Columns: 1 thru 10: 1700
         11 thru 20: 1800
         21 thru 30: 1900
         31 thru 40: 2000
         41 thru 50: 2100
         51 thru 60: 2200
         61 thru 70: 2300
         71 thru 80: 2400

Variable name: ELLD (IHR, Month, Nowork)
IHR = 1, 24; (Hours - 0100 thru 2400)
Month = 1, 12; (January thru December)
Nowork = 1; (Work day)

Data card samples on page: 91 and 92.
ELECTRICAL LOAD ON A TYPICAL NON-WORK DAY

Prepare one set of data cards 22, 23, and 24 for each month.

Place each set of data cards (numbers 22, 23, and 24) after each other in the data deck.

EXAMPLE: January - data cards 22, 23, and 24
February - data cards 22, 23, and 24
March - data cards 22, 23, and 24

Continue preparing the data cards until you have 12 sets (January thru December).

Enter the value of the electrical load (KW) of each hour on a typical non-work day.

ENTER IN CARD 22:
Columns:
1 thru 10: 0100
11 thru 20: 0200
21 thru 30: 0300
31 thru 40: 0400
41 thru 50: 0500
51 thru 60: 0600
61 thru 70: 0700
71 thru 80: 0800

ENTER IN CARD 23:
Columns:
1 thru 10: 0900
11 thru 20: 1000
21 thru 30: 1100
31 thru 40: 1200
41 thru 50: 1300
51 thru 60: 1400
61 thru 70: 1500
71 thru 80: 1600

ENTER IN CARD 24:
Columns:
1 thru 10: 1700
11 thru 20: 1800
21 thru 30: 1900
31 thru 40: 2000
41 thru 50: 2100
51 thru 60: 2200
61 thru 70: 2300
71 thru 80: 2400

Variable name: ELLO (IHR, Month, Nowork)
IHR = 1, 24; (Hours - 0100 thru 2400)
Month = 1, 12; (January thru December)
Nowork = 2; (Non-work day)

Data card samples on pages 93 and 94.
STEAM LOAD ON A TYPICAL WORK DAY

Prepare one set of data cards 25, 26, and 27 for each month.

Place each set of data cards (numbers 25, 26, and 27) after each other in the data deck.

EXAMPLE: January - data cards 25, 26, and 27
February - data cards 25, 26, and 27
March - data cards 25, 26, and 27

Continue preparing the data cards until you have 12 sets (January thru December).

Enter the value of the steam load (LB/HR) of each hour on a typical work day.

ENTER IN CARD 25:
Columns: 1 thru 10: 0100
11 thru 20: 0200
21 thru 30: 0300
31 thru 40: 0400
41 thru 50: 0500
51 thru 60: 0600
61 thru 70: 0700
71 thru 80: 0800

ENTER IN CARD 26:
Columns: 1 thru 10: 0900
11 thru 20: 1000
21 thru 30: 1100
31 thru 40: 1200
41 thru 50: 1300
51 thru 60: 1400
61 thru 70: 1500
71 thru 80: 1600

ENTER IN CARD 27:
Columns: 1 thru 10: 1700
11 thru 20: 1800
21 thru 30: 1900
31 thru 40: 2000
41 thru 50: 2100
51 thru 60: 2200
61 thru 70: 2300
71 thru 80: 2400

Variable Name: STMLD (IHR, Month, Nowork)
IHR = 1, 24; (Hours - 0100 thru 2400)
Month = 1, 12; (January thru December)
Nowork = 1; (Work day)

Data card samples on pages 95 and 96.
STEAM LOAD ON A TYPICAL NON-WORK DAY

Prepare one set of data cards 28, 29, and 30 for each month.

Place each set of data cards (numbers 28, 29, and 30) after each other in the data deck.

EXAMPLE: January - data cards 28, 29, and 30
February - data cards 28, 29, and 30
March - data cards 28, 29, and 30

Continue preparing the data cards until you have 12 sets (January thru December).

Enter the value of the steam load (LB/HR) of each hour on a typical non-work day.

ENTER IN CARD 28:
Columns:
1 thru 10: 0100
11 thru 20: 0200
21 thru 30: 0300
31 thru 40: 0400
41 thru 50: 0500
51 thru 60: 0600
61 thru 70: 0700
71 thru 80: 0800

ENTER IN CARD 29:
Columns:
1 thru 10: 0900
11 thru 20: 1000
21 thru 30: 1100
31 thru 40: 1200
41 thru 50: 1300
51 thru 60: 1400
61 thru 70: 1500
71 thru 80: 1600

ENTER IN CARD 30:
Columns:
1 thru 10: 1700
11 thru 20: 1800
21 thru 30: 1900
31 thru 40: 2000
41 thru 50: 2100
51 thru 60: 2200
61 thru 70: 2300
71 thru 80: 2400

Variable Name: STMLD (IHR, Month, Nowork)
IHR = 1, 24; (Hours - 0100 thru 2400)
Month = 1, 12; (January thru December)
Nowork = 1; (Non-work day)

Data card samples on pages 97 and 98.
The rate structures of the utility companies vary as to geographic location. Demand pricing is generally used by the eastern states. Time of day pricing is generally used by the western states. Contact the utility company to determine the rate structure applicable to this study.

Refer to pages 48 thru 52 for typical examples of rate structures for the West and East coast.

ENTER IN CARD 31:

<table>
<thead>
<tr>
<th>Columns</th>
<th>Name</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 thru 5: the month during which the summer rate begins (numeric form; ex: May = 5).</td>
<td>SUMON1</td>
</tr>
<tr>
<td>6 thru 10: the month during which the winter rate begins (numeric form; ex: November = 11).</td>
<td>SUMON2</td>
</tr>
</tbody>
</table>

This data is used in conjunction with the time of day rate scheduling. They are "dummy" variables in the version of CELCAP with the demand rate schedule.

Data card sample on page 99.

If the rate structure to be used is demand pricing:

Enter in data cards 32, 33, 34, and 35, columns 1 thru 24, 1.

Data card samples on pages 100 and 101.

TURN TO PAGE 57.

This is simply a "dummy" variable for the version of CELCAP with the demand pricing rate schedule.

If the rate structure to be used is time of day pricing: TURN TO PAGE 53.
WHOLESALE POWER SERVICE

AVAILABILITY:

Service is available hereunder for any power purchases, but not for resale, to any customer who will enter into a contract, satisfactory to Company, to purchase all of its requirements of electric energy for power purposes from the Company for a period of not less than five (5) years provided Company has adequate generating and/or transmission facilities available to serve such customers over and above the requirements of existing customers. Service shall be supplied through a single point of delivery and one metered supply unless for the sole convenience of Company more than one delivery point or one metered supply will be provided. Electric energy for the lighting purposes of customer may also be purchased hereunder provided customer supplies and maintains the necessary transformers thereafter.

CHARACTER OF SERVICE:

Service supplied hereunder shall be three phase, 60 cycle electric energy at a nominal voltage of 23,000 volts, or higher.

RATE:

Demand Charge:

First 5,000 kw of billing demand or less per month - $16,650

All additional kw of billing demand - 2.30 per kw

Energy Charges:

First 340 hours use of billing demand per month - 3.07c per kwh

All additional kwh used per month - 2.79c per kwh

DETERMINATION OF BILLING DEMAND:

The billing demand in kilowatts for each month shall be the greater of (a) the maximum demand adjusted for power factor each month, (b) 75% of the maximum billing demand established by customer during any of the immediately preceding eleven months, (c) 50% of the maximum billing demand established by customer during the life of the contract, or (d) 5,000 kilowatts.
POWER FACTOR ADJUSTMENT:

For billing demand purposes, when the power factor of customer as measured hereunder is above 80% lagging and below 90% lagging no adjustment of the maximum demand as measured in kilowatts for each billing month shall be made. When the power factor of customer as measured hereunder shall in any month fall below 80% lagging, then the demand measured hereunder shall be adjusted by multiplying by 90% and dividing by the power factor expressed as a percentage. When the power factor of customer as measured hereunder shall in any month rise above 90% lagging, then the demand measured hereunder shall be adjusted by multiplying by 90% and dividing by the power factor expressed as a percentage. For the purposes of the faster adjustment, the power factor shall in no event by considered as greater than unity.

