160
2-30-82
JH

(2)

Dr. 1097

DOE/CS/40263-T5
(DE83002466)

ENERGY

DOZUFIKZOO

ENERGY CONSERVATION IN CITRUS PROCESSING

Final Project Report

By
M. A. Leo
R. I. Lari
N. R. Moore
M. R. Broussard
M. Gyamfi

November 1981

Work Performed Under Contract No. AC03-79CS40263

Sunkist Growers, Inc.
Ontario, California

and

Jet Propulsion Laboratory
California Institute of Technology
Pasadena, California

U. S. DEPARTMENT OF ENERGY

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

DISCLAIMER

"This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof."

This report has been reproduced directly from the best available copy.

Available from the National Technical Information Service, U. S. Department of Commerce, Springfield, Virginia 22161.

Price: Printed Copy A08
Microfiche A01

Codes are used for pricing all publications. The code is determined by the number of pages in the publication. Information pertaining to the pricing codes can be found in the current issues of the following publications, which are generally available in most libraries: *Energy Research Abstracts, (ERA)*; *Government Reports Announcements and Index (GRA and I)*; *Scientific and Technical Abstract Reports (STAR)*; and publication, NTIS-PR-360 available from (NTIS) at the above address.

ENERGY CONSERVATION IN
CITRUS PROCESSING

FINAL PROJECT REPORT

November, 1981

Prepared by

M. A. Leo
R. I. Lari
Sunkist Growers, Inc.
Ontario, California

and

N. R. Moore
M. R. Broussard
M. Gyamfi
Jet Propulsion Laboratory
California Institute of Technology
Pasadena, California

Prepared for
U.S. Department of Energy
Office of Industrial Programs
Agriculture and Food Processes

PREFACE

Energy conservation through improvements in the energy utilization efficiency of industrial processes is a key element in our nation's future economic growth. This project is a part of an effort by Sunkist Growers to achieve significant reductions of energy usage in citrus processing within the framework of sound business practice. The analysis and evaluation work described herein is intended to be a precursor to individual projects focused on the implementation of practicable energy conservation measures.

This study was carried out jointly by Sunkist Growers and the Jet Propulsion Laboratory under the sponsorship of the U.S. Department of Energy, Office of Industrial Programs. Sunkist Growers, Inc. provided overall management of the project and conducted a portion of the technical work under contract to the Department of Energy. The Jet Propulsion Laboratory performed a portion of the technical work under an arrangement with Sunkist Growers and the National Aeronautics and Space Administration.

The project manager for Sunkist was Mr. M. A. Leo, and the task manager at JPL was Dr. N. R. Moore. The support of the Sunkist and JPL organizations throughout the course of this work is gratefully acknowledged.

ABSTRACT

Alternative energy conserving systems for use in citrus processing plants were synthesized and evaluated in terms of energy savings and economic return. The energy intensive operations that are carried out in citrus processing plants include conveying and extraction, concentration, peel drying, refrigeration, and pasteurization. An examination of the manner in which these operations are performed and how their energy requirements are met provides an opportunity for the application of innovative system concepts to substantially reduce energy demand. The alternative energy conserving systems are synthesized from components and subsystems that are arranged to make use of energy cascading and thermodynamic regeneration to reduce the overall energy usage. This report contains an identification of system requirements such as air pollution rules and plant processing load cycles, a characterization of major operations, description of alternative system concepts, and the evaluation of alternative systems in terms of economic parameters and energy usage.

Under the economic scenarios of this study, certain of the centralized cogeneration systems providing steam and electricity for distribution throughout the plant were found to offer a potential for economic return that merits their serious consideration for near-term implementation. The most attractive alternative system for the peel drying operation was found to offer moderate energy savings of near 12% and to have the potential to become economically viable with a nominal systems development effort. An innovative concept for the integration of cogeneration into the evaporation operation was found to offer substantial energy savings of near 40% relative to a state-of-the-art reference system and to have the potential for economical viability; however, a significant system development effort would be required and is recommended. The pasteurization operation was examined for the application of heat pumps, but the economic return under the conditions of this particular application was found to be decidedly unattractive. An alternate system concept for the refrigeration operation was based on the use of both absorption and vapor-compression cycles driven by a reciprocating or gas turbine engine operating in a cogeneration mode; these systems provided a 20% to 30% reduction of energy usage but do not provide adequate economic benefits. Further analysis of such refrigeration systems could point the way to improving their economic return.

TABLE OF CONTENTS

PREFACE	ii
ABSTRACT	iii
LIST OF FIGURES	vi
LIST OF TABLES	viii
1. INTRODUCTION	1
1.1 Background	1
1.2 Study Approach	2
1.3 Study Objective	2
2. TECHNICAL APPROACH	3
2.1 Operations in Citrus Processing	3
2.2 Types of Alternative Energy Conserving Systems	3
2.3 Components of Operational Units and Subsystems	10
3. STUDY ORGANIZATION AND METHODS	13
3.1 Study Task Structure	13
3.2 Study Methods	13
4. ECONOMIC AND ENVIRONMENTAL FACTORS	21
4.1 Economic Projections	21
4.2 Atmospheric Emissions Requirements	26
5. CITRUS PLANT CHARACTERIZATION AND PROCESS ANALYSIS	29
5.1 Overall Plant Energy Usage and Economic Parameters	29
5.2 Energy Usage in Fruit Conveying and Juice Extraction	36
5.3 Energy Usage of Thermal Multi-effect Juice Evaporation	36
5.4 Peel Dryer Process Characterization and Analysis	36
6. ALTERNATIVE SYSTEMS FOR CITRUS PROCESSING - CONFIGURATION, PERFORMANCE, AND ECONOMICS	46
6.1 System Concepts Considered	46
6.2 Central Cogeneration Systems	46
6.3 Citrus Peel Drying System	64
6.4 Evaporation Systems	81
6.5 Pasteurization and Refrigeration Systems	94
7. FINDINGS AND RECOMMENDATIONS	104

APPENDICES

I	Air Pollution Rules	107
II	Cost Estimate for Central Brayton cogeneration	116
III	Example Economic Calculation for Constant Costs . . .	119
IV	Economic Calculations for Escalating Costs	122
V	Central Cogeneration System Simulation Results for Gas Turbine Engine - Waste Heat Boiler	124
VI	Derivation of Capital Cost Factor	147
VII	Energy and Mass Balance for Multi- effect Evaporation	150
VIII	Energy and Mass Balance for Peel Dryer/Waste Heat Evaporator	155
REFERENCES		158

LIST OF FIGURES

1.	Existing Operations and energy flow paths of the Sunkist citrus processing plant at Ontario, CA	4
2.	An illustration of a Central cogeneration system	5
3.	The three types of Central cogeneration systems considered in this study	7
4.	An illustration of Modular systems for the operations of citrus processing	8
5.	An illustration of an Integrated energy system for a citrus processing plant	9
6.	Schematic diagram of task structure	14
7.	Seasonal variation of fruit load, thermal energy usage, and electricity usage at the Sunkist plant at Ontario, CA for 1979	33
8.	Weekly variation of thermal energy usage with fruit load at the Sunkist plant in Ontario, CA	34
9.	Weekly variation of electricity consumption with fruit load at Sunkist plant in Ontario, CA	35
10.	Hourly variation of boiler fuel consumption for the Sunkist plant at Ontario, CA	37
11.	Flow of fruit through the unloading, conveying, and juice extraction operation	38
12.	Electrical power consumption of the unloading, conveying, and juice extraction operation	39
13.	Steam requirements of multi-effect, forward flow evaporators for 40,000 lb/hr evaporation capacity	41
14.	Diagram of existing dryer/waste heat evaporator system	43
15.	Schematic of dryer turnace and drum	44
16.	System configurations for peel dryer cogeneration	65
17.	Schematic of Modular dual-mode evaporator system	88
18.	Schematic of a modular dual-mode refrigeration unit with a Brayton (gas turbine) engine	98

List of Figures, cont'd.

19.	Schematic of a modular-dual mode evaporator with a reciprocating engine	99
A-VII-1	Schematic diagram with temperatures for a five-effect, forward feed evaporator with seven stages of preheat	151
A-VII-2	Logic diagram for heat and material balances	154

LIST OF TABLES

1.	Tasks comprising the study	15
2.	Annual cost escalation rate projections for energy, capital equipment, and maintenance labor for 1981-2000	22
3.	Historical data and projections for prices of natural gas, electricity, and diesel oil	23
4.	Summary of air pollution rules in the CSCAQMD	28
5.	Annual energy usage by operation - Sunkist Growers Orange Products Division, Ontario, CA	30
6.	Plant parameters and energy costs	31
7.	Electrical power consumption in fruit conveying and juice extraction operation	40
8.	System specifications and performance parameters for the existing Peel dryer/ waste heat evaporator system	45
9.	Alternative systems considered in this study	47
10.	System specifications and performance parameters for Central Brayton cogeneration	48
11.	System specifications and performance parameters for Central Rankine cogeneration	49
12.	System Specifications and Performance Parameters for Central Reciprocating engine cogeneration	50
13.	Capital cost breakdown for Central Brayton cogeneration system	52
14.	Capital cost breakdown for Central Rankine cogeneration system	53
15.	Capital cost breakdown for Central Reciprocating engine cogeneration system	54
16.	Economic characteristics of Central Brayton cogeneration system	55
17.	Economic characteristics of Central Rankine cogeneration system	56
18.	Economic characteristics of Central Reciprocating engine cogeneration system	57

List of Tables, cont'd.

19.	Economics of Central cogeneration systems under escalating costs of fuel, electricity and maintenance for 1980 capital investment	59
20.	Economical evaluation for Central cogeneration systems using constant costs of year of investment per cost projections	60
21.	Energy savings for Central cogeneration system	63
22.	System specification and performance parameters for Parallel Brayton engine/Peel dryer system	67
23.	Energy savings for Parallel Brayton engine/Peel dryer system	68
24.	System specifications and performance parameters for Parallel Reciprocating engine/Peel dryer system	69
25.	Energy savings for Parallel Reciprocating engine/Peel dryer system	71
26.	Capital cost breakdown for Parallel Reciprocating engine/Peel dryer system	72
27.	Economic characteristics of Parallel Reciprocating engine/Peel dryer system	73
28.	System specification and performance parameters for Simple Series Brayton engine/Peel dryer system	74
29.	Energy savings for Simple Series Brayton engine/Peel dryer system	75
30.	System specifications and performance parameters for Series Brayton engine/Afterburner/Peel dryer system	77
31.	Energy savings of Series Brayton engine/ Afterburner/Peel dryer system	78
32.	Capital cost breakdown for Series Brayton engine/Afterburner/Peel dryer system	79
33.	Economic Characteristics of Series Brayton engine/Afterburner/Peel dryer system	80
34.	System specifications and performance parameters for the present evaporator system and for the Modular Thermal Evaporator/Steam Turbine system	84
35.	Energy savings for Modular Thermal Evaporator/ Steam Turbine system	85

List of Tables, cont'd.

36.	Capital cost breakdown for Modular Thermal Evaporator/Steam Turbine system	86
37.	Economic characteristics of Modular Thermal Evaporator/Steam Turbine system	87
38.	System specifications and performance parameters for the Modular Dual-mode Evaporator	89
39.	Energy savings for Modular Dual-mode Evaporator system	91
40.	Capital cost breakdown for Modular Dual-mode Evaporator	92
41.	Economic characteristics of Modular Dual-mode Evaporator	41
42.	Specifications and performance parameters for Modular Heat Pump Pasteurization system	95
43.	Energy savings and economic characteristics of Modular Heat Pump Pasteurization system	96
44.	Specifications and performance parameters for Modular Dual-mode Refrigeration	100
45.	Energy savings for Modular Dual-mode Refrigeration	101
46.	Capital cost breakdown for Modular Dual-mode Refrigeration unit	102
47.	Economic characteristics of Modular Dual-mode Refrigeration	103
A-VII-1	Energy balance for a five effect thermal evaporator	152

1. INTRODUCTION

1.1 Background

The Sunkist citrus processing plant in Ontario, California processes about six million pounds of citrus fruit per day to make a variety of products, which include frozen concentrated juice; chilled, pasteurized, natural strength juice; molasses from peel; dried meal from peel; pectin; citrus oil; and bioflavonoids. The plant requires about 51 million kilowatt-hours of electricity and about 12×10^{11} BTU of thermal energy to meet a typical annual processing load of 600,000 tons of citrus fruit. Presently, all electrical power is purchased from the utility company and all the thermal energy is produced on-site in the furnaces of steam boilers and dryers. Since citrus fruit processing consists of energy intensive operations, the substantially rising costs of fuel and electricity results in much higher processing costs and ultimately in higher market prices for citrus products. Some products may be discontinued if energy costs make them too expensive to compete with imported products or alternatives.

