A Model for Assessing the Economic and Energy Savings Implications of Cogeneration with Steam Turbines in Citrus Processing Plants

Spring 1981

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A MODEL FOR ASSESSING THE ECONOMIC AND ENERGY SAVINGS IMPLICATIONS OF COGENERATION WITH STEAM TURBINES IN CITRUS PROCESSING PLANTS

BY

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B.S., United States Naval Academy, 1946

RESEARCH REPORT

Submitted in partial fulfillment of the requirements for the degree of Master of Science in the Graduate Studies Program of the College of Engineering at the University of Central Florida at Orlando, Florida

Winter Quarter 1981
ABSTRACT

A cogeneration system using a noncondensing steam turbine to simultaneously provide electricity and process steam to a citrus plant was modeled in order to assess the source energy savings and the economic implications with the employment of this type system under conditions of time varying plant energy demand.

Average monthly energy demand data from one citrus plant was analyzed. It was determined that the important parameter, in addition to a minimum demand level, for assessing economic acceptability is the demand thermal to electric ratio. One set of steam conditions will not necessarily provide the maximum source energy savings and at the same time be the most economically beneficial. The values of the economic criteria will remain relatively constant over a range of rated turbine capacities for each set of steam conditions.
ACKNOWLEDGEMENT

The author sincerely thanks all those individuals who voluntarily and otherwise gave assistance during the conduct of the study. Those persons who were especially helpful included Dr. Burton Eno, Mr. Antonio Minardi and Professor James Beck and Mike Wang. A very special acknowledgement is given Dr. Patricia J. Bishop for her encouragement, advice and unfailing support during all phases of the study. My sincere appreciation and special thanks is given Mrs. Linda Stewart for her complete cooperation and expert accomplishment of the stenographic effort involved in the preparation, review and publishing of this report.
# TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>Chapter</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACKNOWLEDGEMENT</td>
<td>iii</td>
</tr>
<tr>
<td>I. INTRODUCTION</td>
<td>1</td>
</tr>
<tr>
<td>- Introduction</td>
<td></td>
</tr>
<tr>
<td>Purpose of the Study</td>
<td></td>
</tr>
<tr>
<td>Principle Advantage of Cogeneration</td>
<td></td>
</tr>
<tr>
<td>II. CITRUS PLANT ENERGY PROFILE</td>
<td>4</td>
</tr>
<tr>
<td>- Production Flow in Citrus Plants</td>
<td></td>
</tr>
<tr>
<td>- Energy Usage</td>
<td></td>
</tr>
<tr>
<td>III. STEAM TURBINE COGENERATION SYSTEM DESIGN</td>
<td>10</td>
</tr>
<tr>
<td>- Condensing Turbine Characteristics</td>
<td></td>
</tr>
<tr>
<td>- Noncondensing Turbine Characteristics</td>
<td></td>
</tr>
<tr>
<td>- Steam Turbine Selection</td>
<td></td>
</tr>
<tr>
<td>- Cogeneration System Model</td>
<td></td>
</tr>
<tr>
<td>IV. MODEL DESCRIPTION</td>
<td>17</td>
</tr>
<tr>
<td>- Model Description</td>
<td></td>
</tr>
<tr>
<td>- Turbo-Generator Energy Output Characteristic Module</td>
<td></td>
</tr>
<tr>
<td>- Matching Plant Energy Demands to Turbo-Generator Energy Output Characteristics</td>
<td></td>
</tr>
<tr>
<td>- Determination of Average Annual Energy Savings</td>
<td></td>
</tr>
<tr>
<td>- Economic Criteria Rationale and Logic</td>
<td></td>
</tr>
<tr>
<td>- Cost Factors</td>
<td></td>
</tr>
<tr>
<td>- Program Output Data</td>
<td></td>
</tr>
<tr>
<td>V. ANALYSIS OF CITRUS PLANT</td>
<td>37</td>
</tr>
<tr>
<td>- Basis for Analysis</td>
<td></td>
</tr>
<tr>
<td>- Discussion of the Results</td>
<td></td>
</tr>
<tr>
<td>- Implications of Averaging Plant Energy Demands</td>
<td></td>
</tr>
<tr>
<td>- Implications of Selling Excess Electricity to the Utility</td>
<td></td>
</tr>
</tbody>
</table>
VI. LIMITATION OF THE STUDY

Limitation of the Study
Conclusions
Further Research

APPENDIX 1
APPENDIX 2
APPENDIX 3
LIST OF REFERENCES
LIST OF TABLES

TABLE 1 - Summation of Analyses Results ............... 39
TABLE 2 - Comparison of Results Using Average Monthly
and Average Yearly Demand Data with 400 PSIG
Cogeneration System ....................... 52
## LIST OF FIGURES

<table>
<thead>
<tr>
<th>FIGURE</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 - Energy Saving Potential with Cogeneration</td>
<td>3</td>
</tr>
<tr>
<td>2 - Production Flow in Citrus Plant</td>
<td>5</td>
</tr>
<tr>
<td>3 - Citrus Plant Electrical Demand</td>
<td>7</td>
</tr>
<tr>
<td>4 - Citrus Plant Average Monthly Electric and Thermal</td>
<td>8</td>
</tr>
<tr>
<td>Demands for Major Processing Months</td>
<td></td>
</tr>
<tr>
<td>5 - Generalized Energy Performance Map for Condensing</td>
<td>11</td>
</tr>
<tr>
<td>Steam Turbine with Automatic Extraction</td>
<td></td>
</tr>
<tr>
<td>6 - Generalized Energy Performance Map for Noncondensing</td>
<td>13</td>
</tr>
<tr>
<td>Steam Turbine with Automatic Extraction</td>
<td></td>
</tr>
<tr>
<td>7 - Block Schematic of Cogeneration System</td>
<td>15</td>
</tr>
<tr>
<td>8 - Variation of Efficiency of Small Multistage Turbines</td>
<td>19</td>
</tr>
<tr>
<td>with Size and Pressure</td>
<td></td>
</tr>
<tr>
<td>9 - William's Line Plot</td>
<td>21</td>
</tr>
<tr>
<td>10 - Energy Demand Plot</td>
<td>25</td>
</tr>
<tr>
<td>11 - Average Annual Energy Saved Versus Rated Turbo-</td>
<td>41</td>
</tr>
<tr>
<td>Generator Capacity</td>
<td></td>
</tr>
<tr>
<td>12 - Average Annual Energy Saved Versus Payback Period</td>
<td>42</td>
</tr>
<tr>
<td>13 - Percent Change of Annual Energy Savings Vs Change in Steam</td>
<td>43</td>
</tr>
<tr>
<td>Generation System Efficiencies</td>
<td></td>
</tr>
<tr>
<td>14 - Percent Change in Payback Period with Change in Steam</td>
<td>45</td>
</tr>
<tr>
<td>Generating System Efficiency</td>
<td></td>
</tr>
<tr>
<td>15 - Percent Change in Annual Energy Savings Versus Change in Turbine</td>
<td>46</td>
</tr>
<tr>
<td>Efficiency</td>
<td></td>
</tr>
<tr>
<td>16 - Percent Change in Payback Period with Change in Turbine</td>
<td>47</td>
</tr>
<tr>
<td>Efficiency</td>
<td></td>
</tr>
</tbody>
</table>
17 - Payback Period Versus Cost of Boiler Fuel ........ 49
18 - Payback Period Versus Cost of Electricity ........ 50
CHAPTER I
INTRODUCTION
1.1 INTRODUCTION

With the realization of the limitations on the size of our current known energy resources has also come an increasing awareness of the need for energy conservation. New as well as old conservation concepts are being studied to determine their utility in the current and forecasted future economic and social environment.

The University of Central Florida has undertaken studies [1] on behalf of the Governor's Energy Office with the purpose of identifying energy conservation techniques and systems which could be economically applied in the various sectors of the Florida economy. In the analysis of the large energy consuming industrial plants, it was found that the citrus plants appeared to be good candidates for cogeneration. But large variation with time of energy demands, both electrical and thermal, required an analytical model of some sophistication to determine the optimum cogeneration system and to assess the economic and energy savings implication of such a system. Cogeneration as used herein is defined as the simultaneous production of electrical and thermal energy from the same fuel source.

1.2 PURPOSE OF THE STUDY

The primary purpose of this research effort was the development of the needed analytical model. A secondary purpose of the research was the assessment of the initial feasibility in terms of energy saved and economic acceptability of cogeneration at one citrus plant whose monthly energy demand data was made available.
1.3 PRINCIPLE ADVANTAGE OF COGENERATION

Cogeneration using steam turbines is not new but has been applied to some extent since the turn of the century [2]. Its principle advantage results from the significant savings in fuel over the conventional or common method of supplying process steam direct from a plant boiler and electricity from a public utility company. The savings is illustrated in Figure 1 and shows that a fuel savings of approximately 36% is possible in supplying equal amounts of electricity and thermal energy using current technology steam turbo-generator equipment. A perfectly matched turbine output to plant demand is assumed although this seldom occurs in practice.
Fig. 1 Energy saving potential with cogeneration
CHAPTER II

CITRUS PLANT ENERGY PROFILE
2.1 PRODUCTION FLOW IN CITRUS PLANTS

Before developing the characteristics of the analytical model it is necessary to describe the energy usage in citrus plants that impact on the cogeneration system being investigated. Most of the energy consumed in citrus processing plants is used in the production of citrus juices with very small quantities being involved in the packaging of fruit for distribution. The production flow chart for the processing of fruit to juice is shown in Figure 2. After off-loading, the fruit is placed in storage bins. From the bins it is transported to the juicing machines and then to the evaporators where water is boiled off to concentrate the juice. The pulp from the juicers is pressed to further remove moisture and then fed to a drier kiln. The dried pulp is pressed into pellets and sold for livestock feed. The liquid from the pulp presses is further concentrated in the evaporators. The concentrated fruit juices are removed as demand dictates and the juices from the various varieties are mixed to give proper flavor and chemical content. The mixed concentrate is either recombined with water, packaged and sold as juice or canned, frozen and sold as frozen concentrate.