MINIMUM CHARGE:

The monthly minimum charge for service hereunder shall be the demand charge plus the energy charge for 170 hours use of the billing demand of such month, subject to Fuel, Primary Metering and Transformer Ownership adjustments.

FUEL ADJUSTMENT CLAUSE:

All energy delivered hereunder, including the amount in the minimum charge, shall be subjected to the provisions of the Company's Standard Fuel Adjustment Clause.

PRIMARY METERING:

If the electric energy delivered to customer is measured at the line voltage, not less than 23,000 volts, at which it is transmitted to the point of delivery hereunder, there will be credited against the amount determined under the preceding provisions two and one-half percent (2-1/2%) of the demand charge and energy charge for such month.

TRANSFORMER OWNERSHIP:

If customer utilizes electric energy at the line voltage, not less than 23,000 volts, at which it is transmitted to the point of delivery hereunder or if customer provides all transformers which may be required to reduce the line voltage to the level at which the electric energy is to be used by customer, there will be credited against the amount determined under the preceding provisions twelve cents ($0.12) for each kilowatt of billing demand for such month.
TERMS AND CONDITIONS:

(1) Service hereunder shall be subject to the Company's Terms and Conditions in effect from time to time and not inconsistent with any specific provisions of this rate schedule.

(2) The term "year" shall mean each twelve-month period beginning after the date of the first delivery of electric energy to customer under this rate schedule.

(3) The term "demand" shall mean customer's maximum average rate of taking electric energy hereunder during any fifteen-minute period during the billing month as measured by a standard kilowatt demand meter.

(4) The customer's power factor shall be determined from the registrations of suitable instruments, permanently installed, or by periodic tests at the option of the Company.

PAYMENT OF BILLS:

Bills are rendered net and payment is due within ten days from date bill is rendered.

Approval Issued: November 1, 1977
Effective: November 1, 1977
SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Rosemead, California 91770

Schedule No. TOU-8

GENERAL SERVICE — LARGE

APPLICABILITY
Applicable to three-phase general service, including lighting and power, supplied directly from lines of transmission voltage, or where the Company’s operating convenience service is supplied from lines of distribution voltage

This schedule is applicable for all customers of record on August 23, 1977, served on Schedule No. A-11 and thereafter is applicable to all customers whose monthly maximum demand exceeds 5,000 kW for any three months during the preceding 12 months. Any customer whose monthly maximum demand has fallen below 4,500 kW for 12 consecutive months may elect to take service on any other applicable schedule.

TERRITORY
Within the entire territory served, excluding Santa Catalina Island.

RATES

Customer Charge: $1,075.00

Demand Charge (to be added to Customer Charge):
- All kW of on-peak billing demand, per kW: $5.05
- All kW of mid-peak billing demand, per kW: $0.65
- All kW of off-peak billing demand, per kW: No Charge

Energy Charge (to be added to Demand Charge):
- All on-peak kWh, per kWh: 0.530c
- All mid-peak kWh, per kWh: 0.380c
- All off-peak kWh, per kWh: 0.230c

Minimum Charge:
The monthly minimum charge shall be the sum of the monthly Customer and Demand Charges. The monthly Demand Charge shall be not less than the charge for 75% of the maximum on-peak demand established during the preceding 11 months.

Daily time periods will be based on Pacific Standard Time and are defined as follows:

On-peak:
- 12:00 noon to 6:00 p.m. summer weekdays except holidays
- 5:00 p.m. to 10:00 p.m. winter weekdays except holidays

Mid-peak:
- 8:00 a.m. to 12:00 noon and 6:00 p.m. to 10:00 p.m. summer weekdays except holidays
- 8:00 a.m. to 5:00 p.m. winter weekdays except holidays

Off-peak:
- All other hours.


For initial implementation of this schedule by the Company, winter shall consist of the billing periods for the six regularly scheduled monthly billings beginning with the first regularly scheduled billing ending after November 14, 1977. Thereafter, regularly scheduled monthly billings shall include six summer billing periods followed by six winter billing periods. In no event will winter include scheduled billing periods ending after May 31 of any year.

(Continued)
SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Rosemead, California 91770

Schedule No. TOU-8
GENERAL SERVICE — LARGE

(Continued)

SPECIAL CONDITIONS

1. Voltage: Service will be supplied at one standard voltage.

2. Maximum Demand: Maximum demand shall be established for the daily on-peak, mid-peak, and off-peak periods. The maximum demand for each period shall be the measured maximum average kilowat input indicated or recorded by instruments to be supplied by the Company, during any 15-minute measured interval, but not less than the diversified resistance welder load computed in accordance with the section designated Welder Service in Rule No. 2. Where the demand is intermittent or subject to violent fluctuations, a 5-minute interval may be used.

3. Billing Demand: Separate billing demands for the on-peak, mid-peak, and off-peak daily time periods shall be established for each monthly billing period. The billing demand for each daily time period shall be the maximum demand for that daily time period occurring during the respective monthly billing period.

4. Voltage Discount: The charges before adjustments will be reduced by 1% for service delivered and metered at a nominal voltage of 2300 volts and by 2% for service delivered and metered at a nominal voltage of 60,000 volts or over.

5. Power Factor Adjustment: The charges will be adjusted each month for reactive demand. The charges will be increased by 20 cents per kilowat of maximum reactive demand imposed on the Company by excess of 20% of the maximum number of kilowat.

The maximum reactive demand shall be the highest measured maximum average kilowat demand indicated or recorded by metering to be supplied by the Company during any 15-minute measured interval in a month. The kilowat shall be determined in the nearest unit. A device shall be installed on each kilowat meter to prevent reverse operation of the meter.

6. Temporary Discontinuance of Service: Where the use of energy is seasonal or intermittent, no adjustment will be made for a temporary discontinuance of service. Any customer prior to resuming service within twelve months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

7. Contracts: An initial three-year facilities contract may be required where applicant requires new or added serving capacity exceeding 2,000 kVA.

8. Energy Cost Adjustment: The rates above are subject to adjustment as provided for in Part G of the Preliminary Statement. The applicable energy cost adjustment billing factors and fuel collection balance adjustment billing factor set forth thereon will be applied to all kWh billed under this schedule.

9. Tax Change Adjustment: The rates above are subject to adjustment as provided for in Part I of the Preliminary Statement. The applicable tax change adjustment billing factors set forth thereon will be applied to kWh billed under this schedule.

10. Conservation Load Management Adjustment: The rates above are subject to adjustment as provided for in Part J of the Preliminary Statement. The applicable conservation load management adjustment billing factors set forth thereon will be applied to kWh billed under this schedule.


Advised

Edward A. Meers, Jr.

Dec. 27, 1978

Vice President

Effective

January 1, 1979

Resolution No.
TIME OF DAY PRICING

The following data cards (numbers 32, 33, 34, and 35) are used to designate when the charges for purchased electrical energy are being made at the peak rate, the mid-peak rate, or at the off-peak rate.

Choose 0: if the demand is in an off-peak period.
Choose 1: if the demand is in a mid-peak period.
Choose 2: if the demand is at the peak period.

TYPICAL WORK DAY DURING THE SUMMER MONTHS

Enter your choice of the rate charges for the demand of each hour.