The Sunkist citrus fruit processing plant was originally designed when natural gas and electricity were plentiful and economical forms of energy. Consequently, energy utilization efficiency was not a predominant factor in its original design nor in the original design of other types of food processing plants. The energy intensive operations at the Sunkist plant include:

- (a) evaporation of citrus juice to produce a concentrate, and evaporation of peel liquor to produce molasses;
- (b) refrigeration for chilling, freezing, and storage of citrus juice products;
- (c) pasteurizing and canning of citrus juice;
- (d) drying of peel and pulp to produce dried citrus meal;
- (e) the various electrically driven operations, such as conveying, grinding, pressing, juice extraction, centrifuging, and pelletizing.

1.2 Study Approach

A study of alternative systems to reduce energy usage in citrus processing was focused on the manner in which the energy requirements of the above basic operations are satisfied. The alternative systems for meeting the operational energy requirements consisted of different arrangements of the following major components: evaporators, dryers, heat engines, heat pumps and refrigeration machines, heat exchangers, compressors, pumps, and controls. These systems feature cascaded energy utilization wherein the energy flows of the various components and subsystems are properly matched to meet the requirements of the citrus processing operations. The systems of this study were based on components which, for the most part, are commercially available; however, certain of the alternative systems require the development of new components and controls. Such system and component development requirements are discussed in subsequent sections of this report dealing with specific alternative systems.

1.3 Study Objective

The principal objective of this study was to identify economically viable alternative systems to perform the basic operations of citrus processing while significantly reducing energy usage. The alternative systems are presented in this report in terms of their system configuration, component specifications, analytically predicted performance and operating characteristics, and their projected economic characteristics. This information provides the basis for the identification of the systems that are most desirable in terms of economic viability and reduced energy usage.

2. TECHNICAL APPROACH

2.1 Operations in Citrus Processing

The aforementioned operations of citrus processing are performed by individual assemblages of components that are referred to as operational units. The operational units that were considered in this study are shown in Figure 1 as they exist within the present Sunkist plant in Ontario, California. The five operational units shown in Figure 1 are: evaporation, pasteurization and canning, refrigeration, drying, and the plant electrical load. The process energy requirements within each operational unit were taken as they presently exist, except where known flexibility of process requirements could be advantageously exploited. The energy supply subsystem of Figure 1 consists only of conventional steam boilers and their ancillary equipment, since all electrical power is presently purchased from the utility company.

2.2 Types of Alternative Energy Conserving Systems

The alternative systems considered in this study are classified in four general categories, denoted as Central, Modular, Integrated, and Combined. These categories are distinguished by the extent to which the energy flow paths of the operational units are interrelated.

The Central systems feature a separate central cogeneration system from which energy is supplied to the operational units. The conceptual layout and energy flow paths for a central cogeneration system are illustrated in Figure 2. Since all steam is supplied by a central distribution system and electricity is supplied through the plant's main bus, a central cogeneration system would connect to the existing distribution networks for steam and electricity.

The central cogeneration systems considered in this study consist of a heat engine and a heat recovery boiler or of a boiler and a steam turbine whose exhaust provides process steam. The internal combustion heat engine systems incorporate either a gas

Figure 1. Existing Operations and energy flow paths of the Sunkist citrus processing plant at Ontario, CA

Figure 2. An illustration of a Central cogeneration system

turbine (Brayton) engine-heat recovery boiler unit or a reciprocating (Otto) engine-heat recovery boiler unit. A third system configuration based on the Rankine cycle consists of a boiler that generates steam to drive a turbine which exhausts at a back pressure high enough to provide process steam for the plant. These three cogeneration systems are schematically represented in Figure 3. The preferred fuel for cogeneration systems is natural gas and most industry observers now believe that supplies will be adequate to support industrial cogeneration at less than ten megawatts per installation; therefore, the central cogeneration systems considered here all use natural gas as their primary fuel, as do all the other alternative energy systems.

A Modular system is one of the five operational units wherein an individual energy subsystem is contained within the operational unit. The balance between thermally-driven and work-driven processes within the modular operational units are adjusted to exploit the work producing and heat rejection characteristics of the energy subsystems. Modular systems are illustrated in Figure 4 where the entire plant is shown to consist of independent modular operational units. It is not practical to base an entire plant on modular operational units. However, certain of the individual modular operational units may be economically and functionally desirable given further technical development. In addition, modular operational units may offer significant advantages in practical implementation because they might be put into use with minimal disruption of the existing plant. These possibilities will be discussed in subsequent sections of this report. Modular operational units were considered for evaporation, drying, refrigeration, and pasteurization.

Integrated systems consist of operational units that are configured and interrelated so that they exchange heat and work. An example of an integrated system in which the operational units are configured and interrelated so that no separate energy supply subsystem is required and no electricity is bought from or sold to the utility is shown in Figure 5. As originally envisioned when this

A) RANKINE CYCLE COGENERATION

B) BRAYTON CYCLE COGENERATION

C) RECIPROCATING ENGINE COGENERATION

Figure 3. The three types of Central cogeneration systems considered in this study

Figure 4. An illustration of Modular systems for the operations of citrus processing

Figure 5. An illustration of an Integrated energy system for a citrus processing plant

study was being formulated, Integrated systems were intended to address the problem of unfavorable buyback rates for cogenerated power. However, with the advent of PURPA and with the institution of new rate practices toward cogenerators, the need to consider Integrated systems has vanished. Integrated systems are complex and interfere with established plant operating practices and needs. Frequently, the processing load at citrus plants is not balanced among the operational units and the need arises to independently run the individual operational units. In view of these considerations, Integrated systems were found to be impractical and uneconomic, and are not discussed further in this report.

The combinations of the energy conserving systems that are found to be cost effective into a complete citrus processing plant results in a Combined system. A Combined system would consist of all five operational units and possibly a separate energy subsystem. A combined system is simply that plant configuration that results from making use of all the cost-effective energy systems for the operational units and the central energy subsystem. Since electricity can be sold back to the utility company at nondiscriminatory rates, the only relevant interactions among the operational units and subsystems of a Combined system are associated with operating practices and, possibly, with the value of cogenerated steam. These aspects of Combined systems will be further discussed in Section 7 of this report.

2.3 Components of Operational Units and Subsystems

The components from which the operational units and the energy supply subsystems were configured are listed and briefly described below. These components are the basic elements that were considered in different combinations and arrangements for the alternative systems:

- A. Evaporators: Evaporation operations may be driven with energy in the form of either heat or work, and a single evaporator module may utilize both thermally-driven stages

and mechanically-driven stages. Multiple-effect, thermally-driven evaporators and mechanically-driven evaporators of the vapor-recompression type were analyzed for use in the evaporation operational unit discussed in Section 6 of this report.

- B. Refrigeration: Refrigeration operations may also be driven with either heat or work. Thermally-driven absorption refrigeration and mechanical refrigeration were considered for the plant, as subsequently discussed in Section 6.
- C. Heat Pumps: Heat pumps are work-driven devices which function to elevate heat from a low temperature source to a higher temperature sink. A heat pump system was considered for the pasteurization operation.
- D. Thermal Storage Units: Thermal storage was examined for use in the alternative systems to mitigate any energy usage increase resulting from transient processing loads and duty cycles. However, due to the large amount of low temperature fluid effluent from the evaporation operations and the absence of any way to make economical use of the low temperature heat, thermal storage was found to have no cost-effective applications and will not be discussed further.
- E. Heat Exchangers: Waste heat boilers and fluid effluent heat recovery units are examples of heat exchangers that were utilized where appropriate in the alternative systems.
- F. Dryers: The drying operation at the Sunkist plant requires large amounts of heat at high temperatures. The effort of this study was directed toward the manner in which the heat requirements of the drying operation are met and did not explore extensive changes in the drying operation itself. The use of gas turbine and reciproc-

cating engine exhaust to provide heat for the drying operation was examined in four different system configurations, as discussed in Section 6.

- G. Heat Engines: Brayton (gas turbine), Rankine (boiler/steam turbine), and the Reciprocating heat engines were considered for use in the Central and in certain of the Modular systems and are discussed in Section 6.

3. STUDY ORGANIZATION AND METHODS

3.1 Study Task Structure

This study was designed to evaluate alternative energy utilization systems for citrus processing plants that meet the energy requirements of citrus processing in a manner that reduces overall energy usage. The study was structured so that innovative system concepts were translated into system designs that meet both the exogenous requirements, such as air pollution rules, and the internal requirements, such as processing load cycles and product quality standards. The alternative system concepts were defined and characterized in terms of their design configuration, major component specifications, predicted operating and energy usage parameters, estimated capital cost, and appropriate economic parameters. The economic parameters and the state of technological readiness for commercial application served as the criteria for evaluation of the alternative systems. This study was carried out as a set of discrete but interrelated tasks as diagrammed in Figure 6. These tasks are further defined in Table 1.

3.2 Study Methods

The methods, ground rules, and practices that were generally employed in the execution of the tasks cited in Table 1 are briefly described in the following.

Task I. Identification of Requirements and Exogenous Factors

This task was concerned with the identification and delineation of the requirements that the alternative systems must be designed to meet. These requirements included those criteria which are externally mandated, such as air pollution, wastewater standards, FDA standards regarding food processing, and safety regulations. Requirements also include internally imposed mandates such as product quality standards and plant operating practices. Exogenous factors that were assessed and considered in the design and evaluation of

Figure 6. Schematic diagram of task structure

Table 1. Tasks comprising the study

<u>TASK</u>	<u>ACTIVITIES</u>
I. Identification of Requirements and Exogenous factors	<ul style="list-style-type: none"> o Environmental rules o Government regulations o Product quality constraints o Future energy costs and availability
II. Characterization and Analysis of citrus processing operations	<ul style="list-style-type: none"> o Experimental measurements o Thermodynamic analysis
III. Synthesis of alternative systems	<ul style="list-style-type: none"> o Conceptual layout o Preliminary performance and economic analysis o Preliminary evaluation o Performance analysis o System optimization and integration
IV. Systems evaluation	<ul style="list-style-type: none"> o Economic evaluation o Impacts on plant operations o Risk assessment o State of commercial readiness

alternative systems include energy related policies, such as those of the Public Utilities Commission and the utility companies regarding industrial power generation, and future costs of electricity and fuel.

The requirements and exogenous factors that are applicable to the alternative systems considered were identified through meetings with regulatory agencies, review of published laws and rules, and information provided by equipment vendors. The future energy cost and economic projections were based on Sunkist's historical data and on the projections as published by specialists in the field. The most significant requirements are air pollution rules, and the most important exogenous factors are the future costs of capital equipment and energy. These topics are both discussed further in Section 4 of this report.

Task II. Characterization and Analysis of Citrus Processing Operations

Certain operations of citrus fruit processing in the Sunkist plant at Ontario, CA, were characterized in terms of the values of thermodynamic variables at critical points along the process flow path. The required thermodynamic variables and other parameters such as fluid flow rates and electrical power consumption were experimentally measured in the existing processes, if they were not already being measured or could not be analytically determined from well established information. Experimental measurements were made in the characterization of the evaporation, the drying, and the fruit unloading and extraction operational units. In addition, the natural gas consumed by the existing boilers for steam production was measured. The electrical power consumption at the plant's main buss is continuously metered by the utility and is recorded at fifteen minute intervals. This data was provided by Southern California Edison for use in the study. As appropriate to support the experimental characterization and the systems synthesis and design effort, process analyses were performed for the operations being considered. This analytical work consisted of applying standard

procedures of mechanical and chemical engineering analysis to the various processes and operations of the plant, and in particular to the drying and evaporation operations.

The characterization of overall plant energy usage and of electrical power consumption is discussed hereafter in Section 5. In addition, the process analyses of multiple-effect thermal evaporation and of the peel drying operation are given in Section 5.