2.2 ENERGY USAGE

The evaporators are the primary users of process steam. The plants visited had several sets of juice evaporators of varying capacities. All of the production activities contribute to the electrical load but the freeze tunnel used in freezing the canned juice
Fig. 2 Production flow in citrus plant
concentrate and the equipment involved in juice concentration are the large consumers. Figure 3 is a single day's plot of electrical demand for one of the citrus plants and illustrates the electric loading with changing production activity. During the period of juice concentration activities, boiler output was approximately one-third of that experienced when the plant operated at maximum capacity.

In general, the steam demand is dependent on the flow of citrus fruit to the plant. The electrical demand is dependent not only on this flow but also on the demand for the juice products. As a result, the plant energy demands vary with time and the steam (thermal) demand and the electrical demand will vary somewhat independently of each other.

A histogram of the average monthly energy demands over an annual operating cycle of the citrus plant to be analysed is presented in Figure 4. The plot represents only that energy use which could be satisfied with the cogeneration system and not total plant demand. These demands were derived from plant records of monthly fuel and electrical use and monthly amounts of fruit processed. The details of the derivation of the average monthly demand is presented in Appendix 1. It is to be noted, for the eight months fruit is processed in quantity average monthly thermal demand varies over a wide range from about 8000 KWH/H to about 20000 KWH/H while electric demand is more steady varying from about 3800 KWH/H to 6000 KWH/H. The plant's thermal demand is defined as the difference in steam enthalpy to the process less the enthalpy of the condensate return multiplied by the steam flow.
Annual Average Thermal Demand 149.4 BIL. BTU's
Annual Average Electric Demand 13.2 MIL. Kwh's

Fig. 4 Citrus plant average monthly electric and thermal demands for major processing months
An energy survey [3] of one citrus plant by the Energy Management Services, Applied Technical Division of the DuPont Corporation reported 80% of the plant thermal demand could be satisfied with steam at a pressure of 5 psig for juice and molasses evaporator heating. Visits at other plants confirmed this percentage of use in evaporator heating. This is an average percentage and will vary with time. Since data was not available to allow determination of thermal demand at the various pressures over time a constant percentage is assumed. Thermal energy from turbine automatic extraction points will be assumed to be at a constant fraction of total thermal energy discharged by the turbine.
CHAPTER III

STEAM TURBINE COGENERATION
SYSTEM DESIGN
3.1 CONDENSING TURBINE CHARACTERISTICS

Two basic types of turbines can be used for the topping cogeneration system to be modeled, a condensing turbine with automatic extraction or a noncondensing turbine with or without automatic extraction. Ports are provided in the condensing turbine casing after a given number of stages depending on the desired steam pressure to be extracted. The extracted steam can then be used as the source of steam to the production process stations. Steam which is not extracted continues through additional stages and finally exhausts to a condenser. Since industrial steam turbo-generating systems are much less efficient than those of the public utility, that amount of electricity produced as a result of steam flow from throttle to condenser exhaust will require greater fuel expenditure than if provided by the utility.

Figure 5 is a generalized energy performance map of the condensing turbine and is designed to show the capability of the turbine to satisfy process steam and electrical demands. This plot is easily generated from the William's Line Plots normally provided by the turbine manufacturer. All energy demand points which fall in the region between the maximum extraction line and the electric output axis (zero extraction line) can be satisfied from the turbo-generator outputs. These extraction lines will subsequently be referred to as the turbine energy output characteristic lines.

The condensing turbine requires a source of condenser cooling
Fig. 5 Generalized energy performance map for condensing steam turbine with automatic extraction
water and if not available in the necessary quantities from natural water sources can require the use of cooling towers. Since water resources are at a premium in many parts of Florida, cooling towers will undoubtedly be required at many of the citrus plants. These towers will greatly reduce the economic viability of cogeneration with this type turbine because of the costs involved.

3.2 NONCONDENSING TURBINE CHARACTERISTICS

The noncondensing turbine when used for cogeneration is operated at a back pressure consistent with the lower pressures required at the process stations. Steam requirements intermediate to the throttle and exhaust back pressure can be accommodated by one or more automatic extraction points. The performance map of this type turbine is shown in Figure 6. The noncondensing turbine can satisfy all energy demands in the region between the extraction lines. The energy output characteristic line at zero extraction rate does not coincide with the electrical output axis. If the turbine does not have automatic extraction then all turbine energy output points fall on the energy output characteristic line for zero extraction. If energy extracted is to be a constant fraction of output then all turbine energy output points will form a single plot. It is to be noted that for all process demand points falling within the region below the energy output characteristic line for zero extraction only the thermal part of the process demand can be satisfied by the turbine. The noncondensing turbine cannot operate at an electric loading greater than that which is required to satisfy steam process demand from the turbine steam discharge points. Thus it has less flexi-
Fig. 6 Generalized energy performance map for noncondensing steam turbine with automatic extraction
bility in meeting varying electrical and steam demands than the con-
densing turbine.

3.3 STEAM TURBINE SELECTION

The noncondensing turbine with an option to include a single extraction point will be used in the model. A primary goal of cogeneration is the savings of source energy. The additional electrical generation possible with the condensing turbine requires a greater consumption of source energy than if obtained from the utility. The additional savings in utility electric costs possible with the condensing turbine must more than offset the additional investment and operating costs. With current fuel and electric utility prices this will not happen. Boiler fuel costs are projected to inflate at a greater rate than the cost of utility electricity (1) and therefore it is not likely that condensing turbines will become more economically attractive in the future.

The choice of automatic extraction will depend primarily on the economic advantage. About 80% of the steam demand at citrus plants requires pressures less than 20 psig which can be supplied from the turbine exhaust. The remaining 20% is at pressures between 250 and 90 psig. The additional costs for automatic extraction to supply the 20% of demand at the higher pressures must be offset by lower energy costs.

3.4 COGENERATION SYSTEM MODEL

A block schematic of the system to be modeled is shown in Figure 7. Those system operating parameters used to describe the operating characteristics are also shown. The steam generating block
Fig. 7 Block schematic of cogeneration system
efficiency also includes the line losses to the turbines and to the process stations. The line direct from the boiler to the production process stations will allow for the additional supply of process steam in excess of that which can be supplied from the turbine discharge. Similarly a tie to the utility grid is shown as a means of satisfying electrical demands in excess of that which can be provided by the turbo-generator. The model will also permit, if desired, the selling of electricity to the utility should electricity be generated in excess of plant demand in order to satisfy the thermal (steam) demand.

The operating characteristics of the system are described by the steam enthalpies at various points in the system, the rated capacity of the turbo-generator and efficiencies of the various system components. Using these parameters the model will generate the energy output performance characteristics for the system and match them to the plant process demand. The intermediate outputs will be the thermal energy supplied from the turbine, the thermal energy supplied direct from the boiler to process stations, the electricity supplied by the generator, and the electricity supplied by or sold to the public utility. From the intermediate outputs and appropriate efficiencies, fuel used by the plant boiler and the public utility in meeting the plant demand can be computed. The difference between the fuel required with the conventional system and the fuel use by the cogeneration system gives the value of the energy savings. By applying the appropriate cost factors the monetary savings can be computed.
CHAPTER IV
MODEL DESCRIPTION
4.0 MODEL DESCRIPTION

To satisfy the purpose for its construction, the model must permit the identification of cogeneration system characteristics for optimum energy savings and economics. It must also allow for the evaluation of the interrelationship between energy savings and the economics. This is accomplished by stepping through a range of rated turbo-generator capacities for a given set of steam operating conditions identified by the input values of enthalpy at the key points in the system. The maximum rated capacity and the stepping increment is established by the data input but the lowest rated capacity is set at 500 KW. To evaluate the effects of differing steam conditions requires repeated runs of the model. To operate in this manner requires the inclusion of equations which establish the relationship between system operating parameters and the turbo-generator rated capacities.

4.2 TURBO-GENERATOR ENERGY OUTPUT CHARACTERISTIC MODULE

To compute energy outputs of the cogeneration system the plant energy demand must be matched to the turbo-generator energy output characteristics. Plant energy demands are provided to the program in three quantities, electrical demand (Pj) in KWH/H, the process thermal to electric demand ratio (HPj), and the time interval over which the demand occurred (Δtj) in hours. Before describing how this matching is accomplished it is necessary to explain the module or subprogram used to generate the energy output characteristics for the turbo-generator.
The values of turbo-generator electric output, thermal energy discharge, thermal to electric output ratio and the thermal energy output per pound of steam discharged by the turbine are computed by this sub-program from the following data received from the main program:

- System steam enthalpies
- Rated turbo-generator electrical load
- Partial load fraction
- Turbine half rated load steam rate factor
- Turbo-generator loss and efficiency factors
- Constants used in equating turbine efficiency to rated electric capacity
- Fraction of total thermal plant energy demand to be supplied at extraction point pressure

The turbine throttle to exhaust efficiency is initially computed. Figure 8 shows that over the range of rated capacities (1000 - 6000 BHP) to be evaluated for the citrus plants the turbine efficiency at rated load is reasonably linear when plotted on a semilog graph. Thus the following equation is used for turbine efficiency.

\[ n_{tl} = (A + B \times \log_{10} PR) \times PLCF \]

where

- \( n_{tl} \) = Turbine efficiency from inlet to exhaust. It is defined as shaft power out divided by the isentropic change in steam enthalpy
- \( A \& B \) = constants identifying the straight line approximations of the efficiency curves. See Appendix 3 for numerical values.
- \( PR \) = Rated load
- \( PLCF \) = Partial load correction factor

The relationship between turbine shaft output and the steam flow rate is nearly linear and is known as a Williams Line, Figure 9. This re-
Fig 8. Variation of efficiency of small multistage turbines with size and pressure

relationship is used to find PLCF as follows:

By definition

$$\text{PLCF} = \frac{\eta_p}{\eta_{PR}}$$ (A)

$\eta_p$ = Efficiency at operating load
$\eta_{PR}$ = Efficiency at rated load

The turbine steam rate (SR) is equal to the theoretical steam rate (TSR) divided by the efficiency at load and multiplied by the load.