ENTER IN CARD 32:
Column:
1: 0100
2: 0200
3: 0300
4: 0400
5: 0500
6: 0600
7: 0700
8: 0800
9: 0900
10: 1000
11: 1100
12: 1200
13: 1300
14: 1400
15: 1500
16: 1600
17: 1700
18: 1800
19: 1900
20: 2000
21: 2100
22: 2200
23: 2300
24: 2400

Variable name: LRATE (IHR, KYRHLF, Nowork)
IHR = 1, 24; (Hours - 0100 thru 2400)
KYRHLF = 1; (Summer months)
Nowork = 1; (Work day)

Data card sample on page 102.
TYPICAL WORK DAY DURING THE WINTER MONTHS

Enter your choice of the rate charges for the demand of each hour.

ENTER IN CARD 33:
Column:
1: 0100
2: 0200
3: 0300
4: 0400
5: 0500
6: 0600
7: 0700
8: 0800
9: 0900
10: 1000
11: 1100
12: 1200
13: 1300
14: 1400
15: 1500
16: 1600
17: 1700
18: 1800
19: 1900
20: 2000
21: 2100
22: 2200
23: 2300
24: 2400

Variable name: LRATE (IHR, KYRHLF, Nowork)
IHR = 1, 24; (Hours = 0100 thru 2400)
KYRHLF = 2; (Winter months)
Nowork = 1; (Work day)

Data card sample on page 102.
TYPICAL NON-WORK DAY DURING THE SUMMER MONTHS

Enter your choice of the rate charges for the demand of each hour.

ENTER IN CARD 34:

<table>
<thead>
<tr>
<th>Column</th>
<th>Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0100</td>
</tr>
<tr>
<td>2</td>
<td>0200</td>
</tr>
<tr>
<td>3</td>
<td>0300</td>
</tr>
<tr>
<td>4</td>
<td>0400</td>
</tr>
<tr>
<td>5</td>
<td>0500</td>
</tr>
<tr>
<td>6</td>
<td>0600</td>
</tr>
<tr>
<td>7</td>
<td>0700</td>
</tr>
<tr>
<td>8</td>
<td>0800</td>
</tr>
<tr>
<td>9</td>
<td>0900</td>
</tr>
<tr>
<td>10</td>
<td>1000</td>
</tr>
<tr>
<td>11</td>
<td>1100</td>
</tr>
<tr>
<td>12</td>
<td>1200</td>
</tr>
<tr>
<td>13</td>
<td>1300</td>
</tr>
<tr>
<td>14</td>
<td>1400</td>
</tr>
<tr>
<td>15</td>
<td>1500</td>
</tr>
<tr>
<td>16</td>
<td>1600</td>
</tr>
<tr>
<td>17</td>
<td>1700</td>
</tr>
<tr>
<td>18</td>
<td>1800</td>
</tr>
<tr>
<td>19</td>
<td>1900</td>
</tr>
<tr>
<td>20</td>
<td>2000</td>
</tr>
<tr>
<td>21</td>
<td>2100</td>
</tr>
<tr>
<td>22</td>
<td>2200</td>
</tr>
<tr>
<td>23</td>
<td>2300</td>
</tr>
<tr>
<td>24</td>
<td>2400</td>
</tr>
</tbody>
</table>

Variable name: LRATE (IHR, KYRHLF, Nowork)
IHR = 1, 24; (Hours - 0100 thru 2400)
KRYHRL = 1; (Summer months)
Nowork = 2; (Non-work day)

Data card sample on page 103.
TYPICAL NON-WORK DAY DURING THE WINTER MONTHS

Enter your choice of the rate charges for the demand of each hour.

ENTER IN CARD 35:

Column:
1: 0100
2: 0200
3: 0300
4: 0400
5: 0500
6: 0600
7: 0700
8: 0800
9: 0900
10: 1000
11: 1100
12: 1200
13: 1300
14: 1400
15: 1500
16: 1600
17: 1700
18: 1800
19: 1900
20: 2000
21: 2100
22: 2200
23: 2300
24: 2400

Variable name: LRATE (IHR, KYRHLF, Nowork)
IHR = 1, 24; (Hours - 0100 thru 2400)
KYRHLF = 2; (Winter months)
Nowork = 2; (Non-work day)

Data card sample on page 103.
ENTER IN CARD 36:

The number of days per month.

Columns: 1 thru 6: January
7 thru 12: February
13 thru 18: March
19 thru 24: April
25 thru 30: May
31 thru 36: June
37 thru 42: July
43 thru 48: August
49 thru 54: September
55 thru 60: October
61 thru 66: November
67 thru 72: December

Variable name: PERMO (month)

Month = 1, 12; (January thru December)

Data card sample on page 104.

THE CURRENT PRICES OF FUEL, ELECTRICITY, OPERATING, AND MAINTENANCE COSTS

ENTER IN CARD 37:

| VARIABLE NAME | Columns: | the fuel cost for the gas turbine; $/MBTU*.
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>GTFLC</td>
<td>1 thru 10:</td>
<td>This will normally be a premium fuel; either #2 fuel oil or natural gas.</td>
</tr>
<tr>
<td>DSSLFC</td>
<td>11 thru 20:</td>
<td>the fuel cost for the diesel engine, $/MBTU. This will normally be a premium fuel, either #2 fuel oil or natural gas.</td>
</tr>
<tr>
<td>STTFLC</td>
<td>21 thru 30:</td>
<td>the fuel cost for the steam turbine, $/MBTU.</td>
</tr>
<tr>
<td>BLRFLC</td>
<td>31 thru 40:</td>
<td>the fuel cost for the auxiliary fired boiler, $/MBTU.</td>
</tr>
</tbody>
</table>

* NOTE: MBTU = million BTU.

Data card sample on page 105.
For specific information relating to the operating and maintenance costs, refer to the table and figures on pages 59 thru 65.

ENTER IN CARD 38:

<table>
<thead>
<tr>
<th>VARIABLE</th>
<th>NAME</th>
</tr>
</thead>
<tbody>
<tr>
<td>Columns:</td>
<td></td>
</tr>
<tr>
<td>1 thru 10:</td>
<td>the O&amp;M cost for the gas turbine as a peaking unit; $/MWH*.</td>
</tr>
<tr>
<td>11 thru 20:</td>
<td>the O&amp;M cost for the gas turbine as a cogenerating unit; $/MWH.</td>
</tr>
<tr>
<td>21 thru 30:</td>
<td>the O&amp;M cost for the diesel engine as a peaking unit; $/MWH.</td>
</tr>
<tr>
<td>31 thru 40:</td>
<td>the O&amp;M cost for the diesel engine as a cogenerating unit; $/MWH.</td>
</tr>
<tr>
<td>41 thru 50:</td>
<td>the O&amp;M cost for the steam turbine as a peaking unit; $/MWH.</td>
</tr>
<tr>
<td>51 thru 60:</td>
<td>the O&amp;M cost for the steam turbine as a cogenerating unit; $/MWH.</td>
</tr>
<tr>
<td>61 thru 70:</td>
<td>the O&amp;M cost for the auxiliary fired boiler; $/KLB* steam.</td>
</tr>
<tr>
<td>71 thru 80:</td>
<td>the O&amp;M cost for the waste heat recovery boiler; $/KLB steam.</td>
</tr>
</tbody>
</table>

* NOTE: MWH = Megawatt hours.
KLB = Kilo pounds (1000 pounds).

Data card sample on page 106.

ENTER IN CARD 39:

<table>
<thead>
<tr>
<th>VARIABLE</th>
<th>NAME</th>
</tr>
</thead>
<tbody>
<tr>
<td>Columns:</td>
<td></td>
</tr>
<tr>
<td>1 thru 10:</td>
<td>the fixed O&amp;M cost per month for the gas turbine; $/month.</td>
</tr>
<tr>
<td>11 thru 20:</td>
<td>the fixed O&amp;M cost per month for the diesel engine; $/month.</td>
</tr>
<tr>
<td>21 thru 30:</td>
<td>the fixed O&amp;M cost per month for the steam turbine; $/month.</td>
</tr>
<tr>
<td>31 thru 40:</td>
<td>the fixed O&amp;M cost per month for the auxiliary fired boiler; $/month.</td>
</tr>
<tr>
<td>41 thru 50:</td>
<td>the O&amp;M cost per KLB* of steam generated by the high pressure boiler; $/KLB.</td>
</tr>
</tbody>
</table>

* NOTE: KLB = Kilo pounds (1000 pounds).