Task III. Synthesis of Alternative Systems

Alternative energy conserving systems that meet both the operational requirements of citrus processing and the requirements identified under Task I were synthesized according to the approach previously described in Section 2. The synthesis task consisted of formulating the conceptual layout and making a preliminary assessment of performance cost for the alternative systems. For systems with promising economic and energy usage characteristics, more detailed performance analyses and system optimization were carried out. These systems are discussed in Section 6.

Task IV. Systems Evaluation

A consistent method for evaluating the alternative citrus industry energy conserving systems in economic terms has been used. The alternative energy systems are technically viable combinations of components that are synthesized according to the approach previously described. Their performance and costs are determined under identical conditions and constraints. The alternative energy systems are evaluated in terms of investment payback period and internal rate of return, which are calculated from the cost and revenue streams associated with the energy conserving systems. Those systems that rate favorably in terms of the evaluations criteria are candidates for implementation by the citrus industry if the systems are

commercially available. Systems not commercially available that show promise are candidates for developmental programs.

The economic evaluation of the alternative systems proceeded according to the following steps: first, development of the costs of acquiring and operating the systems, second, calculation of annual cash flow streams, and finally, calculation of investment payback period and internal rate of return.

Equipment costs were developed from the relevant literature and from manufacturer's quotations. Annual operating costs for the alternative systems were derived from system performance and capacity, energy costs, maintenance costs, and financial costs. In general, annual operating cost includes, but is not limited to, labor, material, taxes, energy, insurance, interest and maintenance. Most of these costs were assumed to be the same for the existing systems and the alternative energy systems. The differential annual operating cost, which includes property tax, interest, insurance, energy, and maintenance costs, were used for the economic evaluation calculations. Maintenance costs were established from equipment manufacturer's information adjusted to consider Sunkist's maintenance procedures. The economic and financial parameters required to compute payback period (PB) and internal rate of return (IRR) were derived from Sunkist's historical data. The differential cash flow relative to the baseline configuration is the basis for computing PB and IRR. Payback period and internal rate of return methods of calculation are further discussed below.

Payback Period. This method is widely used in the citrus processing industry. The payback period is the number of years it takes to recover the initial investment.

$$\text{Payback (yrs)} = \frac{\text{Investment (\$)}}{\text{Net benefit rate (\$/yr)}}$$

where net benefit rate is the difference between the energy savings and maintenance, property tax, interest and insurance costs.

Property tax, interest cost, and insurance are assumed to be dependent on the equipment investment cost. Consequently the above relation becomes

$$\text{Payback} = \frac{\text{Investment}}{\text{energy savings-maintenance}-(\text{capital cost factor} \times \text{investment})}$$

The derivation of the capital cost factor is presented in Appendix VI.

Internal Rate of Return. This criterion is widely used in all industries, although not as extensively as the payback period. It is used in conjunction with payback period in the citrus processing industry. The internal rate of return (IRR) is the discount rate that equates the present value of the future net cash flow over the system lifetime to the initial capital outlay. For this study, the lifetime of all the alternative systems was taken as 20 years. An investment may be considered favorable if the calculated return is greater than the cost of capital to the firm.

The payback period and the internal rate of return were calculated for each of the alternative systems considered in this study. These calculations for each system were based on constant costs of energy, capital equipment, and maintenance, as subsequently given in Section 5. An example of the constant-cost calculation method is given in Appendix III, and the results for each system are presented in Section 6. In addition to the constant-cost calculations, two additional economic calculations were made for only the Central cogeneration systems. These two additional calculations were based on the future cost projections given subsequently in Section 4.1. The two additional calculations for the central cogeneration systems were: (1) a determination of the internal rate of return and the payback period based on an initial capital investment in 1980 and on escalating costs of fuel and electricity for the next 20 years, and (2) a calculation of the simple payback period and internal rate of return based on an initial investment made in 1985, 1990, 1995 and 2000 using the costs of capital equipment, energy, and maintenance as they are projected to be in

each of those years according to the scenarios presented in the following Section 4.1. Note that this second additional method is simply the application of the constant cost method, but using the costs of the year in which the investment is made. The results of these economic evaluations are presented in Section 6.1, and detailed descriptions of the calculation procedures are given in the Appendices of this report.

All the calculation procedures cited above are based on steady-state, constant-load operation of the alternative systems. However, only for the central cogeneration systems, time-dependent operation of the systems under present economic parameters was considered. This was accomplished by means of a computer program that simulated on an hourly basis the operation of central cogeneration systems that are slaved to steam demand. The results of the simulation are described in Section 6.2 and an example of the computer program output is given in Appendix V.

4. ECONOMIC AND ENVIRONMENTAL FACTORS

4.1 Economic Projections

The alternative energy systems were evaluated according to the methods previously described in Section 3.2. Those systems which are now commercially available and which show favorably in terms of the economic figures of merit, i.e., payback period and internal rate of return, as calculated with today's economic parameters are candidates for near-term procurement and installation in citrus processing plants. However, with the rapid changes in energy costs that have occurred over the past several years, it is prudent to ask how the now favorable economic figures of merit will appear under future economic scenarios. To this end, projections of future costs of energy, equipment and labor were developed as described below. Those economic scenarios were used to calculate the payback period and internal rate of return for the Central cogeneration systems as if the initial capital investments were made in future years and to calculate payback and internal rate of return for 1980 investments with future costs. The escalation rates and energy prices are shown in Tables 2 and 3, respectively. The results of these economic evaluations with escalated costs are given in Section 6.2.

Electricity Cost: Electricity prices to the Sunkist plant in Ontario have increased from \$0.023/kWhr in January, 1975 to \$0.062/kWhr in June, 1980, amounting to an annual rate of increase of 21% during the five year period. This plant is serviced by Southern California Edison (SCE) who generates a greater portion of its electricity in oil-fired plants. Presently, with the difficulties associated with coal plant siting in California and the time required for plant construction, coal's contribution to electricity generation is not expected to increase significantly in the 1980-90 time frame. Likewise, with the exception of the second and third units at San Onofre, no additional nuclear plants are expected on the SCE grid by 1990.

Table 2. Annual cost escalation rate^a projections for energy, capital equipment, and maintenance labor for 1981-2000

<u>Scenario</u>	<u>1981-84</u>	<u>1985</u>	<u>1986-2000</u>	<u>Overall 1981-2000</u>
<u>Natural gas</u>				
A	25	25	16	18
B	25	9	9	11
C	17	17	14	14
<u>Electricity</u>				
A	19	19	19	19
B	19	9	9	9
C	11	11	10	10
<u>Capital Equipment</u>				
A	10	10	10	10
B	9	9	9	9
C	8	8	7	7
<u>Maintenance</u>				
A	9	9	9	9
B	9	9	9	9
C	8	8	7	7

^a These escalator rates include general inflation and real escalation of the item. General inflation is taken as 8% during 1981-85 and 7% during 1986-2000.

Table 3. Historical data and projections for prices of natural gas, electricity and diesel oil

Year	Natural Gas ^a \$/10 ⁶ Btu	Diesel Oil ^b \$/10 ⁶ Btu	Electricity ^a \$/kW-hr
<u>Historical data</u>			
1975	0.88	--	0.0229
1976	1.19	2.27	0.0250
1977	1.69	2.36	0.0267
1978	1.99	2.63	0.0340
1979	2.12	2.65	0.0380
1980	3.80	5.36	0.062
1981	3.80	7.58	0.062
<u>Projections</u>			
1982	5.94	8.39	0.085
1984	8.09	9.29	0.110
1986	9.61	10.28	0.131
1988	11.42	11.38	0.156
1990	13.57	12.60	0.185
1995	20.88	13.95	0.284
2000	32.12	15.44	0.438

a. 1975-1981 prices are actual prices paid by Sunkist in month of January.

b Diesel prices shown for reference only; they were not used for system economic calculations.

Data Resources Incorporated (DRI) projects average annual rate of change of industrial electricity price to be 14% for the 1981-1990 period and 8% during the 1990-2000 time period.(6) These estimates are slightly different from those of Science Applications Inc., (SAI) whose projections are 12.9% per year during the 1980-1985 period, 10.8% per year for 1986-1990 and 8.3% per year during the 1991-2000 time frame.(7) Both DRI and SAI show higher rates of growth in the 1980's, then decreasing toward the end of the century. In view of Sunkist's historical electricity prices, the projections in the above referenced reports, and the possibilities for capacity addition on the SCE grid, a range of projected annual rates of change of electricity prices as shown in Table 2 were adopted for the purposes of this study. These are labeled scenarios A, B and C in Table 2.

Natural Gas Cost: The price of natural gas to the Sunkist plant in Ontario increased from \$0.88 per million Btu's in January, 1975 to \$3.8 per million Btu's in January, 1980. This is an annual compounded rate of increase of 34% during the five year period. Some industry observers contend that natural gas prices will rise to match diesel fuel prices by 1985 when natural gas prices become deregulated. DRI (6) forecasts that natural gas prices will change at an average annual rate of 18% during the 1981-1990 period and 9% in the 1990-2000 time frame. Estimated values by SAI (7) show average annual rate of change of 18% in the 1980-1985 period, 16% during the 1986-1990 time frame and 11% during the 1991-2000 period. As above mentioned, Sunkist's historical prices have been slightly higher than these average values. For the three scenarios of this study, annual rates of change of 17% to 25% for the 1980-1985 period and 9% to 16% for the 1985-2000 period are projected. These projections are shown in Table 2.

Diesel Fuel Cost: Historically, diesel fuel prices on a Btu basis have been higher than natural gas prices. From January 1976 to January 1980, the price of diesel fuel delivered to the Sunkist plant in Ontario jumped from 31.6¢ per gallon to 74.5¢ per gallon, which is

an annual rate of increase of 24% during the four year period. Price projection for this fuel is accomplished by using real escalation rates of 2.7% for the for the 1980-1990 period and 3.3% for the 1991-2000 period as assumed in the SAI report.(7) General inflation rate is assumed to be 8% per year in the 1980-85 period and 7% per year during the 1986-2000 period. With these assumptions, the projected diesel prices are shown in Table 2. Diesel prices were not used for the economic calculations in this study, and they are intended to be used for reference only.

Capital Equipment and Maintenance Labor Costs: The escalation rates used in projecting capital equipment and maintenance costs were derived from the SAI report.(7) Projected escalators that were used for the economic calculations are shown in Table 2.

Special Rates for Cogeneration: Cogeneration in California will be encouraged if preferential rates are put into effect by the California Public Utilities Commission. Under such a rate structure, the utility would pay the cogenerator a price for buy-back electricity based on the incremental cost of producing electricity from new power plants; while the cogenerator would buy electricity from the utility at the same price as other industrial customers. In addition, there have been proposals to price natural gas to cogenerators at about 10% less than the price paid by utilities. These rules have not been approved at this date and the outlook for incremental pricing of cogenerated electricity is in question; hence, in this study the buy-back rate for cogenerated electricity was taken as the average rate paid for purchased electricity. However the natural gas discount for cogenerators is viewed optimistically, and was used in the economic calculations.

4.2 Atmospheric Emissions Requirements

The relevant air pollutant limitation rules are those formulated by the California South Coast Air Quality Management District (CSCAQMD) as approved by the California Air Resources Board (CARB) and the Environmental Protection Agency (EPA). The EPA does not provide specific rules, with certain exceptions, for states which are developing their own State Implementation Plan. Since California is such a state, the limitations for a specific site, such as Ontario, are embodied in the regional Air Quality Management District (AQMD) regulations. The air pollution rules in the South Coast region for equipment of the type and size being considered in this study are summarized in Table 4 in which the entries refer to the notes that appear in Appendix I.

The CSAQMD rules set explicit limits on the quantity of oxides of nitrogen and other pollutants that may be contained in any gaseous effluent that is discharged into the atmosphere. In addition, the Best Available Control Technology (BACT) as defined by the CSAQMD for specific equipment is required. However, recently enacted provisions exclude certain cogeneration projects from the absolute mass emissions limits and the New Source Review if BACT is employed. The implementation of energy systems that incorporate gas turbine (Brayton) engines and directly fired steam boilers in a cogeneration mode is not likely to be precluded by CSAQMD rules. However, the requirement of BACT will increase the capital cost of certain energy systems.