Thus

$$SR = \frac{TSR \times P}{\eta_p}$$ (B)

and at rated load

$$SR_R = \frac{TSR \times PR}{\eta_{PR}}$$ (C)

By substituting equations (B) and (C) into (A)

$$\text{PLCF} = PL \times \frac{SR_R}{SR}$$ (D)

where

$$PL = \frac{P}{PR} = \text{the partial load fraction}$$

The equation for the Williams Line, Figure 9, is

$$SR = PL \times (SR_R - SR_O) + SR_O$$ (E)

where

$$SR_O = \text{Steam rate at zero turbine load}$$

Substituting (E) into (D) gives the equation

$$\text{PLCF} = \frac{SR_R}{SR_R - SR_O + SR_O/PL}$$ (F)

Let $\alpha$ equal the half rate load steam rate correction factor

$$\alpha = \frac{SR_{R/2}}{0.5 \times SR_R}$$ (G)

From the Williams Line equation and (G) the following is found

$$SR_O = (\alpha - 1) \times SR_R$$
Fig. 9  William's line plot
and thus

$$\text{PLCF} = \frac{\text{PL}}{2 \cdot \text{PL} + \alpha \cdot (1 - \text{PL}) - 1}$$

As can be seen from Figure 8 the value of $\alpha$ remains relatively constant over the range of rated loads to be considered. Figure 8 and Reference 4 were used as the source of turbine efficiencies and half rated load factors.

No data was discovered which would permit determining the throttle to extraction point efficiency. Reference 4 used a value of 0.05 for the difference in throttle to extraction and throttle to exhaust efficiency for a 25,000 BHP rated turbine operating at throttle steam conditions of 600 psig and 750°F, and at an extraction pressure of 250 psig. In the absence of data, a constant difference over the range of rated loads is assumed and throttle to extraction efficiency is given by

$$n_{t2} = n_{t1} = \text{ECF}$$

where ECF is a data input quantity to be obtained from turbine manufacturers.

The enthalpies of the steam discharged from the exhaust ($H_2$) and the extraction point ($H_3$) is determined by

$$H_2 = H_1 - \Delta h_{s1} \times (n_{t1} + TL)$$

$$H_3 = H_1 - \Delta h_{s2} \times (n_{t2} + TL)$$

where

$H_1$ = Steam enthalpy at the throttle

$\Delta h_s$ = Isentropic enthalpy change across the turbine

$TL$ = Fraction of turbine loss due to mechanical losses
If no extraction is to occur, $H_3$ is set to zero and the plant thermal demand data is accordingly reduced.

$S$ is defined as the fraction of total plant thermal energy demand which is to be provided at extraction pressure and

$$S = \frac{m_3 x (H_3 - H_4)}{(m_2 x (H_2 - H_4) + m_3 x (H_3 - H_4))}$$

where

$m_2$ = Fraction of total turbine steam flow rate discharged from the exhaust

$m_3$ = Fraction of total turbine steam flow rate discharged from extraction point

$H_4$ = Condensate enthalpy from the process stations

From this relationship and the fact $m_2 + m_3$ must equal to one

$$m_3 = \frac{[S x (H_2 - H_4)]}{[(1-S) x H_3 - H_4] + S x (H_2 - H_4)]}$$

$$m_2 = 1 - m_3$$

The thermal content of the steam discharged from the turbine per unit mass of steam ($H_5$) in terms of the energy extraction at the process stations is then

$$H_5 = m_2 x (H_2 - H_4) + m_3 x (H_3 - H_4)$$

The thermal discharge to electric power output ratio of the turbine at operating load (HPG) is given as

$$HPG = \frac{H_5}{\left[(m_2 x \Delta h_{s1} x n_{t1} + m_3 x \Delta h_{s2} x n_{t2}) x n_R x n_g x PF\right]}$$

where

$n_R$ = Reduction gear efficiency
\[ n_g = \text{Generator efficiency} \]

\[ PF = \text{Plant electric power factor} \]

The program assumes only turbo-generators with rated electric loads of less than 2500 KW will be equipped with reduction gears.

The turbine energy output characteristic subprogram finally calculates the electric power generated (PG) and the thermal energy discharge (PHG)

\[ PG = PL \times PR \]

\[ PHG = HPG \times PG \]

4.3 MATCHING PLANT ENERGY DEMANDS TO TURBO-GENERATOR ENERGY OUTPUT CHARACTERISTICS

The energy demand plot, Figure 10, is a graphical means of displaying the matching logic used in the program. It is a plot of thermal versus electric plant demands with lines drawn at the maximum plant demand for each category. The enclosed area therefore represents the space containing all possible plant demand points. A representative turbine energy output characteristic line is shown and dashed lines are drawn at the rated turbine output point parallel to each axis. Finally a dashed line is drawn from the origin to the turbine rated load point, the slope of the line being equal to the thermal to electric output ratio for the turbine at rated electric load. The lines described, subdivide the space of all possible demand points into six regions. Each region can be described, as shown by a set of inequalities involving some or all of the following quantities; \( P_j, PR, PH_j, HR, HP_j, HPR \) and \( HPG \), where \( PH_j \) is the plant process thermal demand for the \( j \)th demand set.
Fig. 10 Energy demand plot
Once the applicable region has been established by the program for the jth demand point, the amount of energy supplied from each energy source to satisfy the demand is computed. The power generated ($PG_j$), electric power received from ($PUI_j$) or sold to ($PUO_j$) the utility company, thermal energy supplied by the turbine ($PHG_j$) and that direct from the boiler ($PHR_j$) are determined. These are summed and factored to give average annual values. The value of $H_{5j}$ is computed and used to find the steam rate through the turbine.

In region A both thermal and electric demand exceeds the rated capability of the turbo-generator and

\[
PG_j = PR \\
PHG_j = HR \\
PHR_j = PH_j - PHG_j \\
PUI_j = P_j - PG \\
PUO_j = 0
\]

Demand points in region B exceed the rated electric load of the turbo-generator but are less than the rated thermal discharge. Since the turbo-generator loading cannot exceed that which will satisfy the plant thermal demand the turbine will operate at a partial load. The turbine energy output characteristic subprogram is entered with a value of

\[
PL = PH_j/HR
\]

and is iterated with updated values of

\[
PL = \frac{PG}{PR} \times \frac{PH_j}{PHG}
\]

until

\[
PHG_j = PH_j
\]
then

\[ P_{UI,j} = P_j - PG_j \]
\[ PUO_j = 0 \]
\[ PHR_j = 0 \]

Thermal demand exceeds rated turbine thermal discharge but electric demand is less than the turbo-generator rated electric load in region C. If excess electricity is to be sold

\[ PG_j = PR \]
\[ PUO_j = PR = P_j \]
\[ PUI_j = 0 \]
\[ PHG_j = HR \]
\[ PHR_j = PH_j - HR \]

If excess electricity is not to be sold, the turbo-generator is operated at partial load equal to

\[ PL = P_j / PR \]

and

\[ PG_j = P_j \]
\[ PUI_j = 0 \]
\[ PUO_j = 0 \]
\[ PHR_j = PH_j, - PHG_j \]

Both the thermal and electric demand in region D is less than the rated turbine load and the turbine loading is computed in the same manner as for region B, thus

\[ P_{UI,j} = P_j - PG_j \]
\[ PHO_j = 0 \]
\[ PHG_j = PH_j \]
\[ PHR_j = 0 \]
Excess electricity can be generated in region E. If the excess is to be sold then the turbine energy output characteristics subprogram is entered as for region B and

\[ \begin{align*}
PUO_j &= PG - P_j \\
PUI_j &= 0 \\
PHG_j &= PH_j \\
PHR_j &= 0
\end{align*} \]

If the excess electricity is not sold then the turbine energy output characteristic subprogram is entered with the value of partial load

\[ PL = \frac{P_j}{PR} \]

and

\[ \begin{align*}
PG_j &= P_j \\
PUI_j &= 0 \\
PUO_j &= 0 \\
PHR_j &= PH_j - PHG_j
\end{align*} \]

The energy matching for the demand points in region F is the same as for region D.

It is to be noted that demands points in regions B, D and F which fall below the point of intersection of the turbine energy output characteristic line and the thermal energy axis cannot be practically matched to the turbine output since zero electrical output would occur. Hence partial loading is limited to a value of 0.1 or greater.

4.4 DETERMINATION OF AVERAGE ANNUAL ENERGY SAVINGS

The energy savings to be determined is the source fuel (HHV) saved by cogeneration over the conventional method of supplying the needed energy. It is computed by adding the difference in source fuel used by the utility company to the difference in source fuel used by
the plant in its auxiliary boilers.