Data card sample on page 106.
<table>
<thead>
<tr>
<th>Potential Contributor to O&amp;M Costs</th>
<th>Estimating Procedure or Figure</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>A. Steam Turbine Cogeneration Plants, Coal-Fired</strong></td>
<td></td>
</tr>
<tr>
<td>Central Receiving and Handling Facility</td>
<td>Figure 11&lt;sup&gt;a&lt;/sup&gt;</td>
</tr>
<tr>
<td>Hauling, Receiving Facility - Generating Plant (if not co-located)</td>
<td>Figure 12&lt;sup&gt;a&lt;/sup&gt;</td>
</tr>
<tr>
<td>Steam Generating Facility</td>
<td>Figure 13&lt;sup&gt;a&lt;/sup&gt;</td>
</tr>
<tr>
<td>Air Pollution Control System</td>
<td>Figure 14&lt;sup&gt;a&lt;/sup&gt;</td>
</tr>
<tr>
<td>Electrical Generating Facility</td>
<td></td>
</tr>
<tr>
<td>Hauling of Waste to Temporary Storage (if required)</td>
<td></td>
</tr>
<tr>
<td>Waste Disposal (annual cost, knowing average tons per hour throughout year)</td>
<td></td>
</tr>
<tr>
<td><strong>B. Steam Turbine Cogeneration Plants, Oil- or Natural Gas-Fired</strong></td>
<td></td>
</tr>
<tr>
<td>Steam Generating Facility</td>
<td>$1.10/10^3$ lb of steam&lt;sup&gt;c&lt;/sup&gt; (for natural gas or distillate oil)</td>
</tr>
<tr>
<td></td>
<td>$1.50/10^3$ lb of steam&lt;sup&gt;c&lt;/sup&gt; (for residual oil)</td>
</tr>
<tr>
<td>Electrical Generating Facility</td>
<td>(2.5% x capital)/yr&lt;sup&gt;b&lt;/sup&gt;, where Figure 7 shows capital investment</td>
</tr>
<tr>
<td>Air Pollution Control System (only if designed to use high sulfur fuel)</td>
<td>Figure 14&lt;sup&gt;a&lt;/sup&gt;</td>
</tr>
<tr>
<td><strong>C. Combustion Turbine/Generator Sets With Exhaust Heat Boilers</strong></td>
<td></td>
</tr>
<tr>
<td>Turbine/Generator Set</td>
<td>4.0 mils/kW-hr&lt;sup&gt;d&lt;/sup&gt; for units operating on “continuous” duty, and for units ≤ 2 MWe on peaking duty</td>
</tr>
<tr>
<td></td>
<td>7.0 mils/kW-hr&lt;sup&gt;d&lt;/sup&gt; for units &gt; 2 MWe on peaking duty</td>
</tr>
<tr>
<td>Exhaust Heat Boiler</td>
<td>$1.00/10^3$ lb of steam&lt;sup&gt;c&lt;/sup&gt;</td>
</tr>
</tbody>
</table>

<sup>a</sup> continued
Table 1. Continued

<table>
<thead>
<tr>
<th>Potential Contributor to O&amp;M Costs</th>
<th>Estimating Procedure or Figure</th>
</tr>
</thead>
<tbody>
<tr>
<td>D. Diesel/Generator Sets With Exhaust Heat Boiler</td>
<td></td>
</tr>
<tr>
<td>Diesel/Generator Set</td>
<td>13 mils/kW-hr(^g)</td>
</tr>
<tr>
<td>Exhaust Heat Boiler</td>
<td>$1.00/10^3$ lb of steam(^f)</td>
</tr>
</tbody>
</table>

**NOTE:** For conventional steam generating facilities, use the appropriate parts of lists A and B above.

\(^a\)Reference 2.
\(^b\)Reference 1.
\(^c\)Based on data from Long Beach Naval Shipyard and Sewell’s Point Naval Complex compiled by CEL.
\(^d\)Based on correspondence with Garrett Airesearch and Pacific Gas and Electric personnel. Includes costs for major overhauls.
\(^e\)Based on data from San Diego Gas and Electric.
\(^f\)CEL estimate.
\(^g\)Based on Reference 3.

The fuel cost contribution to generated power is

\[ FPC = (HR_{EFF})(CF)(1/10^3) \]

where

- \( FPC \) = fuel contribution to power costs, mils/kW-hr
- \( CF \) = cost of fuel, $/million Btu

For power from the cogeneration system to be economically attractive to the Navy, the fuel cost contribution must be sufficiently less than the cost of purchased power to allow for capital recovery and O&M. For the power to be economically attractive to a utility company, the fuel cost contribution must compare favorably with costs they experience or anticipate in their system.
TYPICAL MID-1978 COSTS, all overhead included

Does not include: hauling costs from central receiving and handling facility to powerplant, if separate locations required

Correlation of coal handling capacity with steam production capacity:

$$\hat{C} = \frac{S}{\ln^{BLR}(HV)(2000)}$$

where

$\hat{C}$ = Coal handling capacity, tons/hr

$S$ = Design capacity of boiler facilities, Btu/hr

$\eta_{BLR}$ = Boiler efficiency

$HV$ = Coal heating value, Btu/lb

Figure 11. Operating and maintenance costs for central receiving and coal-handling facilities with stockpile.
Figure 12. Operating and maintenance costs for short distance hauling of coal or solid waste.
TYPICAL MID-1978 COSTS, all overhead included.

Assumptions:
- Plant contains four quarter-capacity boilers.
- Plant operates at 33% load factor.

Figure 13. Operating and maintenance costs for coal-fired steam boilers.
TYPICAL MID-1978 COSTS, all overhead included

Type of System: Double alkali flue gas desulfurization plus baghouse particulate removal, achieving 1.2 lb S and 0.1 lb flyash per 10^6 Btu fuel input

Assumptions: Plant operates at 40% excess air
Flyash = 40% wtl x (coal ash + 4% unburned carbon)
Ash = 19.5 - 23% wt of coal
Plant operates at 33% load factor

Figure 14. Operating and maintenance costs for air pollution control of coal-fired generating plants.
REFERENCES


The rate structures of the utility companies vary as to geological location.

Demand pricing is generally used by the eastern states and time of day pricing is generally used by the western states. Contact the utility company to determine the rate structure applicable to this study.

This version of the CELCAP program is set up for the demand pricing rate structure. The instructions that follow for data cards 40 and 41 are for the demand pricing rate structure only. If the area of study utilizes the time of day rate structure, the program will have to be modified. A version of the time of day rate structure program is available at the Civil Engineering Laboratory (refer to page i). The instructions for data cards 40 and 41 for the time of day rate structure are on page 70.

Refer to pages 67 thru 69 for a typical example of the demand rate schedule from Newport Electric Corporation, Newport, RI.

**ENTER IN CARD 40:**

<table>
<thead>
<tr>
<th>VARIABLE</th>
<th>NAME</th>
</tr>
</thead>
<tbody>
<tr>
<td>Columns:</td>
<td></td>
</tr>
<tr>
<td>1 thru 10:</td>
<td>the customer charge per meter/per month, $.</td>
</tr>
<tr>
<td>11 thru 20:</td>
<td>the demand charge for the first 5000 KW* of the billing demand or less per month; $.</td>
</tr>
<tr>
<td>21 thru 30:</td>
<td>the demand charge for all of the additional KW of the billing demand, $/KW.</td>
</tr>
<tr>
<td>31 thru 40:</td>
<td>the energy charge for the first 340 hours of use of the billing demand per month; cents/KWH*.</td>
</tr>
<tr>
<td>41 thru 50:</td>
<td>the energy charge for all of the additional KWH of use per month; cents/KWH*.</td>
</tr>
<tr>
<td>51 thru 60:</td>
<td>the fuel adjustment charge; $/KWH.</td>
</tr>
</tbody>
</table>

* NOTE: KW = Kilowatt.
  KWH = Kilowatt hours.