There are several areas of rule-making which have specifically exempted or provided for reduced requirements for cogeneration projects. At the federal level, the Clean Air Act Amendments of 1977 specifically authorize local governments to provide for the mitigation of the air quality impact of cogeneration projects by providing regional growth increments in the state implementation plan. This policy is carried through the California Air Resources Board (CARB) rules and the South Coast Air Management District (SCAQMD) regulations. A recent rule by the Federal Energy Regulatory Commission

(FERC) exempts cogeneration projects of less than thirty megawatts from federal and state utility regulations. The FERC rule also orders utilities to buy back power from a cogenerator at full avoided cost and to supply the cogenerator with power at normal rates. At the state level, California has recently passed legislation (Calif. Chapter 922 Statutes of 1979 - formerly AB524 effective January 1, 1980) which accomplishes the following:

1. Tells CARB to make an inventory of potential cogeneration projects through the utilities.
2. Tells CARB and the local air quality management districts to make estimates of emissions that would result from the cogeneration projects.
3. Instructs the CARB to make room in the California State Implementation Plan for these additional emissions.

The legislative intent of this bill is to remove air quality barriers to cogeneration projects. At the regional level, SCAQMD has included several provisions in the regulations which exempt cogeneration projects or subject them to less stringent air quality restrictions. Among these are:

1. SCAQMD rule 475 exempts electric power generating projects of less than ten megawatts from the NO_x and combustion products limits which apply to larger sources. Additionally rule 475.1 (u) includes a broad exemption specifically for cogeneration projects.
2. SCAQMD rule 1304, allows the Executive Officer to exempt resource conservation and energy projects from the requirements of New Source Review provided BACT is used.

For systems considered in this study, BACT was incorporated in the system design when required.

Table 4. Summary of air pollution rules in the CSPAQMD*
 (The numbers in parentheses refer to the entries in appendix I)

<u>System Type</u>	<u>Air Pollution Rules</u>					
	<u>NOX</u>	<u>CO</u>	<u>HC</u>	<u>SOX</u>	<u>Particulates & Contaminates</u>	<u>Others</u>
Steam boiler (100,000 lb/hr)	(1)	(2)	(3)	(10)	(5)	(7,11)
Rankine cogeneration (100,000 lb/hr of steam)	(6,13)	(2)	(3)	(10)	(5)	(7,11)
Gas turbine cogeneration (3 to 10 MW)	(5,7,8,13)	(2)	(3)	(10)	(5)	(11)

*California South Coast Air Quality Management District

5. CITRUS PLANT CHARACTERIZATION AND PROCESS ANALYSES

5.1 Overall Plant Energy Usage and Economic Parameters

The operations of citrus processing are performed by subsystems within the processing plant that are referred to as operational units. The forms of energy distributed among the five operational units of the present Sunkist plant at Ontario, CA are shown in Figure 1. To process 600,000 tons of fruit annually, the entire plant requires about 51 million kilowatt hours per year of electricity and about 12 million therms* per year of thermal energy that is fired on-site to provide heat for steam generation and drying operations. The thermal and electrical energy demand of individual operations within the plant are given in Table 5. Note that 36% of the thermal energy is used for drying while 64% is for steam generation.

The plant parameters and energy costs that were used as appropriate in the constant cost evaluation of all the alternative energy systems are shown in Table 6. These costs and plant parameters were taken as constant for an economic evaluation of all the alternative systems as previously described in Section 3.2 - System Evaluation. The parameters and costs of Table 6 are currently valid for the Sunkist plant at Ontario. For economic evaluation based on constant costs, any electricity produced by the alternative systems was valued at the average rate paid for electricity. Thus, electrical power generated by the alternative systems either displaced some portion of the power that would otherwise be purchased or it was sold to the utility, and any electricity generated in excess of plant demand was sold to the utility at the same average rate that the utility charges for purchased power. Since the rate is the same in all cases, it is not necessary to make a distinction for the constant cost evaluation. Any steam produced by an alternative energy system displaces a corresponding quantity of steam generated

*One therm = 100,000 Btu

Table 5. Annual energy usage by operation Sunkist Growers
Orange Products Division, Ontario, CA
(Typical values for 600,000 tons of fruit)

<u>Electrical power</u>		
	<u>Usage</u>	
<u>Operation</u>	<u>10⁶ kW-hr</u>	<u>% of total</u>
Drying	12	23
Evaporation	619	13
Refrigeration	8.3	16
Canning & mixing	13	26
Extraction & fruit handling	5.6	11
Buildings (lighting, HVAC)	5.4	11
Total	51	100

<u>Thermal energy</u>		
	<u>Usage</u>	
<u>Operation</u>	<u>10⁶ Therms</u>	<u>% of total</u>
Drying	4.3	36
Boilers	7.7	64
Total	12	100

<u>Steam consumption</u>		
<u>Operation</u>	<u>10⁶ lb</u>	<u>% of total</u>
Evaporation	207	36
Pectin plant	124	21
Pasteurizing, Canning, heating	248	43
Total	580	100

Table 6. Plant parameters and energy costs
(Typical values, Sunkist OPD Plant,
Ontario, CA)

Plant operating time, hrs/yr	6,024
Dryer operating time, hrs/yr	4,500
Fruit processing load, tons/yr	600,000
Steam usage, lbs/yr	580×10^6
Electricity consumption, kW-hrs/yr	51×10^6
Average electricity cost, \$/kW-hr	0.06
Average electricity credit rate ^a , \$/kW-hr	0.06
Natural gas cost, \$/therm ^b	
Normal users rate	0.38
Cogeneration rate	0.35
Fuel oil cost ^c , \$/therm	0.758
Total steam & electricity cost ^d , \$/yr	6.0×10^6

^aCalifornia cogeneration rate, January, 1981

^b1 therm = 10^5 Btu

^cJanuary, 1981

^dCalculated with \$0.38/therm

by the existing boilers. Hence, steam from the alternative energy systems is valued at the cost of production by the existing boilers, up to the entire annual plant steam usage of 580 million pounds per year. Any steam in excess of the annual plant consumption is wasted and is of no value.

The Federal Energy Regulatory Commission (FERC) has adopted the criteria that the sum of the electrical energy and one-half of the useful thermal energy from a cogeneration system must equal or exceed 42.5% of the fuel energy in order for a cogeneration system to qualify for special considerations by public utility companies. Among the special considerations that may be extended to cogenerators is a reduced rate for natural gas consumed by qualifying facilities. For purposes of this preliminary study the cogeneration rate for natural gas was taken as \$0.35/therm, as shown in Table 6.

Plant Energy Usage Cycles. The Sunkist plant in Ontario, CA typically processes about 500,000 to 600,000 tons of fruit per year. The actual plant operating cycle has a seasonal period, a weekly period, and a daily period. The seasonal periods of fruit processing load, of total plant firing in Btu's, and of total plant electricity consumption are shown in Figure 7. The weekly period of the plant operating cycle is illustrated in Figures 8 and 9, wherein the average daily fruit processing load, the total natural gas consumption, and the total electricity consumption are shown for the month of March, 1979. The hourly variation of natural gas consumption by the steam boilers is shown in Figure 10 for a representative week in the on-season and for a representative week in the off-season. Those representative weeks were developed from gas consumption measurements taken in 1980 and 1981. As previously mentioned in Section 3.2, Southern California Edison made available their continuously metered electrical power data that were taken at the plant's main buss. These data were used in the simulation computer program for the central cogeneration systems and an example is given in Appendix V. Corresponding data are also given in Appendix V for steam boiler energy usage.

Figure 7. Seasonal variation of fruit load, thermal energy usage, and electricity usage at the Sunkist plant at Ontario, CA for 1979.

SUNKIST GROWERS, INC., ORANGE PRODUCTS DIVISION
FRUIT & GAS CONSUMPTION PROFILES

Figure 8. Weekly variation of thermal energy usage with fruit load at the Sunkist plant in Ontario, CA

SUNKIST GROWERS, INC., ORANGE PRODUCTS DIVISION
FRUIT & POWER LOADING PROFILES

Figure 9. Weekly variation of electricity consumption with fruit load at Sunkist plant in Ontario, CA

5.2 Energy Usage in Fruit Conveying and Juice Extraction

The fruit unloading, conveying, and juice extraction operation was characterized by measuring the electricity usage of the electric motors that drive the operation. The flow of fruit through this operation is shown in Figure 11, and the electrical power consumption of each part of the operation is shown in Figure 12. A more detailed breakdown of the electrical power consumption is shown in Table 7, which is keyed by electric motor number to Figure 11. The rated fruit handling capacity of the operation is 36 tons per hour. A significant finding of this measurement task is that the electrical power consumption of the operation is only 2% lower when running with no fruit than when running at rated capacity. This information has been used in revising operating procedures.

5.3 Energy Usage of Thermal Multi-effect Juice Evaporation

The citrus processing industry is currently using steam-driven evaporators of from four to six effects. The heat source for those evaporators is steam that is throttled to atmospheric pressure, and cooling tower water serves as the heat sink at the condenser. A typical citrus industry evaporator installation is made in modules of 40,000 lb/hr of evaporation capacity. The motive steam required by evaporators of from four to eight effects to provide 40,000 lbs/hr of evaporation is shown in Figure 13. The steam economy in pounds of water evaporated per pound of motive steam is also shown in Figure 13. A detailed mass and energy balance for a multi-effect evaporator is given in Appendix VII.

5.4 Peel Dryer Process Characterization and Analysis

The citrus peel, seeds, and pulp from the juice extraction operation are conveyed to a section of the plant called the "Feed Mill," where they are converted into a valuable cattle feed. A wet peel surge bin provides storage capacity to stabilize the peel processing operations. The peel, seeds, and pulp are ground with a

BOILER THERMAL PROFILES

Figure 10. Hourly variation of boiler fuel consumption for the Sunkist plant at Ontario, CA

1. No. SCALE UNLOADING BELT	12. LINE No. 4 - WASHER RECIRCULATING PUMP	25. EXTRACTOR No. 6
2. No. SCALE ROLLER ELEVATOR	14. LINE No. 4 - WASHER ELEVATOR	26. So. REFUSE SCREW
3. No. SCALE HIGH ELEVATOR	15. LINE No. 4 - WASHER ROLLER	27. LINE No. 4 - PEEL REC. ROLLERS
4. No. SCALE SAMPLER	16. LINE No. 4 - GRADING BELT	28. LINE No. 4 - JUICE PUMP
5. E.W.M. TOP BELT	18. LINE No. 4 - FRUIT LIFT	30. FINISHER No. 6 BANK No. 1
6. WEST BIN TOP BELT	19. LINE No. 4 - E/W BELT	34. REFUSE PULP SCREW
7. No. 1 DRAIN OUT BELT	20. LINE No. 4 - SURGE BIN BELT	35. SECONDARY FINISHER JUICE PUMP
8. So. 48 INCH BELT	21. LINE No. 4 - ROLLER CONVEYOR	37. WESTFALIA FEED PUMP
9. So. 48 INCH ROLLERS	22. LINE No. 4 - EAST SIZER BELT	38. WESTFALIA
10. So. 48 INCH WASHER FEED BELT	23. LINE No. 4 - SIZER ROLLER	40. WESTFALIA SLUDGE PUMP
11. LINE No. 4 - WASHER PADDLE	24. LINE No. 4 - EXTRACTOR FEED/RETURN BELT	41. RETURN ELEVATOR
		42. FEED PUMP TO EVAPORATOR

Figure 11. Flow of fruit through the unloading, conveying and juice extraction operation

Figure 12. Electrical power consumption of the unloading, conveying, and juice extraction operation

Table 7. Electrical power consumption in the fruit conveying and juice extraction operation