To determine the value of energy saved, it is first necessary to find the steam flow rate for each jth demand point by

\[
SR_j = SR1_j + SR2_j
\]

\[
SR1_j = \frac{PHG_j}{H5_j}
\]

\[
SR2_j = \frac{PHR_j}{(H_6 - H_4)}
\]

where

\[
H_6 = \text{enthalpy of steam at boiler pressure and at saturated temperature}
\]

The total fuel (HHV) \(QU_{1j} \) used by the utility in providing the electricity during the jth period with cogeneration is

\[
QU_{1j} = \left[ (PUI_j - PUO_j) \times \Delta t_j \right] / \eta_u
\]

where

\[
\Delta t_j = \text{Time interval of the jth demand, hours}
\]

\[
\eta_u = \text{Utility plant overall generating efficiency}
\]

The total boiler fuel (HHV) \(QS_{1j} \) used during the jth demand period with cogeneration is

\[
QS_{1j} = \left[ SR1_j \times (H_1 - H_4) + SR2_j \times (H_6 - H_4) \right] \times \Delta t_j / \eta_{sg1}
\]

where

\[
\eta_{sg1} = \text{Steam generating system efficiency with cogeneration}
\]

The average annual values of \(QU_{1A} \) and \(QS_{1A} \) are obtained by

\[
QU_{1A} = \left[ \sum_{j=1}^{JJ} QU_{1j} \right] / PY
\]

\[
QS_{1A} = \left[ \sum_{j=1}^{JJ} QS_{1j} \right] / PY
\]
where:

\[ JJ = \text{Number of energy demand periods} \]

\[ PY = \text{Number of demand periods per year} \]

The average annual values of boiler fuel (HHV) \((\text{QS2A})\) and utility fuel (HHV) \((\text{QU2A})\) used without cogeneration is determined by:

\[ \text{QU2A} = \left[ \sum_{j=1}^{JJ} (p_j \times \Delta t_j) \div \eta_u \right] / PY \]

\[ \text{QS2A} = \left[ \sum_{j=1}^{JJ} (p_j \times \Delta t_j) \div \eta_{sq2} \right] / PY \]

where

\[ \eta_{sq2} = \text{Steam generation system efficiency without cogeneration} \]

The average annual energy savings \((\text{ES})\) is thus determined by subtracting the energy used with cogeneration from the energy used without cogeneration:

\[ \text{ES} = \text{QS2A} + \text{QUA2} - (\text{QUA1} + \text{QS1A}) \]

4.5 ECONOMIC CRITERIA RATIONALE AND LOGIC

Regardless of the energy savings which may result from the installation of the cogeneration system, industry will not procure the system unless there is a reasonable return on investment. Cogeneration must compete economically with other projects vying for the investment capital of the industry. The savings in energy costs must be sufficient to produce the required return on investment. The simple payback period is used most often as the initial criteria for evaluating the economic acceptability of proposed projects requiring investment funds [1]. Simple payback period is the length of time it takes to recover the initial investment from the net before tax cash flow savings without discounting for interest or inflation rates. The equation for
The simple payback period used is:

$$PB = \frac{CI}{(AS - CM)}$$

where

- $PB$ = payback period, years
- $CI$ = additional investment costs for cogeneration
- $CM$ = annual operating and maintenance costs
- $AS$ = annual savings using cogeneration

The annual savings ($AS$) is the difference between the annual cost for plant energy with and without cogeneration. It is computed from the following relationship:

$$AS = (PA - PUIA + PUOA) \times CE + (QS2 - QS1) \times CF$$

where

- $PA$ = average annual plant electric use
- $PUIA$ = average annual plant electricity procured from utilities with cogeneration
- $PUOA$ = average annual electricity sold back to utility
- $CE$, $CF$ = cost of electricity, cost of fuel

If the project falls within the industry's range of acceptable payback values, a more detailed economic analysis is accomplished. This analysis is usually a form of after tax discounted cash flow return on investment. The return on investment is the discount rate which makes the discounted after tax cash flows over the economic life of the equipment equal to the capital costs. The return on investment analysis can be calculated either on an inflation free basis meaning that the cost of money (interest) rates, discount factors and expenses do not include the effect of inflation or inflation effects can be included. This study will use the present worth approach in computing
a return on investment and will include the effects of energy inflation rates. The analysis will provide a rate of return on investment after the effects of inflation have been removed. No attempt is made to account for the time flow of capital out and it is assumed that the full investment tax credit of 10% of the investment costs can be taken in the first year of operation. Further is it assumed that operation and maintenance costs remain constant over the life of the system except for inflation. Depreciation is computed by the Double Declining Balance Method. The equation for the return on investment analysis is:

\[
0.9 \text{CI} = \sum_{K=1}^{n} \left[ \frac{\text{PE} \times \text{CE} \times (1+\text{EEE})^{K-1} + \text{Q} \times \text{CF} \times (1+\text{EE})^{K-1}}{(1+i)^K \times (1+r)^K} \right] - \frac{\text{CM}}{(1+r)^K} \frac{[1-T]}{[1-T]} + \frac{\text{D} \times \text{T}}{(1+i)^K \times (1+r)^K}
\]

where

- \text{PE} = \text{PA} - \text{PUIA} + \text{PUOA}, \text{KWH} - \text{Difference in utility energy used with and without cogeneration}
- \text{QA} = \text{OS1} - \text{OS2}, \text{BTU} - \text{Difference in boiler fuel used with and without cogeneration}
- \text{EEE} = \text{Inflation rate of electricity costs}
- \text{i} = \text{Inflation rate}
- \text{r} = \text{Rate of return on investment}
- \text{EE} = \text{Inflation rate of boiler fuel costs}
- \text{CF} = \text{Boiler fuel costs}
- \text{CE} = \text{Electrical costs}
- \text{D} = \text{Depreciation in jth year}
- \text{T} = \text{Tax rate}
The computer program iterates this equation with increasing values of \( r \) until the equality is satisfied at a value of \( n \) equal to the economic life of the equipment [1].

4.6 COST FACTORS

The cost factors used in the economic analysis were derived from a number of sources. The cost of energy and energy inflation rates are determined from the projected prices of fuels and electricity in the South Atlantic Region, 1980-1995 as promulgated in the Federal Register, January 23, 1980. The general inflation rate \( (i) \) was determined from the total price index change through 1990 as published in the Chase Econometrics Associates Inc., forecast dated November 1979.

Since the analytical model is designed to generate outputs over a range of rated capacities it was necessary to find the relationship between costs and rated capacities. Reference 2 reported that steam turbine generator costs vary with size raised to the 0.8 power and that heat exchangers costs vary with size raised to the 0.6 power. These relationships were used in the equations for calculating equipment costs. These are:

\[
BC = SGC \times SRT^{0.6} \\
TGC = TGC_1 \times PR^{0.8}
\]

where

\[
BC = \text{Steam generation system costs} \\
SGC = \text{Steam generation cost constant} \\
TGC = \text{Turbo generation system costs}
\]
TGCl = Turbo generation system cost constant
PR = Rated turbo-generation capacity
SRT = Rated boiler capacity

The system costs include equipment costs and all related costs such as engineering, site construction, installation, etc.

Since only those additional costs associated with the cogeneration capability need be considered, the initial investment costs (CI) are determined by the following relationship:

\[ CI = TGC + BC = SGCC \]

where

SGCC = the cost of the conventional system

The annual operating and maintenance costs (CM) also include only the incremental increase due to the cogeneration capability. An annual labor cost may be entered as a non-varying cost while all other O & M costs can only be included as a fraction of the investment cost (CI) and:

\[ CM = PC + CCF \times CI \]

where

CM = annual additional O & M cost, $
PC = annual additional labor costs, $
CCF = fraction by which investment cost is to be multiplied to obtain O & M costs other than labor

It is to be noted that additional boiler fuel costs due to cogeneration are not included in CM but are accounted for in the computation of annual savings (AS).
Investment and operation and maintenance costs are difficult to acquire. One supplier of boilers and heat exchangers did give cost estimates. The other costs were based on the costing data in References 2, 5 and 6.

4.6 PROGRAM OUTPUT DATA

The computer program for the analytical model is contained in Appendix 2. The program prints the following data for each rated turbo generator load analyzed:

A. Rated turbo-generator capacity, in KW
B. Average annual process thermal energy required in billions of BTUs
C. Average annual electrical use in millions of KWHs
D. Annual value of electricity cogenerated in millions of KWHs
E. Annual value of electricity received from the utility in millions of KWHs
F. Annual value of electricity sold to the utility in millions of KWHs
G. Annual value of process thermal energy supplied by the turbine in billions of BTUs
H. Annual value of process thermal heat supplied direct from the boiler in billions of BTUs
I. Maximum boiler steam rate in thousands of lbs. per hour
J. Average annual energy saved with cogeneration in billions of BTUs
K. Investment costs for cogeneration in thousands of dollars
L. Annual operating and maintenance cost in thousands of dollars
M. Annual monetary value of energy savings with cogeneration in thousands of dollars
P. Payback period in years
Q. Rate of return on investment
CHAPTER V

ANALYSIS OF CITRUS PLANT
5.1 BASIS FOR THE ANALYSIS

Monthly energy use data over a three year period was available from a previous study effort [7]. In the absence of daily or hourly demand data the average monthly use data was reduced to an average monthly demand form as described in Appendix 1. A tabulation of the demand data is also contained in Appendix 1. These plant demands were matched to turbo-generators with electrical output capacities running from 500 KW to 5000 KW in increments of 500 KW. Four different steam conditions at the turbine throttle were analyzed. These steam conditions were:

- 900 psig, 750F
- 600 psig, 750F
- 400 psig, Saturated Temperature
- 200 psig, Saturated Temperature

Automatic extraction at 250 psig was included for rated capacities equal to or greater than 2500 KW when operating at steam throttle pressures of 400 psig or greater and the exhaust back pressure was set at 5 psig.