Data card sample on page 107

**ENTER IN CARD 41:**

<table>
<thead>
<tr>
<th>VARIABLE</th>
<th>NAME</th>
</tr>
</thead>
<tbody>
<tr>
<td>Columns:</td>
<td></td>
</tr>
<tr>
<td>1 thru 10:</td>
<td>the billing demand KW, it is 75% of the maximum billing demand established by the customer during any of the immediately preceding eleven months.</td>
</tr>
</tbody>
</table>

If the demand pricing rate structure is being used: TURN TO PAGE 73.

Data card sample on page 107.
WHOLESALE POWER SERVICE

AVAILABILITY:

Service is available hereunder for any power purchases, but not for resale, to any customer who will enter into a contract, satisfactory to Company, to purchase all of its requirements of electric energy for power purposes from the Company for a period of not less than five (5) years provided Company has adequate generating and/or transmission facilities available to serve such customers over and above the requirements of existing customers. Service shall be supplied through a single point of delivery and one metered supply unless for the sole convenience of Company more than one delivery point or one metered supply will be provided. Electric energy for the lighting purposes of customer may also be purchased hereunder provided customer supplies and maintains the necessary transformers thereafter.

CHARACTER OF SERVICE:

Service supplied hereunder shall be three phase, 60 cycle electric energy at a nominal voltage of 23,000 volts, or higher.

RATE:

Demand Charge:

First 5,000 Kw of billing demand or less per month - $16,650

All additional kw of billing demand - 2.30 per kw

Energy Charges:

First 340 hours use of billing demand per month - 3.07¢ per kwh

All additional kwh used per month - 2.79¢ per kwh

DETERMINATION OF BILLING DEMAND:

The billing demand in kilowatts for each month shall be the greater of (a) the maximum demand adjusted for power factor each month, (b) 75% of the maximum billing demand established by customer during any of the immediately preceding eleven months, (c) 50% of the maximum billing demand established by customer during the life of the contract, or (d) 5,000 kilowatts.
POWER FACTOR ADJUSTMENT:

For billing demand purposes, when the power factor of customer as measured hereunder is above 80% lagging and below 90% lagging no adjustment of the maximum demand as measured in kilowatts for each billing month shall be made. When the power factor of customer as measured hereunder shall in any month fall below 80% lagging, then the demand measured hereunder shall be adjusted by multiplying by 90% and dividing by the power factor expressed as a percentage. When the power factor of customer as measured hereunder shall in any month rise above 90% lagging, then the demand measured hereunder shall be adjusted by multiplying by 90% and dividing by the power factor expressed as a percentage. For the purposes of the faster adjustment, the power factor shall in no event be considered as greater than unity.

MINIMUM CHARGE:

The monthly minimum charge for service hereunder shall be the demand charge plus the energy charge for 170 hours use of the billing demand of such month, subject to Fuel, Primary Metering and Transformer Ownership adjustments.

FUEL ADJUSTMENT CLAUSE:

All energy delivered hereunder, including the amount in the minimum charge, shall be subject to the provisions of the Company's Standard Fuel Adjustment Clause.

PRIMARY METERING:

If the electric energy delivered to customer is measured at the line voltage, not less than 23,000 volts, at which it is transmitted to the point of delivery hereunder, there will be credited against the amount determined under the preceding provisions two and one-half percent (2-1/2%) of the demand charge and energy charge for such month.

TRANSFORMER OWNERSHIP:

If customer utilizes electric energy at the line voltage, not less than 23,000 volts, at which it is transmitted to the point of delivery hereunder or if customer provides all transformers which may be required to reduce the line voltage to the level at which the electric energy is to be used by customer, there will be credited against the amount determined under the preceding provisions twelve cents ($0.12) for each kilowatt of billing demand for such month.
TERMS AND CONDITIONS:

(1) Service hereunder shall be subject to the Company's Terms and Conditions in effect from time to time and not inconsistent with any specific provisions of this rate schedule.

(2) The term "year" shall mean each twelve-month period beginning after the date of the first delivery of electric energy to customer under this rate schedule.

(3) The term "demand" shall mean customer's maximum average rate of taking electric energy hereunder during any fifteen-minute period during the billing month as measured by a standard kilowatt demand meter.

(4) The customer's power factor shall be determined from the registrations of suitable instruments, permanently installed, or by periodic tests at the option of the Company.

PAYMENT OF BILLS:

Bills are rendered net and payment is due within ten days from date bill is rendered.

Approval Issued: November 1, 1977
Effective: November 1, 1977
TIME OF DAY RATE STRUCTURE

Refer to pages 71 and 72 for a typical example of the time of day rate schedule from the Southern California Edison Company, Rosemead, CA.

ENTER IN CARD 40:

<table>
<thead>
<tr>
<th>Columns</th>
<th>Description</th>
<th>Variable</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 thru 10</td>
<td>the customer charge per meter/per month, $</td>
<td>CHMTR</td>
</tr>
<tr>
<td>11 thru 20</td>
<td>the demand charge of the on-peak KW; $/KW</td>
<td>DCHPK</td>
</tr>
<tr>
<td>21 thru 30</td>
<td>the demand charge of the mid-peak KW; $/KW</td>
<td>DCHMID</td>
</tr>
<tr>
<td>31 thru 40</td>
<td>the demand charge of the off-peak KW; $/KW</td>
<td>DCHOFF</td>
</tr>
<tr>
<td>41 thru 50</td>
<td>the energy charge of the on-peak KWH; $/KWH</td>
<td>ECHPK</td>
</tr>
<tr>
<td>51 thru 60</td>
<td>the energy charge of the mid-peak KWH; $/KWH</td>
<td>ECHMID</td>
</tr>
<tr>
<td>61 thru 70</td>
<td>the energy charge of the off-peak KWH; $/KWH</td>
<td>ECHOFF</td>
</tr>
<tr>
<td>71 thru 80</td>
<td>the fuel adjustment charge; $/KWH</td>
<td>FLADJ</td>
</tr>
</tbody>
</table>

VARIABLE ENTER IN CARD 41:

<table>
<thead>
<tr>
<th>Columns</th>
<th>Description</th>
<th>Variable</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 thru 10</td>
<td>the on-peak demand; KW</td>
<td>DMDPK</td>
</tr>
<tr>
<td>11 thru 20</td>
<td>the mid-peak demand; KW</td>
<td>DMDMID</td>
</tr>
<tr>
<td>21 thru 30</td>
<td>the off-peak demand; KW</td>
<td>DMDOFF</td>
</tr>
</tbody>
</table>

Assumptions for on-peak, mid-peak, and off-peak demand levels:

1. Five engines with the combined capacity of 515 + 500 + 7,500 + 5,000 = 18,565 KW. Firm capacity (calculated assuming the two largest engines are down) = 515 + 500 + 5,000 = 6,015 KW.

*2. Un-peak demand = 20,000 KW - 6,015 KW = 13,985 KW. (Based on load peak = 20,000 KW during on-peak hours.)

**3. Mid-peak demand = 17,000 KW - 6,015 KW = 10,985 KW. (Based on load peak = 17,000 KW during mid-peak hours.)

***4. Off-peak demand = 15,000 KW - 6,015 KW = 8,985 KW. (Based on load peak = 15,000 KW during off peak hours.)

Data card sample on page 108.
Schedule No. TOU-8

GENERAL SERVICE—LARGE

APPLICABILITY
Applicable to three-phase general service, including lighting and power, supplied directly from lines of transmission voltage or where the Company's operating convenience service is supplied from lines of distribution voltage.