MOTORS			LOAD CURRENTS, AMPERES					POWER	AVG.	KWH $\bar{S}$ FRUIT-LOADING
NO.	HP	FLA	1	2	3	4	AVG	CONSUMPT. KWH/HR.	KWH RATED KWH	KWH $\bar{C}$ FRUIT-LOADING
1	3	4.3	4.5	4.0*	4.4	4.3	4.3	3.08	1.0	0.91
2	3	4.3	2.5	2.2*	2.4	2.4	2.4	1.72	0.56	0.92
3	3	4.3	2.8	2.7*	3.8	3.8	3.3	2.37	0.72	0.77
4	1	1.8	1.0	1.0	1.0	1.0	1.0	0.72	0.56	1.0
5	7.5	10.8	8.5	8.0*	8.5	8.0	8.2	5.88	0.76	0.96
6	7.5	10.5	7.0	6.5*	7.5	7.0	7.0	5.02	0.67	0.9
7	5	7	4.6	4.6	4.8		4.6	3.3	0.66	
8	3	4.5	4.2*	4.0	4.3	4.6	4.3	3.08	0.95	0.98
9	3	4.3	2.4*	2.5	2.5	2.4	2.4	1.72	0.56	0.96
10	3	4.3	3.1*	3.2		3.4	3.2	2.29	0.74	0.94
11	1.5	2.2	1 *	1		1.0	1.0	0.72	0.45	1.0
12	7.5	10	9 *	7.0		7.0	7.6	10.9	0.76	1.28
14	1	1.8	1.6	1.2	1.2	1.2	1.3	0.93	0.72	
15	1.5	2.3	1.7	1.6		1.6	1.6	1.15	0.70	
16	3	4.8	4.1	4.2		4.1	4.1	2.94	0.85	
17	3	4.8	3.8	3.8		3.8	3.8	2.72	0.79	
18	2	3.7	1.8	1.7		1.8	1.8	1.29	0.49	
19	2	3.7	2.3	2.2		2.4	2.3	1.65	0.62	
20	2	3.4	3.4	3.0		2.8	3.0	2.15	0.88	
21	3	4.8	3.2	3.0		2.8	3.0	2.15	0.62	
22	15	20	9 *	9.5		8.5	9.0	6.45	0.46	1.0
23	1.5	2.3	2.1*	2.2		2.1	2.1	1.51	0.91	0.95
24	3	4.5	3.1*	3.4		3.1	3.2	2.29	0.71	0.97
25	5	7	6	6		5.5	5.8	54.06	0.83	
26	5	7	4.6*	4.5		4.2	4.4	3.15	0.63	1.04
27	1/3	0.65	0.5	0.5		0.5	0.5	0.35	0.77	
28	3	4.6	3.2	3.2		3.0	3.1	4.44	0.67	
30	10	13.5	10 *	9		9.5	9.5	27.25	0.70	1.08
34	3	4.5	2.2	2.2		2.2	2.2	1.57	0.49	
35	7.5	9.5	8.5	8.0		8.0	8.1	5.81	0.85	
37	5	7	4 *	3.8		3.8	3.8	2.72	0.54	1.05
38	40	50	11 *	12.5		12.0	11.9	8.53	-	
40	1	1.5	1.4*	1.8		1.8	1.6	1.15	1.07	0.78
41	1.5	2.3	1.6	1.6		1.6	1.6	1.15	0.70	
42	5	7.3	6	6		6.2	6.1	4.37	0.83	

$\bar{x} = 0.69$

$\bar{x} = 0.98$

** $\bar{S}$ - without

$\bar{C}$ - with

* No Fruit Loading

Figure 13. Steam requirements of multi-effect, forward flow evaporators for 40,000 lb/hr evaporation capacity

metered amount of calcium hydroxide to coagulate the pectin. The ground peel is then pressed to yield press cake and liquor. The press liquor is pumped to the waste heat evaporator to be concentrated. The press cake (70 to 80% moisture) is fed to the peel dryer to produce a dry product (8-10% moisture). The concentrated press liquor may be sold separately, or it may be mixed with the wet feed to the peel dryer, thus increasing the yield of dry product. The typical dryer is a rotary drum with an oil or gas fired furnace supplying hot gas to the drum. The wet peel is fed into the hot end of the drum in direct contact with the combustion products of the fuel. The moisture of the dried peel is controlled by monitoring the temperature of the dryer exhaust gases. The exhaust gas temperature is used to control the firing rate of the dryer furnace. The furnace burner is designed to maintain the proper air/fuel ratio over the firing rate range of operation.

A single pass rotary drum dryer/waste heat evaporator system is in operation at the Sunkist plant in Ontario, CA. This system is shown schematically in Figures 14 and 15. The dryer/waste heat evaporator combination represents a significant effort toward energy conservation by utilizing the heat absorbed by the water evaporated from the moist peel inside the dryer to subsequently provide the heat required to concentrate the liquor that is pressed from the peel prior to its entering the dryer. The existing dryer/waste heat evaporator system was characterized to enable alternatives to the presently used furnace to be examined as a source of hot gas for the dryer. The system parameters which are required include solid material flow, gas flow, gas temperatures, and the moisture content of the solid and gas at both the entrance and the exit of the drum. These parameters were developed from experimental measurements of temperatures, material feed rates, moisture content, combustion stoichiometry, and fuel flow. The calculation procedures are given in Appendix VIII, and the system parameters are summarized in Table 8.

DESCRIPTION
<p>DRYER - 60,000 lb./hr. Evaporation</p> <p>1. Fuel</p> <p>2. Air</p> <p>3. Peel</p> <p>4. Meal</p> <p>5. Exhaust Gas</p>
<p>WASTE HEAT EVAPORATOR - 60,000 lb./hr.</p> <p>6. Press Liquor</p> <p>7. Conc. Press Liquor</p> <p>8. Black Water</p> <p>9. Clean Condensate</p> <p>10. Vapors to Condensor</p> <p>11. Stack Gas</p>

DRYER - WHE SYSTEM

Figure 14. Diagram of existing dryer/waste heat evaporator system

Figure 15. Schematic of dryer furnace and drum

Table 8. System specifications and performance parameters for the existing Peel dryer/Waste heat evaporator system

DRYER FURNACE

Fuel	Natural Gas
Heat content (HHV), Btu/lb	20,000
Rate, lb/hr	4,255
Heat input, 10^6 Btu/hr	85.1
Heat loss, % Fuel Heat	2
Air	
Rate, lb/hr	73,470
Air to Fuel mass ratio	17.3
Exhaust	
Rate, lb/hr	77,730
Heat output, 10^6 Btu/hr	83.4
Humidity, lb DA/lb WV	0.114

DRYER DRUM

Evaporation, lb/hr	60,000
Air leakage, lb/hr	16,290
Drum entry temperature, °F	1,065
Feed Peel	
Temperature, °F	60
Moisture, %	77
Rate, lb/hr	80,000
Product Peel	
Temperature, °F	200
Moisture, %	8
Rate, lb/hr	20,000
Exhaust	
Temperature, °F	260
Flow, actual ft ³ /min	58,710
Humidity, lb DA/lb WV	0.79
Wet bulb, °F	185
Mass flow to Waste heat evaporator, lb/hr	154,030

WASTE HEAT EVAPORATOR

Evaporation, lb/hr	60,000
Liquor feed, lb/hr	75,000
Concentrated product output, lb/hr	15,000
Water condensed from dryer exhaust, lb/hr	36,030
Stack gas from dryer exhaust, lb/hr	118,000

WV is water vapor

DA is dry air

HHV is higher heating value

6. ALTERNATIVE SYSTEMS FOR CITRUS PROCESSING - CONFIGURATION, PERFORMANCE, AND ECONOMICS

6.1 System Concepts Considered

Alternative systems for the citrus processing operations were developed according to the technical approach and by means of the methods previously discussed in Sections 2 and 3 of this report. Those systems are given in Table 9 according to system type and processing operation. The system specifications, performance parameters and energy usage are given in the following discussion for each of the systems shown in Table 9. Those systems with decided operational drawbacks or which did not reduce overall energy usage were not carried through the economic evaluation.

6.2 Central Cogeneration Systems

Central cogeneration systems supply both electricity and steam to distribution systems for use in operations throughout the plant, as was previously illustrated in Figure 2. Each of the central cogeneration systems previously shown in Figure 3 were considered for use in the Sunkist Orange Products Division plant. These systems were configured to meet the air pollution rules of the CACAQMD* and to provide steam as 40 PSIA saturated vapor for distribution within the plant. The technical characteristics of each of the central cogeneration systems are summarized in Tables 10, 11, and 12, respectively for the Brayton, Rankine, and Reciprocating engine systems. The system configurations are based on components and hardware that are commercially available. Hence, they are not of precisely the same electrical generation capacity, which is of no consequence in the evaluation of the systems. The economic benefit and energy use reduction of the systems are lost if they are sized or operated so as to waste steam.

*California South Coast Air Quality Management District

Table 9. Alternative systems considered in this study

CENTRAL SYSTEMS

Cogeneration systems for Plant Electricity and Steam

- o Brayton (gas turbine) engine/Exhaust heat boiler
- o Rankine (boiler/steam turbine)
- o Reciprocating engine/Waste heat recovery

MODULAR SYSTEMS

Peel Drying Operation

- o Parallel Brayton engine systems
- o Parallel Reciprocating engine system
- o Simple Series Brayton engine system
- o Brayton engine/Afterburner system

Evaporation Operation

- o Thermal evaporator/Steam turbine system
- o Dual-mode evaporator

Pasteurization Operation

- o Heat pump pasteurization system

Refrigeration Operation

- o Dual-mode refrigeration

Table 10. System specifications and performance parameters
for Central Brayton cogeneration
(60°F, Sea level)

Gas turbine rated continuous power output, kW(e)	3,200
Engine heat rate, Btu/kW-hr	12,000
Fuel energy input to engine, 10^6 Btu/hr	38.4
Engine heat loss, 10^6 Btu/hr	0.5
Engine exhaust temperature, °F	950
Energy in engine exhaust, 10^6 Btu/hr	27.0
Waste-heat boiler efficiency, %	65
Heat to boiler exhaust, 10^6 Btu/hr	9.5
Heat transferred to steam, 10^6 Btu/hr	17.5
Steam production rate, lb/hr	17,100
Boiler feedwater temperature, °F	175
Enthalpy of feedwater, Btu/lb	143
Gear box efficiency, %	98.5
Generator efficiency, %	95
Net electrical power output, kW(e)	3,060
Steam to plant processes:	
Steam pressure, PSIA	40
Steam temperature, °F	267
Steam quality, %	100
Enthalpy, Btu/lb	1,170

Table 11. System specifications and performance parameters
for Central Rankine cogeneration
(Two 40,000 lb/hr boilers/one steam turbine unit)

Boiler size, lb/hr	80,000
Boiler exit steam temperature, °F	750
Boiler steam pressure, PSIA	650
Condensate return fraction	0.90
Condensate temperature, °F	185
Make-up water temperature, °F	90
Boiler feedwater temperature, °F	175
Enthalpy increase of steam across boiler, Btu/lb	1,229
Boiler efficiency, %	75
Fuel energy input to boiler, 10 ⁶ Btu/hr	131
Steam turbine efficiency, %	65
Turbine exhaust pressure, PSIA	40
Isentropic enthalpy drop across turbine, Btu/lb	264
Turbine power output, kW	4,020
Water pump efficiency, %	70
Pumping power, kW	60
Gearbox efficiency, %	98.5
Generator efficiency, %	95
Net electrical power output, kW(e)	3,760
Steam to plant processes:	
Pressure, PSIA	40
Temperature, °F	267
Quality, %	100
Enthalpy, Btu/lb	1,170

Table 12. System specifications and performance parameters
for Central Reciprocating engine cogeneration
(One 1254 kW unit)

Engine electrical power output, BHP	1,770
Engine speed, RPM	600
Engine heat rate, Btu/HP-hr	8,000
Fuel energy input to engine, 10^6 Btu/hr	14.2
Engine heat loss, 10^6 Btu/hr	1.1
Engine exhaust temperature, $^{\circ}\text{F}$	885
Energy in engine exhaust, 10^6 Btu/hr	4.3
Engine efficiency (heat to work), %	31.8
Engine cooling (jacket, intercooler, lube oil), 10^6 Btu/hr	4.3
Boiler exit temperature, $^{\circ}\text{F}$	300
Heat transferred to steam, 10^6 Btu/hr	2.3
Steam production rate, lb/hr	2,200
Boiler feedwater temperature, $^{\circ}\text{F}$	175
Enthalpy of feedwater, Btu/lb	145
Generator efficiency (direct drive)	95
Net electrical power output, kW	1,254
Steam to plant processes:	
Pressure, PSIA	40
Temperature, $^{\circ}\text{F}$	267
Quality, %	100
Enthalpy, Btu/lb	1,170

However, that problem is likely to arise only with the Rankine system, whose firing rate would have to follow the plant's steam demand. As shown in Tables 10, 11, and 12, the steam production and the engine heat rates of the systems differ widely, reflecting their basic differences in system thermodynamics.