The conventional system used in the analytic model was the steam generation system now installed in the citrus plant.

Appendix 3 lists the data inputs for each set of steam conditions analyzed.

5.2 DISCUSSION OF THE RESULTS

The total average annual energy use by the process stations
available for cogeneration was found to be $140 \times 10^9$ BTUs of thermal and $13.2 \times 10^6$ KWHs of electricity. Table 1 is the summation of the results attained from the computer program. With the exception of the 200 psig steam case, total plant thermal demand was supplied by the turbine over a range of rated loads, while only 50% or less of the electrical demand was cogenerated. This is caused by the plant demand points lying mostly in the region below the turbine energy output characteristic line meaning that the thermal to electric demand ratio was generally lower than the turbine output ratio. The plant demand data shows the average plant thermal to electric demand ratio to be about 3.5. Turbines operating with the exhaust and extraction steam conditions for the analysis will have rated thermal to electric output ratios between about 5 and 8 for the system steam conditions used. The increasing values of maximum energy saved with increased values of steam conditions is also partially explained by this difference in energy ratios, since the higher the values of steam conditions at the throttle the lower the turbine thermal to electrical output ratio.

The steam generation efficiencies will increase with increasing steam pressures and temperatures further enhancing the energy savings at the higher steam pressures.

The curves of rated turbo-generator capacity to annual energy savings, Figure 11, each show a maximum point. At the rated loads less than that for the maximum point, the ability of the turbo-generator to satisfy plant demand is limited by its rated capacity. At the rated loads greater than at the maximum point, any increase in the ability of the turbine to satisfy plant electrical demand is more than offset
TABLE 1. SUMMATION OF ANALYSES RESULTS

<table>
<thead>
<tr>
<th>PARAMETER/RATED TURBO-GEN. LOAD, KW</th>
<th>200</th>
<th>400(MS)</th>
<th>600</th>
<th>900</th>
</tr>
</thead>
<tbody>
<tr>
<td>MAXIMUM SOURCE ENERGY SAVED - 10^9 BTU</td>
<td>27.5</td>
<td>44.4</td>
<td>58.6</td>
<td>73.6</td>
</tr>
<tr>
<td></td>
<td>1500</td>
<td>2500</td>
<td>2500</td>
<td>4000-5000</td>
</tr>
<tr>
<td>MAXIMUM ELECTRICITY SUPPLIED FROM TURBO-GENERATOR -10^6 KWH</td>
<td>3.8</td>
<td>5.9</td>
<td>6.5</td>
<td>6.9</td>
</tr>
<tr>
<td></td>
<td>1500</td>
<td>2500</td>
<td>2500</td>
<td>3000</td>
</tr>
<tr>
<td>MAXIMUM THERMAL ENERGY SUPPLIED FROM TURBO-GENERATOR -10^9 BTU</td>
<td>119.4</td>
<td>149.4</td>
<td>149.4</td>
<td>149.4</td>
</tr>
<tr>
<td></td>
<td>2000</td>
<td>3500-4000</td>
<td>3500-4000</td>
<td>4000-5000</td>
</tr>
<tr>
<td>MAXIMUM STEAL RATE -10^3 lb/hr</td>
<td>77.7</td>
<td>83</td>
<td>71.9</td>
<td>73.6</td>
</tr>
<tr>
<td></td>
<td>2500</td>
<td>3500</td>
<td>3500-4000</td>
<td>4000-5000</td>
</tr>
<tr>
<td>MAXIMUM PAYBACK PERIOD, YEARS</td>
<td>4.5</td>
<td>3.1</td>
<td>7.2</td>
<td>9.2</td>
</tr>
<tr>
<td></td>
<td>500</td>
<td>500</td>
<td>2000</td>
<td>2000</td>
</tr>
<tr>
<td>RATE OF RETURN AT MINIMUM PAYBACK PERIOD, PERCENT</td>
<td>14</td>
<td>22.5</td>
<td>7.0</td>
<td>3.0</td>
</tr>
</tbody>
</table>
by the decrease due to increasing turbine thermal to electric output ratio caused by lower partial loading.

Table 1 shows the total thermal demand is supplied by the 600 and 400 psig systems at intermediate rated capacities but not at the higher ratings, indicating the thermal demands for some demand periods is of such low value to cause the turbines at the higher ratings to be operated at a partial load below the 10% cut-off.

It is evident from Table 1 and Figure 12 that the minimum payback period does not coincide with the condition of maximum source energy savings. This can be attributed to investment and operating costs increasing with rated load at a greater rate than the monetary value of the energy savings. Since a relationship exists between source energy savings and the monetary value of energy savings it can be deduced that the knee in the curves of Figure 12 is a reflection of the maximum characteristic of the curves in Figure 11.

The slope over that section of the curves in Figure 12 below the knee is relatively small implying a range of rated turbine loads where the increase in cost with turbine size is nearly offset by the increase in the monetary value of the energy saved. The part of the curves in Figure 13 where the slope is small corresponds to the portions of the curves in Figure 12 where the slope is large. It is evident that this occurs at rated turbine capacities at 2500 KW and less.

The 400 psig system gives the lowest payback period and is the more economical if a major replacement of the existing steam generation equipment was otherwise necessary. The program was provided with
Fig. 11 Average annual energy saved versus rated turbine-generator capacity
Fig. 12 Average annual energy saved versus payback period
Fig. 13 Percent change of annual energy savings vs change in steam generation system efficiencies.
data based on this assumption for the steam conditions differing from those of the existing installation. The 200 psig system reflects the economics of cogeneration utilizing the existing steam generation equipment. Management generally favors only those projects with simple payback periods of two years or less [1]. Hence, cogeneration for the citrus plant appears to be marginal from an economic standpoint.

A 500 KW cogenerating system gives the minimum payback period for both the 200 and 400 psig systems. However, the results indicate that a range of rated loads may be considered with only small change in the overall economics being involved.

5.3 SENSITIVITY ANALYSIS

Sensitivity analyses were conducted on the 400 psig system and steam generation system efficiency was found to be the most sensitive of all operating characteristic parameters. Figures 13 and 14 show the percent change in energy savings and payback period with changes in this parameter. A 0.05 change in efficiency results in a 30 to 50% change in energy savings, depending on the rated load of the turbo-generator. The percentage change is greater with a reduction of efficiency. The change in payback period behaves in a similar manner, where a 0.05 reduction in efficiency increases payback by 60 to 80% while an increase of 0.05 gives only a 25% decrease in payback period.

The effect of errors in turbine efficiencies, Figures 15 and 16, is significant at the higher rated loads but not at the lower ratings. Errors in reduction gear and generator mechanical efficiencies and the plant power factor will have comparable effects on the
Fig. 14 Percent change in payback period with change in steam generating system efficiency.
Fig. 15 Percent change in annual energy savings versus change in turbine efficiency
Fig. 16  Percent change in payback period with change in turbine efficiency
results. The effects vary considerably over the range of rated loads with but small errors being introduced at a rated turbine load of 1000 KW. The relative insensitivity to turbine efficiency suggests the use of less efficient and less costly turbines at the lower rated loads where a single stage turbine could be used instead of a multistage turbine.

The sensitivity of payback period, Figure 17, to the cost of boiler fuel (natural gas for this analysis) is small when compared to the cost of electricity. From Figure 18, a doubling of the cost of electricity decreases the payback period by about 50% for a 1000 KW system while the doubling of boiler fuel costs increases payback by only about 2%. The payback is almost directly proportional to investment costs. Operating and maintenance costs have a small effect, and doubling these costs for the 1000 KW rated system changes payback by about 5%.

5.4 IMPLICATION OF AVERAGING PLANT ENERGY DEMANDS

The time averaging of plant energy demand introduces error into the analysis. The greater the dispersion of the demand points about the mean the greater will be the error introduced into the results of the analysis.

A quantitative assessment of the effects of using average monthly plant demands cannot be made in the absence of hourly or daily demand data. During those months of near full production little error is likely to be introduced since demand should be relatively stable. During months of partial production processing of citrus fruit the error could be significant.
Fig. 17 Payback period versus cost of boiler fuel
STEAM AT THROTTLE:
400 PSIG SATURATED TEMP.

Fig. 18 Payback period versus cost of electricity
Table 2 shows the comparison of the results attained using the averaged monthly data and an annual average yearly demand computed from the average monthly data. Small difference is noted and could be deduced from the small dispersion of the average monthly data sets.