This schedule is applicable for all customers of record on August 23, 1977, served on Schedule No. A-1 and thereafter is applicable to all customers whose monthly maximum demand exceeds 3,000 kW for any three months during the preceding 12 months. Any customer whose monthly maximum demand has fallen below 3,000 kW for 12 consecutive months may elect to take service on any other applicable schedule.

TERRITORY
Within the entire territory served, excluding Santa Catalina Island.

RATES

<table>
<thead>
<tr>
<th>Description</th>
<th>Per Hour</th>
<th>Per Month</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Charge:</td>
<td>$1,075.00</td>
<td></td>
</tr>
<tr>
<td>Demand Charge (to be added to Customer Charge):</td>
<td></td>
<td></td>
</tr>
<tr>
<td>All kW of on-peak billing demand, per kW</td>
<td>$ 5.03</td>
<td></td>
</tr>
<tr>
<td>Plus all kW of mid-peak billing demand, per kW</td>
<td>0.65</td>
<td></td>
</tr>
<tr>
<td>Plus all kW of off-peak billing demand, per kW</td>
<td>No Charge</td>
<td></td>
</tr>
<tr>
<td>Energy Charge (to be added to Demand Charge):</td>
<td></td>
<td></td>
</tr>
<tr>
<td>All on-peak kWh, per kWh</td>
<td>0.5300</td>
<td></td>
</tr>
<tr>
<td>Plus all mid-peak kWh, per kWh</td>
<td>0.3800</td>
<td></td>
</tr>
<tr>
<td>Plus all off-peak kWh, per kWh</td>
<td>0.2300</td>
<td></td>
</tr>
<tr>
<td>Minimum Charge:</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| The monthly minimum charge shall be the sum of the monthly Customer and Demand Charges. The monthly Demand Charge shall be not less than the charge for 25% of the maximum on-peak demand established during the preceding 11 months. Daily time periods will be based on Pacific Standard Time and are defined as follows: On-peak: 12:00 noon to 6:00 p.m. summer weekdays except holidays 5:00 p.m. to 10:00 p.m. winter weekdays except holidays Mid-peak: 8:00 a.m. to 12:00 noon and 6:00 p.m. to 10:00 p.m. summer weekdays except holidays 8:00 a.m. to 5:00 p.m. winter weekdays except holidays Off-peak: All other hours. Off-peak holidays are New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas. For initial implementation of this schedule by the Company, winter shall consist of the billing periods for the six regularly scheduled monthly billings beginning with the first regularly scheduled billing ending after November 14, 1977. Thereafter, regularly scheduled monthly billings shall include six summer billing periods followed by six winter billing periods. In no event will winter include scheduled billing periods ending after May 31 of any year.

(Continued)
SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Rosemead, California 91770

Schedule No. TOU-B

GENERAL SERVICE — LARGE

(Continued)

SPECIAL CONDITIONS

1. Voltage: Service will be supplied at one standard voltage.

2. Maximum Demand: Maximum demand shall be established for the daily on-peak, mid-peak, and off-peak periods. The maximum demand for each period shall be the measured maximum average kilowatt input indicated or recorded by instruments to be supplied by the Company, during any 15-minute metered interval, but not less than the measured resistance welder load computed in accordance with the section designated Welder Service in Rule No. 2, Where the demand is intermittent or subject to violent fluctuations, a 5-minute interval may be used.

3. Billing Demand: Separate billing demands for the on-peak, mid-peak, and off-peak daily time periods shall be established for each monthly billing period. The billing demand for each daily time period shall be the maximum demand for that daily time period occurring during the respective monthly billing period.

4. Voltage Discount: The charges before adjustments will be reduced by 1% for service delivered and metered at a nominal voltage of 12,000 volts, and by 2% for service delivered and metered at a nominal voltage of 66,000 volts or over.

5. Power Factor Adjustment: The charges will be adjusted each month for reactive demand. The charges will be increased by 2% per kilowatt of maximum reactive demand imposed on the Company in excess of 20% of the maximum number of kilowatts.

The maximum reactive demand shall be the highest measured maximum average kilowatt demand indicated or recorded by metering to be supplied by the Company during any 15-minute metered interval in the month. The kilowatts shall be determined to the nearest unit. A device will be installed on each kilowatt meter to prevent reverse operation of the meter.

6. Temporary Discontinuance of Service: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within twelve months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

7. Contracts: An initial three-year facilities contract may be required where applicant requires new or added serving capacity exceeding 2,000 kVA.

8. Energy Cost Adjustment: The rates above are subject to adjustment as provided for in Part C of the Preliminary Statement. The applicable energy cost adjustment billing factors and fuel collection balance adjustment billing factor set forth therein will be applied to all kWh billed under this schedule.

9. Tax Change Adjustment: The rates above are subject to adjustment as provided for in Part I of the Preliminary Statement. The applicable tax change adjustment billing factors set forth therein will be applied to kWh billed under this schedule.

10. Conservation Load Management Adjustment: The rates above are subject to adjustment as provided for in Part J of the Preliminary Statement. The applicable conservation load management adjustment billing factors set forth therein will be applied to kWh billed under this schedule.

(To be marked by witness)
Advisory Letter No. 479-E

Issued by
Edward A. Myers, Jr.

Date Filed
December 27, 1978

Effective
January 1, 1979

Resolution No.
ENTER IN CARD 42:

Columns: 1 thru 10: the ratio of sale price to purchase price of electricity. Assumes excess electricity generated can be sold back to the utility company, and utility will reimburse for energy, but not demand and meter charges.

Data card sample on page 109.
For specific information on the life cycle cost analysis, refer to the Department of the Navy letter dated 27 July 1978, and related figures on pages 76 thru 79.

ENTER IN CARD 43:

Columns: 1 thru 5: the year for which the present value costs NOWYR will be computed.
6 thru 10: the year the installation will be completed. INSTYR
11 thru 15: the year the escalation rate will change JYRCHN from short-term to long-term. This is normally 25 years. Refer to figures on page 80.
16 thru 20: the number of years of the economic life. LIFE Refer to figures on page 81.

Data card sample on page 110.

For specific information on the short-term escalation rate, refer to item 9 on page 78.

For specific information on the long-term differential escalation rate, refer to item 10 on page 79.

ENTER IN CARD 44:

Columns: 1 thru 10: the short-term escalation rate of the fuel FESTGT price for the gas turbine.
11 thru 20: the long-term differential escalation rate FELTGT of the fuel price for the gas turbine.
21 thru 30: the short-term escalation rate of the fuel FESTDS price for the diesel engine.
31 thru 40: the long-term differential escalation rate FELTDS of the fuel price for the diesel engine.
41 thru 50: the short-term escalation rate of the fuel FESTST price for the steam turbine.
51 thru 60: the long-term differential escalation rate FELTST of the fuel price for the steam turbine.
61 thru 70: the short-term escalation rate of the fuel FESTBL price for the auxiliary fired boiler.
71 thru 80: the long-term differential escalation rate FELTBL of the fuel price for the auxiliary fired boiler.

Data card sample on page 111.
ENTER IN CARD 45:

Columns:  
1 thru 10: the short-term differential escalation rate for operating and maintenance.  
11 thru 20: the long-term differential escalation rate for operating and maintenance.  
21 thru 30: the short-term escalation rate for electricity.  
31 thru 40: the long-term differential escalation rate for electricity.  
41 thru 50: the discount factor. For Navy application, it is mandated as 10% (0.10).  

Data card sample on page 111.
1. The conservation of energy continues to be an important national goal, one strongly supported by the Navy. This support is evidenced by the allocation of significant resources for a dedicated military construction program created to reduce energy consumption at Naval shore activities through the retrofit of existing facilities. $53 million, $55 million, and $50 million have been identified for this ECIP program in fiscal years 81, 82, and 83 respectively.