The installed capital costs of the systems are shown in Tables 13, 14, and 15. These cost estimates are derived from equipment costs provided by suppliers and manufacturers and from preliminary estimates of installation, plant modifications, and other such cost items. The costs were developed for systems assembled from specific components that are currently available from manufacturers and suppliers.

The economic characteristics of the central cogeneration systems are shown in Tables 16, 17, and 18, respectively for the Brayton, Rankine, and Reciprocating engine systems. These calculations were carried out using the constant-cost method given in Section 3.2 and with the costs and parameters given in Table 6. An example economic calculation is given in Appendix III. The cogeneration systems were assumed to operate at their design capacities of electricity and steam production for 6,024 hours per year. The resulting energy costs are shown in Tables 16, 17, and 18 for each of the three cogeneration systems. The electrical generation capacity, the total installed capital cost, the maintenance cost, and the payback and internal rate of return are also given for each of the systems. None of the systems supply both the plant's entire annual electricity and steam demand; hence, supplementary firing of existing steam boilers may be required and electricity may be purchased, depending on the system type and capacity. However, the total energy cost with each of the cogeneration systems is less than that of the existing plant. The resulting total energy cost reduction relative to the existing plant's total energy cost is shown in Tables 16, 17, and 18 for each system. The simple capital payback period and the internal rate of return (IRR) were calculated from the capital cost and the net cost savings after paying for maintenance and capital use. The Rankine and Brayton systems are roughly equivalent in terms

Table 13. Capital cost breakdown for Central Brayton
cogeneration system

3060 kW

<u>Cost Item</u>		<u>\$1000</u>
Energy conversion unit		980
Turbine-generator unit with accessories and controls	780	
Heat recovery boilers	200	
Generator substation & connections		117
Installation (foundation, piping, wiring, etc.)		412
Automatic monitoring & control system		<u>84</u>
Subtotal		1,593
Engineering and Supervision (10%)		<u>159</u>
Total cost of installed system		1,752
Installed cost per unit capacity	\$573/kW	

Table 14. Capital cost breakdown for Central Rankine
cogeneration system

3760 kW

<u>Cost Item</u>		<u>\$1000</u>
Energy conversion unit		940
Turbine-generator unit with accessories and controls	490	
High pressure boiler	450	
Generator substations & connections		117
Installation (foundation, piping, wiring, etc.)		450
Automatic monitoring & control system		<u>84</u>
Subtotal		1,591
Engineering and supervision (10%)		<u>159</u>
Total cost of installed system		1,750
Installed cost per unit capacity	\$465/kW	

Table 15. Capital cost breakdown for Central
Reciprocating engine cogeneration system

600 RPM/3762 kW
(Three 1254 kW Units)

<u>Cost Item</u>	<u>\$1000</u>
Energy conversion units	2,475
(3) Engine-generator units with accessories and controls	
(3) Heat recovery boilers	
Generator substation & connections	117
Installation (foundation, piping, wiring, etc.)	1,240
Automatic monitoring & control system	<u>150</u>
Subtotal	3,983
Engineering and supervision (10%)	<u>398</u>
Total cost of installed systems	4,381
Installed cost per unit capacity	\$1165/kW

Table 16. Economic characteristics of Central Brayton cogeneration system

Electrical generation capacity, MW	3.06	6.0	9.0	12.0	15
Capital, 10 ⁶ \$	1.75	3.44	5.2	6.9	8.6
- - - - - A n n u a l C o s t s, 10 ⁶ \$ - - - - -					
Fuel cost					
Cogeneration firing ^a	0.774	1.52	2.28	3.04	3.79
Auxillary Boiler firing ^b	2.42	1.92	1.40	0.892	0.38
Purchased electricity cost	1.95	0.89	-0.193	-1.28	-2.36
Total energy cost	5.14	4.32	3.49	2.65	1.81
Total energy cost reduction ^c	0.86	1.68	2.51	3.35	4.19
Maintenance cost (\$.0022/kW-hr)	0.04	0.08	0.12	0.16	0.20
Payback ^d /IRR ^{d,e} , yrs/%	2.6/38				

^aNatural gas @ current cogen. rate of \$.35/therm, January, 1981.

^bNatural gas @ std. rate of \$.38/therm, January, 1981.

^cRelative to present system shown in Table .

^dCapital cost factor of 0.0869.

^eInternal Rate of Return before income taxes.

Table 17. Economic characteristics of Central Rankine cogeneration system

Electrical generation capacity, MW	1.88	2.82	3.76	4.5	4.7
Capital, 10 ⁶ \$	0.875	1.31	1.75	2.09	2.19
- - - - - A n n u a l C o s t s, 10 ⁶ \$ - - - - -					
Fuel cost					
Cogeneration firing ^a	1.38	2.07	2.76	3.31	3.46
Auxillary Boiler firing ^b	1.72	1.11	0.497	0.016	None
Purchased electricity cost	2.38	2.04	1.7	1.43	1.36
Total energy cost	5.48	5.22	4.96	4.76	4.82
Total energy cost reduction ^c	0.52	0.78	1.04	1.24	1.18
Maintenance cost (\$0.0094/kWhr)	0.11	0.16	0.212	0.255	0.266
Payback ^d /IRR ^{d,e} , yrs/%	2.6/38				

^aNatural gas @ current cogen. rate of \$.35/therm, January, 1981.

^bNatural gas @ std. rate of \$.38/therm, January, 1981.

^cRelative to present system shown in Table .

^dCapital cost factor of 0.0869.

^eInternal Rate of Return before income taxes.

Table 18. Economic characteristics of Central Reciprocating engine cogeneration system

	<u>600 RPM Engine</u>				
Electrical generation capacity, MW	1.2	3.76	6.0	8.4	12.0
Capital, 10 ⁶ \$	1.40	4.38	6.99	9.79	14.0
	- - - - - A n n u a l C o s t s , 10 ⁶ \$ - - - - -				
Fuel cost	0.271	0.851	1.36	1.90	2.71
Cogeneration firing ^a					
Auxillary Boiler firing ^b	2.87	2.73	2.61	2.48	2.29
Purchased electricity cost	2.63	1.70	0.89	0.024	-1.28
Total energy cost	5.77	5.29	4.86	4.4	3.72
Total energy cost reduction ^c	0.23	0.714	1.14	1.60	2.28
Maintenance cost (\$.0049/kW-hr)	0.035	0.111	0.177	0.248	0.354
Payback ^d /IRR ^{d,e} , yrs/%	<hr/> 19/0.5 <hr/>				

^aNatural gas @ current cogen. rate of \$.35/therm, January, 1981.

^bNatural gas @ std. rate of \$.38/therm, January, 1981.

^cRelative to present system shown in Table

^dCapital cost factor of 0.0869.

^eInternal Rate of Return before income taxes.

of payback and IRR; however, the Reciprocating engine system is decidedly less economically attractive.

The economic projections of Section 4.1 as given in Table 2 were used to calculate the payback and internal rate of return with escalating costs of fuel, electricity, and maintenance, based on a 1980 capital investment. The results of this calculation are shown in Table 19 for the Brayton, Rankine, and Reciprocating engine systems. The escalating-cost evaluation gives more favorable economic figures of merit than the constant-cost evaluation because, for all three scenarios, energy costs are projected to rise more rapidly than capital costs. The methods used for the escalating-cost calculation of payback and internal rate of return are given in Appendix IV.

In addition to the above described economic evaluation method, the cost projections of Table 2 were used to calculate payback and internal rate of return as if the initial capital investment were made in future years. The constant-cost calculation method was used with the costs of capital, energy, and maintenance as they are projected to be in the future years of 1985, 1990, 1995 and 2000. The results of this calculation are given in Table 20.

Both the results of Table 19 and those of Table 20 show that Brayton and Rankine cogeneration systems will continue to show favorably in terms of payback and internal rate of return for all three scenarios of Table 2. In contrast, the Reciprocating engine systems is more sensitive to the differences among the future economic scenarios, and for Scenario C beyond the year 1990, it does not produce a net savings to pay off the capital investment.

A computer code was developed and utilized to simulate the hourly operation of the central cogeneration systems when slaved to the plant's steam element. The utility rate schedules for the Sunkist plant at Ontario, CA was employed to calculate the energy costs of operating the plant both without and with Brayton cogeneration systems over steam and electrical profiles as determined

Table 19. Economics of Central cogeneration systems under escalating costs of fuel, electricity and maintenance for 1980 capital investment

	<u>Capacity, kW</u>	<u>Initial Capital, 1980\$ in millions</u>	<u>Payback period, yrs</u>			<u>Internal rate of return %</u>		
			<u>Scenario</u>			<u>Scenario</u>		
			<u>A</u>	<u>B</u>	<u>C</u>	<u>A</u>	<u>B</u>	<u>C</u>
Brayton	3060	1.75	2.0	2.0	2.2	94	90	78
Rankine	3760	1.75	2.0	2.0	2.2	98	95	81
Reciprocating	3762	4.39	6.7	7.3	20.	29	19	0

Table 20. Economic evaluation for central cogeneration systems using constant costs of year of investment per cost projections*

Year of Investment	Scenario	Brayton			Rankine			Reciprocating		
		Capital ¹	PB ²	IRR ³	Capital ¹	PB ²	IRR ³	Capital ¹	PB ²	IRR ³
1985	A	2.82	1.8	>50.	2.82	1.7	>50.	7.07	7.1	11.
	B	2.69	2.0	50.	2.69	1.9	50.	6.75	13.6	4.
	C	2.57	2.5	40.	2.57	2.4	49.	6.45	35.1	< 1.
1990	A	4.54	1.1	>50.	4.54	1.0	>50.	11.4	4.9	20.
	B	4.14	2.0	50.	4.14	1.9	50.	10.4	13.5	4.
	C	3.61	2.3	48.	3.61	2.2	48.	9.05	-	-
1995	A	7.31	0.7	>50.	7.31	0.6	>50.	18.3	2.4	49.
	B	6.37	2.0	50.	6.37	1.9	50.	16.0	13.6	4.
	C	5.06	2.2	48.	5.06	2.3	48.	12.7	-	-
2000	A	11.8	0.4	>50.	11.8	0.4	>50.	29.5	1.3	>50.
	B	9.81	2.0	50.	9.81	1.9	50.	24.6	13.4	4.
	C	7.09	2.3	48.	7.09	2.3	48.	17.8	-	-

*Cost projections per Table 2 of this report.

¹Capital in 10⁶\$. ²Payback in years. ³Internal rate of return in %.

by measured boiler natural gas consumption and metered electrical power demand. The steam and electrical data for a typical week during the summer "on-season" period and for another during the winter "off-season" period were used as input for the program. These data and the simulation program results are given in Appendix V. The results of the simulation program calculations indicate that the annual total energy cost reduction for a 3MW Brayton cogeneration system would be 15% greater than shown in Table 16. This increased savings is due in part to reduction of the peak demand charge incurred under the time-of-use rate schedule for electrical power purchased by the Sunkist plant at Ontario, CA. This increased energy cost savings would bring the payack period down to about 2 years instead of the 2.6 years shown in Table 16, assuming the same maintenance cost and capital cost factor.

The overall efficiency of energy use is the portion of the fuel energy that is available for use as electrical energy and process steam. Both the Rankine and Brayton systems are quite energy efficient with overall efficiencies of energy use of about 70%. However, the reciprocating engine system suffers from low heat recovery for steam generation because only the exhaust gas heat is available at a temperature high enough to raise steam at 40 PSIA. The heat from the reciprocating engine cooling jacket constitutes about 28% of the fuel energy input and is not available at a temperature high enough to be recovered for use in the central cogeneration mode, resulting in the system efficiency of energy use being only 48%. The energy usage characteristics of the three central cogeneration systems are shown in Table 21. The cogeneration systems require less high temperature heat from fuel combustion than the reference systems to provide the same amounts of electricity and steam for the plant. The reference in each case is utility generated electricity and steam produced in the plant's present boilers. In the reference cases, electricity is delivered to the plant at 33% overall efficiency and steam is raised at 75 lb/Therm. The total fuel consumption in the reference cases is the sum of the fuel energy

fired by the utility to generate electricity and the fuel energy fired on-site at the plant to raise steam in the same quantities as provided by the cogeneration systems. The Brayton cogeneration system provides steam and electricity with about 29% less fuel firing than the reference. However, the Rankine and Reciprocating engine systems show only a 10% to 12% fuel energy saving because the Rankine system has a low efficiency of electrical power generation, and the Reciprocating engine system has poor heat recovery. On the other hand, the Brayton system has a moderately high engine efficiency and good heat recovery, which combine to yield the 29% reduction of energy use.