5.6 IMPLICATIONS OF SELLING EXCESS ELECTRICITY TO THE UTILITY

The plant demand used in this analysis does not include demand points in those regions of the demand plot where excess electricity could be generated. Thus, the option of selling excess electricity that is cogenerated does not enter into the evaluation.
### TABLE 2
COMPARISON OF RESULTS USING AVERAGE MONTHLY AND AVERAGE YEARLY DEMAND DATA WITH 400 PSIG COGENERATION SYSTEM

<table>
<thead>
<tr>
<th>RATED CAPACITY, KW</th>
<th>ENERGY SAVED $10^9$ BTUs</th>
<th>PAYBACK PERIOD YEARS</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>MONTHLY</td>
<td>YEARLY</td>
</tr>
<tr>
<td>1000</td>
<td>28.5</td>
<td>28.5</td>
</tr>
<tr>
<td>2000</td>
<td>42.7</td>
<td>44.7</td>
</tr>
<tr>
<td>3000</td>
<td>43.4</td>
<td>43.5</td>
</tr>
<tr>
<td>4000</td>
<td>40.2</td>
<td>40.4</td>
</tr>
<tr>
<td>5000</td>
<td>36.9</td>
<td>37.0</td>
</tr>
</tbody>
</table>
CHAPTER VI
LIMITATION OF THE STUDY
6.1 LIMITATION OF THE STUDY

The analytical model developed in this study was developed for use in exploring the energy savings and economic implications of a particular cogeneration system for citrus plants. It is designed to permit the managers of the plants to determine the feasibility of expending further resources in a more rigorous and detailed analysis. It further identifies the range of system parameters to be considered in a more detailed design study. The use of the approximate relationships between pertinent system operating parameters plus the combining of many parameters, essentially limits the use of the model for system design to the role of initial sizing. The model can be used for other industrial plants if the energy profile of the activity can be accommodated by the model.

The accuracy of the analysis of the citrus plant was limited by the accuracy of the demand input data and by the lack of accurate budget quality cost data. No quantitative estimate of the overall accuracy of the results is possible, but qualitative estimates are ± 30% in the average annual energy savings results and ± 100% in the payback and rate of return quantities. Even with errors of this magnitude certain valid conclusions can be enunciated.

6.2 CONCLUSIONS

The major contribution of this effort is the development of the analytical model for evaluating the noncondensing steam turbine in cogeneration under conditions of varying plant energy demands. The utility of the model will depend on the availability of plant demand data over sufficiently small time periods to give the desired accu-
racy of results.

The plant energy parameter which most influences the economic acceptability of a noncondensing steam turbine cogeneration system is the plant thermal to electric demand ratio. Plants with demand ratios of less than 4 to 5 will probably not be good candidates for this type of cogeneration because of marginal to unacceptable economics.

There will be an optimum steam condition and rated turbogenerator capacity for each set of plant demands that will be most economically advantageous. This will not necessarily be the system giving the maximum energy savings.

There will be a range of rated turbine sizes for a given set of steam conditions over which the payback period will remain relatively constant.

6.3 FURTHER RESEARCH

Since most plant energy use data will probably be in the form of total monthly use of plant fuel and electricity, the implication of monthly averaging of plant energy demand should be understood. Thus the collection of hourly demand data over an appropriate period of time would permit the assessment of the error due to demand averaging.

Another worthwhile effort would be to refine the operating and cost input data over a narrow range of system operating characteristics in order to further assess the accuracy of the analytical model when used to give results over a range of system capabilities.
APPENDIX 1
AVERAGE MONTHLY ENERGY DEMAND DATA

Monthly fuel, natural gas and petroleum distillate, and electricity use for a three year period by one citrus plant was used as the plant energy requirements for this study. Monthly production rates in the form of boxes of citrus fruit processed was used as the basis for deriving the energy demand which could be satisfied by the cogeneration system. The periods when cogeneration can occur is during periods when boilers are providing steam to the evaporators. Thus, cogeneration will occur during fresh fruit processing to juice concentrate.

From the production data it was deduced that full production gave production rates of about 3000 boxes per hour. Production rates normally drop during periods of less than full production thus the hourly production rate for these periods is assumed to be about 2500 boxes per hour. The hours for cogeneration was determined by dividing the monthly production by an average hourly production rate.

The average electric demand was based on monthly electric usage and the peak demand for the month. For those months when full or nearly full production occurred, average monthly demand ranged from 80 to 90% of the peak demand. During other months of lower production rates average monthly demand ranged as low as about 50% of peak demand. It was assumed that demand during fruit processing would be 70-90% of peak demand depending on the monthly amount of fruit processed. Electric demand was thus assumed to be:
70% of peak for low production months
80% of peak for medium production months
90% of peak for high production months

The monthly thermal energy provided by steam used in production was determined by multiplying the boiler fuel used (HHV) by the steam generation system efficiency estimated to be 0.75. The monthly thermal use was divided by the number of hours of cogeneration to determine the hourly demand. This divided by the electrical demand gave the value of the thermal to electric demand ratio for the month.

Plant monthly energy use data in the form required by the program is listed. The major processing of fruit occurs over an eight month period and 24 data sets are given for the three year period.

<table>
<thead>
<tr>
<th>$P_j$</th>
<th>$\overline{HP_j}$</th>
<th>$\overline{\Delta t_j}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>4650.00</td>
<td>2.69</td>
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</table>
A PROGRAM TO PREDICT THE ECONOMICS & ENERGY SAVINGS IN CITRUS PROCESSING PLANTS BY STEAM TURBINE COGENERATION