2. The ECIP program can make a real contribution toward meeting this national goal, but only through the wholehearted support of the Major Claimants in the development of meaningful projects for the program. Projects funded under this program are those which return the maximum reduction in energy consumption for the dollar invested. The attention and imagination of the addressees in developing and submitting projects in support of this program is solicited. Since the projects will be funded under the dedicated program they will not decrease a Major Claimants' share of the regular MILCON.

3. Submission of projects in accordance with references (a) and (b) as expeditiously as possible is encouraged to insure funding consideration in the earliest programming cycle. Criteria for candidate ECIP projects is forwarded as enclosure (1).

Distribution:

SHDL
21A (Fleet Commanders in Chief)
A3 (Chief of Naval Operations)
A4A (Chief of Naval Material)
ENERGY CONSERVATION INVESTMENT PROGRAM (ECIP) CRITERIA

The ECIP shall include military construction projects which conserve energy and meet the following criteria:

1. ECIP projects must be cost-effective based on a savings-to-investment ratio greater than one utilizing a life cycle cost analysis.

2. Each project must have an energy savings-to-investment ratio of at least the following values for annual million BTUs (MBTUs) saved per $1000 of total investment: FY-80, 22; FY-81, 20; FY-82, 19; FY-83, 18; and FY-84, 17.

3. Projects are restricted to the retrofit of existing facilities. New construction and total replacement of facilities will not be included in the ECIP.

4. ECIP projects should combine similar work in various buildings with different category codes in order to reduce contract administration costs. An individual project may also combine dissimilar work of different construction trades. When a basewide ECIP project affects more than one claimant, the host activity or lead activity or public works center should prepare and sponsor the project.

5. Projects shall be supported with engineering calculations in sufficient detail to allow validation of energy savings. Most projects will also require supplementary sheets showing such calculations as changes in insulation "U" factors, heat loss rates, and kilowatt demand reductions.

6. Actual fuel heating value rates should be used when known. If not known, the following conversion factors will be used to permit standardized project evaluation comparisons:

- Distillate Fuel Oil .......... 130,700 BTU/gal
- Residual Fuel Oil .......... 150,000 BTU/gal
- Natural Gas ................. 1,031,000 BTU/1000 cu.ft.
- LPG, Propane, Butane ........ 95,500 BTU/gal
- Bituminous Coal ............. 24,500,000 BTU/Short Ton
- Purchased Steam ................ 1,390 BTU/lb
- Electrical Source Fuel ....... 11,600 BTU/kWh

ENCL (1) TO CNO SER 44/720848 OF 27 Jul 1978

Enclosure (1)
7. Boiler efficiencies should be included in the calculation of savings from reduced steam consumption. The resulting reduction in fuel input and boiler feedwater represent a real cost avoidance when steam consumption is reduced. The "as-consumed" cost of fuel and electricity shall be used in determining energy dollar savings. The energy costs, as reported by each activity in the monthly Defense Energy Information System (DEIS-II) report, are "as-consumed" costs. An 'Activity Rate or Cost Rate', which includes overhead and maintenance costs, should not be used for calculating savings. Such costs do not normally change with small percentage reductions in overall steam consumption.

8. When two or more energy projects are programmed for the same facility, the computation of energy savings must indicate which portions of the energy savings would be duplicative.

9. Energy, material, and labor prices should be escalated from current rates to those projected for 30 September of the fiscal year for which the project is submitted for funding. Unless more definitive future prices can be determined or predicted for an individual activity, the following rates are to be used for escalation:

<table>
<thead>
<tr>
<th></th>
<th>FY-79</th>
<th>FY-80</th>
<th>FY-81</th>
<th>FY-82</th>
<th>FY-83</th>
</tr>
</thead>
<tbody>
<tr>
<td>Design &amp; Construction</td>
<td>7.0%</td>
<td>6.5%</td>
<td>6.0%</td>
<td>6.0%</td>
<td>6.0%</td>
</tr>
<tr>
<td>Operations &amp;</td>
<td>6.4%</td>
<td>6.2%</td>
<td>5.6%</td>
<td>5.6%</td>
<td>5.6%</td>
</tr>
<tr>
<td>Maintenance</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal</td>
<td>10.0%</td>
<td>10.0%</td>
<td>10.0%</td>
<td>10.0%</td>
<td>10.0%</td>
</tr>
<tr>
<td>Fuel Oil</td>
<td>16.0%</td>
<td>16.0%</td>
<td>14.0%</td>
<td>14.0%</td>
<td>14.0%</td>
</tr>
<tr>
<td>Natural Gas &amp; LPG</td>
<td>15.0%</td>
<td>15.0%</td>
<td>14.0%</td>
<td>14.0%</td>
<td>14.0%</td>
</tr>
<tr>
<td>Electricity (KWH &amp; KW)</td>
<td>16.0%</td>
<td>16.0%</td>
<td>13.0%</td>
<td>13.0%</td>
<td>13.0%</td>
</tr>
</tbody>
</table>
10. The life cycle cost analysis used to determine the project’s savings-to-investment ratio shall utilize a base fiscal year commencing on 1 October following the project’s programmed year. The long-term differential escalation rates below are to be used for computing the present worth of recurring annual costs and benefits if more definitive data is not available at individual activities.

Operations & Maintenance ...... 0%  Natural Gas & LPG ................. 8%
Coal ..................... 5%  Electricity (KWH & KW) ............. 7%
Fuel Oil ................. 8%

11. The present worth factors for multiplication of recurring annual savings can be selected from the appropriate differential escalation rate column in the DISCOUNT FACTORS table on the next page.

12. Economic life is the period of time over which the life cycle benefits to be gained from a project may reasonably be expected to accrue. As such, the economic life may differ from its physical and technological life. The economic lives below may be used as guides, and ordinarily will not be exceeded.

<table>
<thead>
<tr>
<th>CATEGORY</th>
<th>ECONOMIC LIFE</th>
</tr>
</thead>
<tbody>
<tr>
<td>BUILDINGS (including insulation, solar screens, heat recovery systems, solar installations, etc.)</td>
<td>25 years</td>
</tr>
<tr>
<td>UTILITIES (plants and distribution systems)</td>
<td>25 years</td>
</tr>
<tr>
<td>ENERGY MONITORING &amp; CONTROL SYSTEMS</td>
<td>15 years</td>
</tr>
<tr>
<td>CONTROLS (thermostats, limit switches, ignition devices, clocks, photo cells, flow controls, sensors, etc. when these constitute the major end item of the project)</td>
<td>15 years</td>
</tr>
<tr>
<td>REFRIGERATION COMPRESSORS</td>
<td>15 years</td>
</tr>
</tbody>
</table>
SAMPLES OF
DATA CARD NUMBERS 1 THRU 45
### Data Card #1

**Control Modes**

**Variable Name:** MDLTR

### Data Card #2

**Reports**

**Variable Name:** IPRNT
Data Card #3
Information on the Auxiliary Fired Boiler
Variable Names: TBLRFO, TEVP, HLV, BLREF
Data Card #4
Total Number of Engines
Variable Names: NUMGT, NUMDSL, NUMSTT, NUBPST

14.7

Data Card #5
Ambient Pressure
Variable Name: PAMB
### Data Card #6
**Maximum Temperature Per Month**

**Variable Name:** TMAX (Month)

<table>
<thead>
<tr>
<th>Month</th>
<th>Temperature</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>480.6</td>
</tr>
<tr>
<td>2</td>
<td>481.2</td>
</tr>
<tr>
<td>3</td>
<td>489.0</td>
</tr>
<tr>
<td>4</td>
<td>497.8</td>
</tr>
<tr>
<td>5</td>
<td>506.9</td>
</tr>
<tr>
<td>6</td>
<td>516.5</td>
</tr>
<tr>
<td>7</td>
<td>523.0</td>
</tr>
<tr>
<td>8</td>
<td>521.0</td>
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<td>9</td>
<td>513.6</td>
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<tr>
<td>10</td>
<td>503.4</td>
</tr>
<tr>
<td>11</td>
<td>494.6</td>
</tr>
<tr>
<td>12</td>
<td>483.4</td>
</tr>
</tbody>
</table>