Table 21. Energy savings for Central cogeneration systems

	<u>Rankine</u>		<u>Brayton</u>		<u>Reciprocating engine</u>	
	<u>Refer- ence</u>	<u>Cogen- eration</u>	<u>Refer- ence</u>	<u>Cogen- eration</u>	<u>Refer- ence</u>	<u>Cogen- eration</u>
Steam production rate, lb/hr	80,000	80,000	17,100	17,100	2,200	2,200
Fuel energy to steam production ^a , 10 ⁶ Btu/hr	107	131	22.8	-	2.9	-
Electrical power demand/output, kW	3760	3760	3,060	3,060	1,254	1,254
Fuel energy to power production ^b , 10 ⁶ Btu/hr	39	-	31.6	38.4	13.0	14.2
Total fuel energy consumption, 10 ⁶ Btu/hr	146	131	54.4	38.4	15.9	14.2
Energy savings, 10 ⁶ Btu/hr		15	-	16.0	-	1.7
Percent energy savings		10	-	29.4	-	10.7

^aReference case steam raised @ 75 lb/therm.

^bUtility generated electricity delivered @ 33% overall efficiency.

6.3 Citrus Peel Drying System

The peel drying operation is presently linked with a waste heat evaporator that produces molasses from peel press liquor. The waste heat evaporator (WHE) makes use of the heat content of the peel dryer drum exhaust gas. The concentration of press liquor and selected waste water streams is an essential part of the processing plant's operation. If the waste heat evaporator were not available, some means of concentrating the existing WHE feed would have to be provided; most likely a conventional four to six effect evaporator of 60,000 lb/hr capacity. The peel dryer/waste heat evaporator system was previously described in Section 5.4, and its system specifications and performance parameters were given in Table 8.

Any consideration of alternative systems for the peel drying operation must consider effects on the entire dryer/waste heat evaporator system. The moisture in the dryer drum exhaust provides most of the motive heat for the waste heat evaporator. The absolute humidity of the gas stream entering the waste heat evaporator is normally about 0.79 lb water vapor per lb of dry air, with a corresponding wet bulb temperature of 185°F. The absolute humidity of the gas stream must be above 0.7 lb water vapor per lb dry air for acceptable operation of the waste heat evaporator. The mass and energy balance calculations of Appendix VIII were used to calculate the system parameters of each of the four alternative systems for the peel drying operation that were cited in Table 9.

The furnace gas that provides the heat for the drying process in the dryer drum can be augmented or replaced by the exhaust gas of an internal combustion heat engine. The engine exhaust may be blended with the products of the furnace to be fed into the dryer drum in the parallel arrangement as shown in Figure 16a. In the series arrangement, engine exhaust containing excess air flows into an afterburner where additional fuel is injected and burned; the afterburner products are then fed into the dryer drums as shown in Figure 16b.

Figure 16a. Parallel arrangement

Figure 16b. Series arrangement

Figure 16. System configurations for peel dryer cogeneration

The system specifications and performance parameters for the Brayton (gas turbine) engine in the parallel arrangement with the dryer furnace are shown in Table 22. The Brayton engine exhaust gas contains nearly 280% excess air and, hence, has a very low humidity. However, the dryer furnace operates with about 20% excess air, giving a much higher humidity. The mass and energy balances for the Brayton engine, dryer furnace, dryer drum system were iteratively solved to find the maximum size of the Brayton engine, using typical engine parameters, that could be used without driving the dryer drum exit gas humidity below 0.72. As shown in Table 22, the allowable engine output is only 263 kW. The energy usage characteristics of this system are shown in Table 23. Due to the loss in waste heat evaporation capacity resulting from the decreased humidity of the dryer drum exit gas, the firing rate in the dryer furnace must be stepped up to increase the evaporation capacity in the dryer later to offset the loss in WHE capacity. This results in the Parallel Brayton engine peel dryer system offering no energy savings relative to the reference system that provides the same total evaporation rate and amount of electrical power. Note that, as given in Table 23, the reference system consists of the existing dryer/WHE system and utility generated electricity. The total fuel firing in the reference case is the sum of the fuel firing rate of the utility to provide 263 kW of electricity and that of the present dryer/WHE system to provide 120,000 lb/hr of total evaporation capacity. In view of this system offering no energy savings, it is not treated further.

The system specifications and performance parameters for a natural gas fired Reciprocating engine in the parallel arrangement with the dryer furnace are shown in Table 24. The same calculation method as described above was used to size the Reciprocating engine, except that, instead of allowing the dryer drum exit humidity to fall to 0.72, the humidity and the dryer drum evaporation rate were set at their normal values so that no compromise in dryer/WHE system performance was incurred. This is possible because the reciprocating engine exhaust gas contains little excess air. The resulting reciprocating engine size was found to be 870 kW. The energy savings

Table 22. System specification and performance parameters
for Parallel Brayton engine/Peel dryer system

BRAYTON ENGINE

Fuel	Natural Gas
Heat content (HHV), Btu/lb	20,000
Rate, lb/hr	188
Heat input, 10^6 Btu/hr	3.76
Heat loss, % of fuel heat	2
Air	
Rate, lb/hr	10,210
Air to Fuel mass ratio	54.3
Exhaust	
Rate, lb/hr	10,400
Heat output, 10^6 Btu/hr	2.8
Temperature, °F	910
Humidity, lb WV/lb DA	0.035
Power	
Efficiency, %	24.0
Engine work output, kW	263

DRYER FURNACE

Fuel	Natural Gas
Heat content (HHV), Btu/lb	20,000
Rate, lb/hr	4,146
Heat input, 10^6 Btu/hr	82
Heat loss, % fuel heat	2
Air	
Rate, lb/hr	71,590
Air to Fuel mass ratio	17.3
Exhaust	
Rate, lb/hr	86,140
Heat output, 10^6 Btu/hr	84.0
Humidity, lb WV/lb DA	0.114

DRYER DRUM

Evaporation, lb/hr	60,000
Air leakage, lb/hr	16,290
Feed Peel	
Temperature, °F	60
Moisture, %	77
Rate, lb/hr	80,000
Product Peel	
Temperature, °F	200
Moisture, %	8
Rate, lb/hr	20,000
Exhaust	
Temperature, °F	260
Flow, actual ft ³ /min	61,220
Humidity, lb WV/lb DA	0.722
Wet bulb, °F	183

WV is water vapor. DA is dry air. HHV is higher heating value.

Table 23. Energy savings for Parallel Brayton engine/Peel dryer system

	<u>Reference System</u>	<u>Parallel/Brayton System</u>
Evaporation rate in dryer kiln, lb/hr	60,000	66,300 ^a
Evaporation rate from dryer kiln exhaust, lb/hr	60,000	53,700 ^b
Total evaporation rate, lb/hr	120,000	120,000
Fuel energy to dryer furnace, 10 ⁶ Btu/hr	85	88
Electrical power provided, kW	263 ^c	263 ^d
Fuel energy to power production, 10 ⁶ Btu/hr	2.7 ^e	3.8 ^f
Total fuel energy consumption, 10 ⁶ Btu/hr	87.8	92.0
Energy savings, 10 ⁶ Btu/hr	-	-4.2
Percent energy savings	-	-4.8

^aDryer drum evaporation rate increased to compensate for evaporation loss in WHE.

^bWHE evaporation loss due to humidity decrease in dryer drum exhaust.

^cProvided by utility company.

^dPower generated by Brayton engine/generator.

^eUtility generated electricity delivered @ 33% overall efficiency.

^fFuel to fire Brayton engine-generator with engine exhaust heat to dryer drum.

WHE is Waste Heat Evaporator.

Table 24. System specifications and performance parameters for
Parallel Reciprocating engine/Peel dryer system

RECIPROCATING ENGINE

Fuel	Natural Gas
Heat content (HHV), Btu/lb	20,000
Rate, lb/hr	464
Heat input, 10^6 Btu/hr	9.28
Heat loss, % of fuel heat	4
Air	
Rate, lb/hr	6,960
Air to fuel mass ratio	15
Exhaust	
Rate, lb/hr	7,424
Heat output, 10^6 Btu/hr	5.94
Temperature, °F	1,034
Humidity, lb WV/lb DA	0.132
Power	
Thermal efficiency	32
Engine power output, kW	870
Electrical power output, kW	827

DRYER FURNACE

Fuel	Natural Gas
Heat content, Btu/lb	20,000
Rate, lb/hr	3,884
Heat input, 10^6 Btu/hr	77.7
Air	
Rate, lb/hr	67,187
Air to fuel mass ratio	17.3
Exhaust	
Rate, lb/hr	71,071
Heat output, Btu/hr	80.6

DRYER DRUM

Evaporation rate, lb/hr	60,000
Air leakage rate, lb/hr	16,289
Drum entry temperature, °F	1,065
Feed peel	
Temperature, °F	60
Moisture, %	77
Rate, lb/hr	80,000
Product peel	
Temperature, °F	200
Moisture, %	8
Rate, lb/hr	20,000
Exhaust to waste heat evaporator	
Temperature, °F	260
Flow, acfm	58,968
Humidity, lb WV/lb DA	0.786
Wet bulb, °F	185

WF is water vapor. DA is dry air. HHV is higher heating value
acfm is actual cubic feet per minute.

for the Parallel Reciprocating engine system is given in Table 25. As described above, the reference system and the alternative system provide the same electrical power and processing capacity, but by differing means as given in Table 25. Under this perspective, the overall reduction in firing rate is 7.3% for the Parallel Reciprocating engine system. In view of its energy savings and of its status as a commercially available system requiring little development, this system was carried through costing and economic evaluation as shown in Tables 26 and 27. As shown in Table 27, the payback and internal rate of return are 9 years and 9%. Since little improvement is likely to result from additional development of this system, it is not likely to be introduced in citrus processing plants.

Two additional peel dryer systems were considered in the series arrangement of Figure 16. The first of these series configurations to be discussed is the Simple Series Brayton engine/peel dryer system whose system specifications and performance parameters are shown in Table 28. This system configuration consists only of a large gas turbine engine and the dryer drum. The engine exhaust passes directly into the drum. Since the Brayton engine exhaust gas contains so much excess air, the requirement to maintain dryer drum exit humidity was dropped. Instead, only a dryer drum evaporation capacity of 60,000 lb/hr was required. In this system, the waste heat evaporator was discarded and replaced with a conventional multi-effect evaporator to concentrate the press liquor. The resulting energy savings relative to the reference system is given in Table 29. The net overall energy savings of 12% would not singly be reason to drop this system. However, in view of the operating problems that are likely to be associated with modulating the firing rate of a large Brayton engine to control the peel drying process and due to the large additional capital expense of installing an evaporator to replace the WHE, the Simple Series Brayton engine system is not considered further.

The above mentioned disadvantages of the simple series Brayton engine system may be addressed by using an afterburner between the gas turbine engine and the dryer drum as shown in Figure 16b.

Table 25. Energy savings for Parallel Reciprocating engine/Peel dryer system

	<u>Reference System</u>	<u>Parallel Recip. System</u>
Evaporator rate in dryer, lb/hr	60,000	60,000
Evaporator rate in WHE ^a , lb/hr	60,000	60,000
Fuel energy to dryer furnace, 10 ⁶ Btu/hr	85.1	77.7
Electrical power provide, kW	870 ^b	870 ^c
Fuel energy to power production, 10 ⁶ Btu/hr	9.0 ^d	9.3 ^e
Total fuel energy consumption, 10 ⁶ Btu/hr	94.1	87.0
Energy savings, 10 ⁶ Btu/hr	-	7.1
Percent energy savings	-	7.3

^aWaste Heat Evaporator.