DIMENSION P(25), HP(25), FA(25)
INTEGER PRT, PI, FB
READ PLANT ENERGY REQUIREMENTS: P(N)= ELECT DEMAND IN KWH/H
HP(N)= RATIO OF THERMAL TO ELECT DEMAND, FA(N)= TIME INCREMENT
OVER WHICH THE NTH ENERGY DEMANDS HAVE BEEN AVERAGED IN HOURS
DO 900 N=1,24
   READ(S,6)P(N), HP(N), FA(N)
 WRITE(6,8) P(N), HP(N), FA(N)
FORMAT(3F10.2)
900 CONTINUE
READ STEAM ENTHALPIES IN BTUS/LBM
H1= AT TURBINE INLET, H4= FEEDWATER TO STM. GEN. PLANT
H6= SATURATED STM AT BOILER OP PRESS., HS2= AT TUR EXH WITH ISENTROPIC EXP.
PANSION, HS3= AT TUR EXTRACTION PT. WITH ISENTROPIC EXP.
READ H1, H4, H6, HS2, HS3
WRITE(6,5) H1, H4, H6, HS2, HS3
5 FORMAT(3X, 'H1=',F6.1, 2X, 'H4=', F6.1, 2X, 'H6=', F6.1, 2X, 'HS2=', F6.1, 2X, 'HS3=', F6.1)
READ TUR-GEN DP CHAR (DEL S= ISENTROPIC ENTHALPY CHANGE IN TUR):
PRT= MAX RATED LOAD IN KW, TL=TUR MECH LOSS FACTOR (MECH LOSS= TL * DEL S)
PF= ELECT PWR FACTOR, EFF= DIFF TUR EFF AT EXH & EXTR PT, A&B= CONSTANTS
FOR DETERMINING TUR INLET TO EXH EFF AT RATED LOAD (PR) (EFF=SHAFT PWR/
DELS = A+B*ALG10(PR) (PR IN KW), C= HALF LOAD STM RATE FACTOR
FOR TUR WITH RATED LOAD OF PRT/2. SS= FRACTION OF THERMAL DEMAND AT EXTR PT PRESS. ER= REDUCT GEAR EFF, EG= GEN EFF
READ PRT, TL, PF, EFF, A, B, C, SS, ER, EG
WRITE(6,6) PRT, TL, PF, EFF, A, B, C, SS, ER, EG
2'ER'='F4.2,2X,'EO'='F4.2)
STM GEN OF CHAR & MISC. JJ= NO. PLANT ENERGY DATA PERIODS, KEY-GEN
BEG= NO. OF EXC ELECT GEN KEY=0, ESGR= STM GEN PLANT EFF, TUR-GEN, ESGR= STM GEN PLANT EFF \( \frac{W}{D} \)
COST OF COGEN, PI=_INCREMENTING SIZE FOR VARYING TUR-GEN RATED LOAD IN KWS
WRITE(6,7) JJ,KEY,FB,ESGR,EU.PI,ESGR.
WRITE(6,7) JJ,KEY,FB,ESGR,EU.PI,ESGR.
READ IN ECONOMIC DATA: TGC1= TUR-GEN COST PARAMETER \( \frac{\$}{000} \) WITH EXTR.
TGC2= TUR-GEN COST PARAMETER \( \frac{\$}{000} \) W/D EXTR., SGC= STM GEN SYS COST PARA
MEIER \( \frac{\$}{000} \), SGC= COST OF STM GEN SYS \( \frac{\$}{000} \), PC= FIXED ANN
O&M COST FOR COGEN, CCF= FRACTION OF INITIAL INVEST COST TO ALLOCATE
FOR ANN O&M COSTS, EEE= INFLATION RATE OF ELECT COSTS, INFLATION
RATING FUEL EXTRACTION AT= GENERAL INFLATION RATE, T= INCOME TAX RATE,
L= EQUIP LIFE IN YEARS, CF= COST OF BOILER FUEL \( \# \) BIL BTUS.
CE= ELECT COST \( \frac{\$}{MIL KWHs} \).
WRITE(6,9) TGC1,TGC2,SGC,SGC,PC,CF,CEE,EE,AA,T,CF,CE
WRITE(6,9) TGC1,TGC2,SGC,SGC,PC,CF,CEE,EE,AA,T,CF,CE
FORMAT(3X, 'TGC1=',F4.2,'TGC2=',F4.2,'SGC=',F4.2,'PC=',F4.2,'CF=',F4.2,'CEE=',F4.2)
FORMAT(3X, 'TGC1=',F4.2,'TGC2=',F4.2,'SGC=',F4.2,'PC=',F4.2,'CF=',F4.2,'CEE=',F4.2)
3'LJ=',12.2X,'CF=',1.2X,'CEE=',1.2X.
3'LJ=',12.2X,'CF=',1.2X,'CEE=',1.2X.
WRITE(6,19)
WRITE(6,19)
FORMAT(9,5X,'HT IN BILLION BTUS-ENERGY IN MILLION KWH'/5X,
1'RATE OF RETURN (ROR) IN PERCENT-STEAM RATE (SR) IN MLB/HR'/5X,
3X, ALL QUANTITIES ARE AVERAGE ANNUAL VALUES
5')
WRITE(6,21)
WRITE(6,21)
FORMAT(9,1X,'RATED',2X,'PROCESS',3X,'ELEC',3X,
1'READ (H5B3 EQ. H1) SJ= 0. 0',1X,
2'READ FM',3X,'MAX SR',2X,'ENERGY',2X,'INVEST',4X,'O-M',4X,
3'REGR',5X,'PAY',4X,'ROR',4X,'CAP',4X,'HT REG',3X,'REG',4X,'GEN',
4'REG',3X,'UTIL',5X,'TUR',2X,'RED',3X,'SAVE',4X,'COST',5X,
5'REGR',3X,'SAVE',4X,'BACK'.
5'REGR',3X,'SAVE',4X,'BACK'.
ESTABLISH END VALUE OF RATED GEN CAPACITY DD LOOP (NOTE PROGRAM
OUTPUT PROVIDE OUTPUT DATA FOR RATED TUR-GEN LOADS FROM PRT TO 500 KW
IN MJ INCREMENTS) II= ((PRT-500)/P1)+1
ESTABLISH END VALUE OF RATED GEN CAPACITY DD LOOP (NOTE PROGRAM
OUTPUT PROVIDE OUTPUT DATA FOR RATED TUR-GEN LOADS FROM PRT TO 500 KW
IN MJ INCREMENTS) II= ((PRT-500)/P1)+1
S=SS
S=SS
IF(H5B3 EQ. H1) SJ= 0. 0
IF(H5B3 EQ. H1) SJ= 0. 0
COMMENCE STEPPING THROUGH DESIRED RANGE OF RATED TUR-GEN OUTPUTS(PR)
DO 100 1=1,II
DO 100 1=1,II
IF(PR LT 2900) NO AUTO EXTR IS TO OCCUR
IF(PR LT 2900) NO AUTO EXTR IS TO OCCUR
IF(PR LT 2900) SJ= 0
IF(PR LT 2900) SJ= 0
Determine TUR-GEN RATED LOAD OUTPUTS. H5R= THERMAL OUTPUT IN KWH/LBM STM
Determine TUR-GEN RATED LOAD OUTPUTS. H5R= THERMAL OUTPUT IN KWH/LBM STM
HR= THERMAL OUTPUT IN KWH/H HPR= HR/PR PL=1
HR= THERMAL OUTPUT IN KWH/H HPR= HR/PR PL=1
CALL HTOP(H1,HS3,HS3,HA,PR,TL,PF,PL,EFF,A,B,C,S,ER,EG,
CALL HTOP(H1,HS3,HS3,HA,PR,TL,PF,PL,EFF,A,B,C,S,ER,EG,
1PH,2PH,HPG,HPG)
1PH,2PH,HPG,HPG)
HPG=HPG
HPG=HPG
HR=PR+HPR
HR=PR+HPR
HS=HS
HS=HS
SET INITIAL CONDITIONS OF TOTAL ENERGY PARAMETERS AND STEP THROUGH
SET INITIAL CONDITIONS OF TOTAL ENERGY PARAMETERS AND STEP THROUGH
PLANT TIME INCREMENTED ENERGY DEMANDS (ALL IN UNITS OF KWH)
PLANT TIME INCREMENTED ENERGY DEMANDS (ALL IN UNITS OF KWH)
PU= ELECT FROM UTILITY CO, PU= ELECT FROM UTILITY CO,
PGHT= PROCESS THERMAL ENERGY FROM TUR, PHR= PROCESS THERMAL ENERGY
DIRECT FROM STM PLANT, H= PROCESS THERMAL ENERGY DEMAND, PT= PLANT
DIRECT FROM STM PLANT, H= PROCESS THERMAL ENERGY DEMAND, PT= PLANT
DEMAND, 
DEMAND,
PT= MAX STM RATE, TST= BLR FUEL(MHV) \times WITH
TST= BLR FUEL(MHV) \times WITH
COGEN IN BILL. BTU, QUI= SOURCE FUEL(HHV) FOR ELECT FROM UTILITY CO
COGEN IN BILL. BTU, QUI= SOURCE FUEL(HHV) FOR ELECT FROM UTILITY CO
PU=0. 0
PU=0. 0
PGT=0. 0
PGT=0. 0
HR=0. 0
HR=0. 0
PT=0. 0
PT=0. 0
GST=0. 0
GST=0. 0
QUI=0. 0
QUI=0. 0
J=-1, JU
J=-1, JU
Determine the Thermal Demand (PH) & THERMAL TO ELECT DEMAND RATIO (HPD)
Determine the Thermal Demand (PH) & THERMAL TO ELECT DEMAND RATIO (HPD)
TO BE MATCHED WITH THERMAL DISCHARGE FOR THE JTH DATA PERIOD
TO BE MATCHED WITH THERMAL DISCHARGE FOR THE JTH DATA PERIOD
IF(S IE QI ) GO TO 105
IF(S IE QI ) GO TO 105
P=PH(J)+1
P=PH(J)+1
HPD=HP(J)
HPD=HP(J)
GO TO 105
GO TO 105
105
105
PH=(1.-SS)*HP(J)
PH=(1.-SS)*HP(J)
HPD=HP(J)
HPD=HP(J)
DETERMINE ELECT GEN (PGJ), TUR CONTRIBUTION TO THERMAL DEMAND (PHGJ), AND THERMAL CONTENT OF TUR DISCHARGE (H5J) FOR THE JTH DATA PERIOD

FOR CASE P(J) GE PR OR PH GE HR
IF (P(J) LT PR OR PH LT HR) GO TO 110
PGJ=PR
PHGJ=HR
H5J=H5R
GO TO 190

FOR CASE P(J) GE PR & PH LT HR
IF (P(J) LT PR) GO TO 120
ITERATE TUR-GEN LOADING UNTIL TUR THERMAL OUTPUT MATCHES THERMAL DEMAND
PL=PH/HR
IF (PL LT 0.1) GO TO 167
DO 300 K=1,50
CALL HTOP (H1, HS2, HS3, H4, PR, TL, PF, PL, EEF, A, B, C, S, ER, EG, 1PG, PHG, HPG, H5)
PPP=PHG/PH
IF (PPP GT 0.995 AND PPP LT 1.0) GO TO 130
PL=PG*PH/PHG/PR
IF (PL LT 0.1) GO TO 187
300 CONTINUE
GO TO 185

FOR CASE P(J) LT PR & PH GE HR & NO EXCESS ELECT GEN
IF (PH, LT HR OR KEY, EQ 1) GO TO 140
PL=PH/HR
IF (PL LT 1) GO TO 197
CALL HTOP (H1, HS2, HS3, H4, PR, TL, PF, PL, EEF, A, B, C, S, ER, EG, 1PG, PHG, HPG, H5)
PCJ=PG
PPGJ=PHG
H5J=H5R
GO TO 190

FOR CASE P(J) LT PR & PH GE HR & EXCESS ELECT GEN
IF (PH, LT HR) GO TO 150
PCJ=PR
PPGJ=HR
H5J=H5R
GO TO 190

FOR CASE P(J) LT PR & PH LT HR & HPO LE HPR
IF (HPO, GT HPR) GO TO 160
PL=PH/HR
IF (PL LT 0.1) GO TO 187
DO 400 K=1,50
CALL HTOP (H1, HS2, HS3, H4, PR, TL, PF, PL, EEF, A, B, C, S, ER, EG, 1PG, PHG, HPG, H5)
PPP=PHG/PH
IF (PPP GT 0.995 AND PPP LT 1.0) GO TO 165
PL=PG*PH/PHG/PR
IF (PL LT 0.1) GO TO 187
400 CONTINUE
GO TO 185

FOR CASE P(J) LT PR & PH LT HR & HPO GT HPR & HPO GT HPO
IF (PL LT 0.1) GO TO 187
CALL HTOP (H1, HS2, HS3, H4, PR, TL, PF, PL, EEF, A, B, C, S, ER, EG, 1PG, PHG, HPG, H5)
IF (HPO LE HPO) GO TO 170
DO 500 K=1,50
PL=PG*PH/PHG/PR
CALL HTOP (H1, HS2, HS3, H4, PR, TL, PF, PL, EEF, A, B, C, S, ER, EG, 1PG, PHG, HPG, H5)
PPP=PHG/PH
IF (PPP GT 0.995 AND PPP LT 1.0) GO TO 175
500 CONTINUE
GO TO 185

FOR CASE P(J) LT PR & PH LT HR & HPO GT HPR & HPG LE HPO & NO EXCESS ELECT GEN
IF (KEY, EQ 1) GO TO 180
GO TO 185

FOR CASE P(J) LT PR & PH LT HR & HPO GT HPR & HPG LE HPO & EXCESS ELECT GEN
DO 600 KKKK=1,50
PL=PG*PH/PHG/PR
IF (PL LT 0.1) GO TO 187
CALL HTOP (H1, HS2, HS3, H4, PR, TL, PF, PL, EEF, A, B, C, S, ER, EG, 1PG, PHG, HPG, H5)
PPP=PHG/PH
IF (PPP GT 0.995 AND PPP LT 1.0) GO TO 185
600 CONTINUE
GO TO 185

PGJ=PH
DETERMINE PROCESS THERMAL ENERGY DIRECT FROM STM GEN PLANT (PHRJ),
STMT RATE FOR THE JTH DATA PERIOD (SRJ) & MAX STM RATE (SRT)
SR1(J) = STM RATE THROUGH TUR, SR2(J) = STM RATE DIRECT TO PROCESS