### Data Card #7
**Minimum Temperature Per Month**

**Variable Name:** TMIN (Month)

<table>
<thead>
<tr>
<th>Month</th>
<th>Temperature</th>
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</thead>
<tbody>
<tr>
<td>1</td>
<td>-84</td>
</tr>
</tbody>
</table>
Data Card #8
Design Conditions for the Gas Turbine
Variable Names: ED, QFD, AIRFLD, TAMBD, PAMB, HV

0. 0. 0. 0. 0. 0.
Data Card #10
The Heat Recovery Boiler for the Gas Turbine
Variable Names: STMPRE, STMTEP, STMENTH, FETEMP, FEENTH, EFFCTV, EFFNS
Data Card #11
Design Conditions for the Diesel Engine
Variable Names: ED, QFD, TEXHD, TEXHP, EDP

7301.7 760. 30. 734.4 1172.0 528. 30. 1.00

Data Card #12
Heat Recovery Boiler for the Diesel Engine
Variable Names: AIRFLD, TSTACK, STMPRE, STMTEP, STMENTH,
FETEMP, FEENTH, EFFCTV

-87-
Data Card #13
Auto Extraction Steam Turbine Data
Variable Names: PAMBD, WCD, WTD, TAMBD, EED, ED

0.857 13.1 36. 0.80 0.85 111700.

Data Card #14
Auto Extraction Steam Turbine Data
Variable Names: T3LIM, TPNCHD, TEXHD, T3FRC, EFFCTV, THROMAX

-88-
Data Card #15
Auto Extraction Steam Turbine Data
Variable Names: EXPO, T2D, T3D, WC

65000.  3000.  .710

Data Card #16
Auto Extraction Steam Turbine Data
Variable Names: STMV, BLDM, UA

-89-
Data Card #17

Back Pressure Steam Turbine Data

Variable Names: EED, QFD, EDP, QFP, T3FRC, T3LIM

1172.0  700.  750.  30.  274.4  36.
Electrical Load on a Typical Work Day Per Hour in January
Variable Name: ELLD (IMR, Month, Nowork)

<p>| | | | | | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
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</thead>
<tbody>
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<td>8796</td>
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Data Card #19

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<td>11110</td>
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<td>11910</td>
<td>11996</td>
<td>12020</td>
<td>12114</td>
<td>11997</td>
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</table>

Data Card #20
Electrical Load on a Typical Non-Work Day Per Hour in January.
Variable Name: ELLD (IHR, Month, Nowork)

<p>| | | | | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
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<th></th>
<th></th>
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<td>8572</td>
<td>8176</td>
<td>7947</td>
<td>7704</td>
<td>7651</td>
<td>7605</td>
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</tbody>
</table>

Data Card #22

<p>| | | | | | |</p>
<table>
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</thead>
<tbody>
<tr>
<td>8622</td>
<td>9117</td>
<td>9297</td>
<td>9502</td>
<td>9548</td>
<td>9655</td>
</tr>
</tbody>
</table>

Data Card #23
Data Card #24
Steam Load on a Typical Work Day Per Hour In January
Variable Name: STMLD (IHR, Month, Nowork)

<p>| | | | | | | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>120902.</td>
<td>124004.</td>
<td>126550.</td>
<td>128441.</td>
<td>130000.</td>
<td>134631.</td>
<td>136484.</td>
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Data Card #25

<p>| | | | | | | | |</p>
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<tr>
<th></th>
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<th></th>
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</thead>
<tbody>
<tr>
<td>133587.</td>
<td>129498.</td>
<td>124160.</td>
<td>120015.</td>
<td>115578.</td>
<td>114020.</td>
<td>114101.</td>
<td>114954.</td>
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</table>

Data Card #26
Steam Load on a Typical Non-Workday Per Hour in January
Variable Name: STMLD (IHR, Month, Nowork)

112069.  114766.  116930.  118625.  119637.  119630.  118625.  114766.

Data Card #28

108991.  102180.  95368.  95953.  85734.  84380.  84722.  85734.

Data Card #29
Data Card #31
Months the Rate Changes to Summer and Winter for Demand Pricing
Variable Names: SUMON1, SUMON2
Data Card #32 Demand Pricing
Rate Charges for the Demand of Each Hour on a Typical Work Day
During the Summer Months
Variable Names: LRATE (IHR, KYRHF, Nowork)
Data Card #34 Demand Pricing
Rate Charges for the Demand of Each Hour on a Typical Non-Work Day During the Summer Months
Variable Names: LRATE (IHR, KYRHLF, Nowork)

Data Card #35 Demand Pricing
Rate Charges for the Demand of Each Hour on a Typical Non-Work Day During the Winter Months
Variable Names: LRATE (IHR, KYRHLF, Nowork)
Data Card #32 Time of Day Pricing
Rate Charges for the Demand of Each Hour on a Typical Work Day During the Summer Months
Variable Names: LRATE (IHR, KYRHLF, Nowork)

Data Card #33 Time of Day Pricing
Rate Charges for the Demand of Each Hour on a Typical Work Day During the Winter Months
Variable Names: LRATE (IHR, KYRHLF, Nowork)
Data Card #34 Time of Day Pricing
Rate Charges for the Demand of Each Hour on a Typical Non-Work Day During the Summer Months
Variable Names: L_RATE (IHR, KYRHLF, Nowork)

Data Card #35 Time of Day Pricing
Rate Charges for the Demand of Each Hour on a Typical Non-Work Day During the Winter Months
Variable Names: L_RATE (IHR, KYRHLF, Nowork)
Data Card #36
Number of Days Per Month
Variable Names: PERMO (Month)
Data Card #37
Current Fuel Prices
Variable Names: GTFLC, DSLFLC, STTFLC, BRFLC
Data Card #38
Operating and Maintenance Costs Per Unit
Variable Names: GTPKOM, GTCGOM, DSPKOM, DSCGOM, STPKOM, STCGOM, BLROM, WASTOM

7.00  4.00  35.00  12.00  1.15  1.15  1.21  1.00

Data Card #39 Time of Day Pricing
Operating and Maintenance Costs Per Month
Variable Names: GTOM, DSOM, STOM, BLFOM, THRSTM
Data Card #40
Utility Company Monthly Charges for the Demand Rate Schedule
Variable Names: CHMTR, DCHPK, DCHOFF, ECHPK, ECHOFF, FLADJ

9000.

Data Card #41
Utility Company Billing Demand for the Demand Rate Schedule
Variable Names: DMDPK
Data Card #40
Utility Company Charges for the Time of Day Rate Structure
Variable Names: CHMTR, DCHPK, DCHMID, DCHOFF, ECHPK, ECHMID, ECHOFF, FLADJ

Data Card #41
Utility Company Peak Demands for the Time of Day Rate Structure
Variable Names: DMDPK, DMDMID, DMDOFF
Data Card #42
Sales Price/Purchase Price Ratio
Variable Names: SALPR
Data Card #43
Years Pertaining to the Life Cycle Cost Analysis
Variable Names: NOWYR, INSTYR, JYRCHN, LIFE
Data Card #44
Escalation Rates for the Life Cycle Cost Analysis
Variable Names: FESTGT, FELTGT, FESTDS, FELTDS, FESTST, FELTST, FESTBL, FELTBL

| 0.056 | 0.0 | 0.13 | 0.07 | 0.10 |

Data Card #45
Escalation Rates for the Life Cycle Cost Analysis
Variable Names: OMESCS, OMESCL, ELESST, ELESLT, DISC

-11-