PHR = P(J) * HP(J)
IF(PHGJ, LT, PHR) GO TO 191
PHR = 0
SR2 = 0
GO TO 192

PHR = PHRJ - PHGJ
SR2 = PHRJ * 3.413/(H6 - H4)
IF(H5U, EQ, 0) GO TO 192
SR1 = PHGJ * 3.413/H5J
GO TO 193

SR1 = 0
SR3 = SR1 + SR2
IF(SR3, GT, SRT) SRT = SR3

DETERMINE ELECT FROM UTILITY (PUIJ) AND ELECT SOLD (PUOJ) FOR THE JTH
DATA PERIOD
IF(P(J) - PGJ) 30, 30, 40
PUIJ = 0
PUOJ = PGJ - P(J)
GO TO 195

PUIJ = P(J) - PGJ
PUOJ = 0

CALCULATE TOTAL ENERGY PARAMETERS
PUI = PUIJ + PUIJ * FA(J)
PUO = PUOJ + PUOJ * FA(J)
PT = PTJ + PTJ * FA(J)
H = HPJ * P(J) * FA(J)
GTJ = GTJ1 + H1/H4 * SR1J + H6/H4 * SR2J / EESG * FA(J)

CONTINUE CALCULATE AVERAGE ANNUAL ENERGY PARAMETERS - ELECT IN MIL OF KWH - THERMAL
IN BIL OF BTUS

PGA = PT/J + FC
PUIA = PUI + FC
PUOA = PUO + FC
PHA = PHA + FC
PHRA = PHR + FC
QSA = GST1 + FC
QUA = QU1 + FC
QSB = GST2 + FC
QUA2 = PT/J + FD/EU
HA = H + FD

CALCULATE AVERAGE ANNUAL ENERGY SAVINGS (ES) WITH COGEN IN BIL OF BTUS
ES = GS2 + QUA2 - QUA - GS1
CALCULATE THE AVERAGE ANNUAL SAVINGS WITH COGEN IN $(000)
AS = (PA - PUIA + PUOJ)/CE + (GS2 - GS1) * CF)/1000
CALCULATE THE STM GEN SYSTEM COSTS (BC) IN $(000)
BC = SGCC * SRT ** 0.6
IF(BC, LT, SGCC) BC = SGCC
CALCULATE THE INITIAL INVESTMENT COST (CI) $(000)
CI = TGC1 * PR ** 0.8 - BC - SGCC
IF(S, EQ, 0) CI = TGC2 * PR ** 0.8 + BC - SGCC
CALCULATE ANNUAL O&M COSTS $(000)
CM = PC - CCF * CI
PE = PA - PUIA + PUO
QG = GS2 - GS1
CALCULATE CREDIT (AS, CI, CM, PE, QA, CE, CF, EEE, EE, AI, T, L, PB, R)
WRITE(6, 20) PR, HA, PA, PQA, PUIA, PUA, PHQA, PHRA, SRT, ES, CI, CM, AS, PB, R

CONTINUE STOP

SUBROUTINE HTOP(H1, HS2, HS3, H4, PR, TL, PF, PL, EEF, A, B, C, S, ER,
1EG, PG, PHG, HPG, H5)
THIS SUBROUTINE CALCULATES THE THERMAL ENERGY DISCHARGED FROM THE TUR
FOR PLANT USE (PHG), TUR-GEN ELECT OUTPUT (PG), THE PHG/PG RATIO (HPG)
AND THERMAL CONTENT OF STM FROM TUR (H5) IN BTUS/LB STM. INPUTS ARE TUR-GEN CHAR, STEAM ENTHALPIES, FRACTION OF STEAM TO BE OBTAINED FROM AUTO EXTRACTION PT AND PARTIAL LOAD FACTOR (PL).

12 ET2=ALOG10((1.0/(2.1-PL*(1-C/PL))))
CALCULATE TURBINE INLET TO EXTR EFF (ET3)

10 FM2=1.0
FM3=0.
CALCULATE THERMAL CONTENT OF STM FROM TUR AVAILABLE TO PROCESS(H5)

20 H5=(FM2*(H2-H4)+FM3*(H3-H4))

THermal energy from tur (PHG)

PHG=(FM2*(H1-H5)*ET2+FM3*(H1-H5)*ET3)*PF*ER*EG
PG=PR*PL
PHG=PG*PHG
RETURN

END

SUBROUTINE ECON(AS, CI, CM, PE, GA, CE, CF, EEE, EE, AI, T, L, PB, R)
THIS SUBROUTINE ASSesses THE ECONOMIC FEASIBILITY OF COGEN IN TERMS OF NON-DISCOUNTED SIMPLE PAYBACK PERIOD AND AFTER TAX RATE OF RETURN USING PRESENT WORTH DISCOUNT METHOD CALCULATE SIMPLE PAYBACK PERIOD (PB)
PB= CI/(AS-CM)
DR=2.0/FLOAT(L)

CALCULATE DISCOUNTING FACTORS
GR = 1.0/(1.0+R)
GC=1.0/((1.0+AI)*(1.0+R))

CALCULATE INVESTMENT COSTS AFTER INVESTMENT TAX CREDIT (CIT)
CIT=CI*0.9

COMPUTE YEARLY FUNDS EARNED DURING KTH YEAR (CICK) WITH CURRENT VALUE OF 'R' UNTIL CUMULATIVE VALUE IS EQUAL TO CIT
DO 400 ~ = 1,50
IF(CI . LT. 0.9) GO TO 60
D=CI*DR**(~-1)*DR
DT=DT+D
DE=DT-D
DT=2.0*CI
80 IF(K.GT. L) D = 0

COMPUTE FUNDS EARNED FOR THE KTH YEAR
70 CICK=(PE*CE*(1+EEE)**(K-1)+CM*CF*(1.0)**(K-1))
1 (1000*(1.0+AI)**(1.0)**(K-1)+CM*GR**K)**(1.0+T)+D*T*GC**K
CIC=CIC+CICK
IF YEARS REQUIRED TO AMORTIZE INITIAL INVESTMENT COSTS(K) IS LESS THAN LIFE OF EQUIP (L) INCREASE VALUE OF 'R' AND REcompute UNTIL LIFE OF EQUIP (L) INCREASE VALUE OF 'R' AND REcompute. CONTINUE UNTIL VALUE OF 'R' IS REACHED WHERE COSTS ARE AMORTIZED IN 'L' YEARS
IF(CIC.GE.CIT) GO TO 100

400 CONTINUE
100 IF(K.LT. L) GO TO 60
RETURN
END
# APPENDIX 3

## COGENERATION SYSTEM INPUT DATA FOR THE CITRUS PLANT ANALYSIS

<table>
<thead>
<tr>
<th>INPUT DESCRIPTION</th>
<th>SYM&lt;sup&gt;G&lt;/sup&gt;</th>
<th>900</th>
<th>600</th>
<th>400</th>
<th>200</th>
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<td>BTU/lbm</td>
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<tr>
<td>Turbine Throttle</td>
<td>HI</td>
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<td>Condensate Return</td>
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<td>100.0</td>
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<tr>
<td>Saturated Steam at Boiler</td>
<td>H6</td>
<td>1196.9</td>
<td>1203.4</td>
<td>1204.7</td>
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<tr>
<td>Turbine Exh. After Isentropic Expansion</td>
<td>HS2</td>
<td>1034.4</td>
<td>1071.4</td>
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<td>Turbine Extraction After Isentropic Expansion</td>
<td>HS3</td>
<td>1231.2</td>
<td>1276.8</td>
<td>1102.0</td>
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<td><strong>Turbine-Generator Characteristic Data</strong></td>
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<tr>
<td>Maximum Rated Load, KW</td>
<td>PRT</td>
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<td>5000</td>
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<td>Mechanical Loss Factor</td>
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<tr>
<td>Efficiency Difference Extraction &amp; Exhaust</td>
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<tr>
<td>Turbine Efficiency Constant</td>
<td>A</td>
<td>-0.018</td>
<td>0.255</td>
<td>0.305</td>
<td>0.447</td>
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<tr>
<td>Turbine Efficiency Constant</td>
<td>B</td>
<td>0.199</td>
<td>0.133</td>
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<td>Half Load Steam Rate Factor</td>
<td>C</td>
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<td>Fraction Plant Thermal Energy at Extraction Pressure</td>
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<td>0.20</td>
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### Boiler Characteristics and Program Control Data

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<th>SYM²</th>
<th>900</th>
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<td></td>
<td></td>
<td>750</td>
<td>750</td>
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<tr>
<td>Number of Plant Demand Data Sets</td>
<td>JJ</td>
<td>24</td>
<td>24</td>
<td>24</td>
<td>24</td>
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<tr>
<td>Sell to Utility, Yes-1, No-0</td>
<td>Key</td>
<td>0</td>
<td>0</td>
<td>0/1</td>
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<tr>
<td>Number of Plant Demand Data Sets Per Year</td>
<td>FB</td>
<td>8</td>
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<tr>
<td>Steam Generation System Efficiency with Cogeneration</td>
<td>ESGR</td>
<td>0.84</td>
<td>0.84</td>
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<td>Public Utility Plant Efficiency</td>
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<td>Stepping Increment for Turbo Gen Rated Loads, KW</td>
<td>PI</td>
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<td>500</td>
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<td>Steam Generation Efficiency without Cogen.</td>
<td>ESGR²</td>
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### Economic Data Input

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LIST OF REFERENCES