^bPower provided by utility company.

^cPower generated by Reciprocating engine-generator.

^dUtility generated electricity delivered @33% overall efficiency.

^eFuel to fire Reciprocating engine-generator with exhaust to dryer drum.

Table 26. Capital cost breakdown for Parallel
Reciprocating engine/Peel dryer system

<u>870 kW</u>	
<u>Cost Item</u>	<u>\$1000</u>
Engine-generator unit with accessories and controls	394
Generator substation & connections	50
Installation (foundation, ducting, etc.)	310
Automatic monitoring control system	<u>80</u>
Subtotal	834
Engineering and supervision (10%)	<u>83</u>
Total cost of installed system	917
Installed cost per unit capacity	\$1109/kW

Table 27. Economic characteristics of Parallel Reciprocating engine/Peel dryer system

	<u>Present System</u>	<u>Parallel Recip. System</u>
Electrical generation capacity, kW	none	827
Additional capital, 10 ³ \$	none	917
	- - - - Annual Costs, 10 ³ \$ - - - -	
Fuel cost		
Cogeneration firing ^a		146
Direct firing ^b	1,450	1,330
Electricity credit		-223
Total energy cost	1,450	1,253
Energy cost reduction ^c		197
Additional maintenance cost		23
Payback ^d /IRR ^{d,e} , yrs/%		9.1/9

^aNatural gas @ current cogeneration rate of \$.35/therm, January, 1981.

^bNatural gas @ standard cost rate of \$.38/therm, January, 1981.

^cRelative to present system shown in this table.

^dCapital cost factor of 0.0869.

^eInternal Rate of Return before income taxes.

Table 28. System specification and performance parameters
for Simple Series Brayton engine/Peel dryer system

<u>BRAYTON ENGINE</u>	
Fuel	Natural Gas
Heat content (HHV), Btu/lb	20,000
Rate, lb/hr	7,089
Heat input, 10^6 Btu/hr	142
Air	
Rate, lb/hr	385,000
Air to Fuel mass ratio	54.3
Exhaust	
Rate, lb/hr	392,000
Heat output, 10^6 Btu/hr	105
Temperature, °F	910
Humidity, lb DA/lb WV	0.035
Power	
Efficiency, %	25.5
Electrical work output, kW	9,929
<u>AFTERBURNER</u>	None
<u>DRYER FURNACE</u>	None
<u>DRYER DRUM</u>	
Evaporation, lb/hr	60,000
Air leakage, lb/hr	16,289
Drum entry temperature, °F	910
Feed Peel	
Temperature, °F	60
Moisture, %	77
Rate, lb/hr	80,000
Product Peel	
Temperature, °F	200
Moisture, %	8
Rate, lb/hr	20,000
Exhaust	
Temperature, °F	260
Flow, actual ft ³ /min	154,700
Humidity, lb DA/lb WV	0.185
Wet bulb, °F	151

WV is water vapor
DA is dry air
HHV is higher heating value

Table 29. Energy savings for simple Series Brayton engine/Peel dryer system

	<u>Reference System</u>	<u>Series Brayton System</u>
Evaporation rate in dryer drum, lb/hr	60,000	60,000
Evaporation rate from drum exhaust, lb/hr	60,000	none
Evaporation rate auxillary evaporator, lb/hr	None	60,000
Total dehydration rate, lb/hr	120,000	120,000
Fuel energy to dehydrating, 10^6 Btu/hr	85 ^a	23 ^b
Electrical power provided, kW	9,929 ^c	9,929 ^d
Fuel energy to power production, 10^6 Btu/hr	103 ^e	142 ^f
Total fuel energy consumption, 10^6 Btu/hr	188	165
Energy savings, 10^6 Btu/hr		23
Percent energy savings		12.2

^aFuel to dryer furnace.

^bFuel to direct steam generation for auxilliary evaporator.

^cPower provided by utility company.

^dPower generated by Brayton engine/generator.

^eUtility generated electricity delivered @ 33% overall efficiency.

^fFuel to fire Brayton engine generator with engine exhaust heat to dryer kiln.

Additional fuel is injected into the afterburner to be burned with the excess air of the gas turbine exhaust stream. The mass and energy balances for the system were solved to find the engine size and the afterburner firing rate to give a dryer drum evaporation rate of 60,000 lb/hr and an exit humidity of 0.739. The system specifications and performance parameters for the series Brayton engine/afterburner/peel dryer system are shown in Table 30. The overall energy savings relative to the reference system is shown in Table 31. The overall reduction in firing rate is 12% for the Brayton engine/afterburner system. The reference system energy usage consists of the fuel fired by the utility to provide the same amount of electricity as the peel dryer gas turbine engine and of the furnace fuel fired in the existing peel dryer system.

The Brayton engine/afterburner system is operationally feasible since the firing rate of the afterburner can be modulated to control the peel drying process, and the waste heat evaporator is retained at full capacity since the humidity of the dryer drum exit gas is high enough. Although this is a new system concept that has never been tried in practice, the only non-commercially available component is an afterburner that will burn the excess air in the exhaust gas down to near 20%. Development of a low excess air afterburner and system integration are required before the Brayton engine/afterburner system would be commercially viable. In view of its positive energy savings and operational feasibility, the Brayton engine/afterburner system was carried through costing and economic evaluation as shown in Tables 32 and 33. As shown in Table 33, the system is projected to payback in less than 5 years with a 20% internal rate of return. If cogeneration is to be seriously considered for the drying operation, the Brayton/afterburner system is the leading candidate. And with some developmental effort, its economic characteristics may improve.

Table 30. System specifications and performance parameters for
Series Brayton engine/Afterburner/Peel dryer system

BRAYTON ENGINE

Fuel	Natural Gas
Heat content (HHV), Btu/lb	20,000
Rate, lb/hr	1,490
Heat input, 10^6 Btu/hr	29.8
Heat loss, % of fuel heat	2
Air	
Rate, lb/hr	80,910
Air to fuel mass ratio	54.3
Exhaust to afterburner	
Rate, lb/hr	82,400
Heat output, Btu/hr	22.1
Temperature, °F	910
Humidity, lb WV/lb DA	0.035
Power	
Engine thermal efficiency, %	23.9
Engine power output, kW	2,054
Electrical power output, kW	1,950

AFTERBURNER

Fuel	Natural Gas
Heat content (HHV), Btu/lb	20,000
Rate, lb/hr	3,195
Heat input, 10^6 Btu/hr	63.9
Heat loss, % fuel heat	2
Exhaust to drum entrance	
Rate, lb/hr	85,590
Heat output, 10^6 Btu/hr	84.7
Temperature, °F	0
Humidity, lb WV/lb DA	0.121

DRYER DRUM

Evaporation, lb/hr	60,000
Air leakage, lb/hr	16,290
Drum entry temperature, °F	1,069
Feed Peel	
Temperature, °F	60
Moisture, %	77
Rate, lb/hr	80,000
Product Peel	
Temperature, °F	200
Moisture, %	8
Rate, lb/hr	20,000
Exhaust to waste heat evaporator	
Temperature, °F	260
Flow, actual ft ³ /min	61,220
Humidity, lb WV/lb DA	0.739
Wet bulb, °F	183

WV is water vapor. DA is dry air. HHV is higher testing value.

Table 31. Energy savings of Series Brayton engine/Afterburner/Peel dryer system

	<u>Reference System</u>	<u>Series Brayton Afterburner system</u>
Evaporation rate in dryer, lb/hr	60,000	60,000
Evaporation rate in WHE ^a , lb/hr	60,000	60,000
Fuel energy input to dryer furnace, 10 ⁶ Btu/hr	85.1	-
Fuel energy input to afterburner, 10 ⁶ Btu/hr	-	63.9
Electrical power provided, kW	2087 ^b	2087 ^c
Fuel energy to power production, 10 ⁶ Btu/hr	21.6 ^d	29.8 ^e
Total fuel energy consumption, 10 ⁶ Btu/hr	106.7	93.7
Energy savings, 10 ⁶ Btu/hr	-	13.0
Percent energy savings	-	12.1

^aWaste Heat Evaporator.

^bPower provided by utility company.

^cPower generated by Brayton engine-generator.

^dUtility generated electricity delivered at 33% overall efficiency.

^eFuel to fire Brayton engine-generator with engine exhaust to afterburner.

Table 32. Capital cost breakdown for Series Brayton engine/Afterburner/Peel dryer system

<u>2100/kW</u>	
<u>Cost Item</u>	<u>\$1000</u>
Energy conversion unit	602
Turbine-generator unit with accessories and controls	402
Afterburner and controls	200
Generator substation & connections	117
Installation (foundation, ducting, wiring, etc.)	412
Automatic monitoring & control system	<u>84</u>
Subtotal	1,215
Engineering and Supervision (10%)	<u>122</u>
Total cost of installed system	1,337
Installed cost per unit capacity	\$686/kW

Table 33. Economic Characteristics of Series Brayton engine/Afterburner/Peel dryer system

	<u>Present System</u>	<u>Brayton/Afterburner System</u>
Electrical generation capacity, MW	none	1.95
Additional capital, 10 ⁶ \$	none	1.337
	- - - - - Annual Costs, 10 ³ \$ - - - - -	
Fuel cost		
Cogeneration firing ^a	-	469
Direct firing ^b	1,450	1,090
Electricity credit	-	-527
Total energy cost	1,450	1,032
Energy cost reduction ^c	-	418
Additional maintenance cost	-	21
Payback ^d , IRR ^{d,e} , yrs/%	-	4.8/20

^aNatural gas @ current cogeneration rate of \$.35/therm, January, 1981.

^bNatural gas @ standard rate of \$.38/therm, January, 1981.

^cRelative to present system shown in this table.

^dCapital cost factor of 0.0869.

^eInternal Rate of Return before income taxes.

6.4 Evaporation Systems

Modular Thermal Evaporator/Steam Turbine System. The Sunkist plant at Ontario, CA, presently has three multi-effect steam driven evaporators in which steam at the boiler pressure of 150 psi is throttled by pressure reducing valves or orifices to near-atmospheric pressure prior to entering the first-effect of the evaporator. The throttling valve can be replaced by a simple, single stage steam turbine-generator unit to make use of the pressure reduction to produce work. Thus, a portion of the thermodynamic availability appears as mechanical work instead of being lost in the throttling process. A steam turbine of about 500 kW power output is matched to the total steam flow of three evaporator units, each of 40,000 lb/hr capacity. This arrangement of three evaporator units downstream of a steam turbine is referred to as the Modular Thermal Evaporator/Steam Turbine system (MTE/ST). The system specifications and performance parameters for the MTE/ST system are shown in Table 34 along with those for the evaporator units without the steam turbine. In order to supply the same energy for evaporation, the MTE/ST must have a slightly higher steam flow rate than the conventional system. Due to the energy extraction by the turbine, the enthalpy of the evaporator feed steam is lower in the MTE/ST system; hence, a higher steam flow is required. The energy usage characteristics of the MTE/ST and of the reference system are shown in Table 35. The overall energy savings of the MTE/ST system is 7.7% relative to the reference system of the same evaporation capacity and with utility generated electricity in the same amount as produced by the MTE/ST. The capital cost and economic characteristics of the MTE/ST system are shown in Tables 36 and 37, respectively. The MTE/ST system does show favorably in terms of payback and IRR, but the quantity of energy saved and the cost saving are both small in comparison to the other systems being considered.

Modular Dual-mode-Evaporator system. Evaporation processes may be driven with energy in the form of either heat or work, and a single evaporator unit may include both thermally-driven and work

driven stages. Such evaporator units are referred to as dual-mode evaporators. The dual-mode evaporation systems considered here include both a mechanically-driven, vapor-recompression (MVR) evaporator unit and a multiple-effect, thermal evaporator unit in a single evaporator battery. In general, dual-mode evaporation schemes with conventional components do save energy, but their high initial capital cost has been found to result in a relatively low rate of capital return. Dual-mode evaporation is discussed in References (1) and (4).

The concept of dual-mode evaporation may be extended to include a gas turbine engine with exhaust heat recovery that is an integral component of the evaporator unit. This concept, referred to as the Modular Dual-Mode Evaporator, offers the additional energy savings of cogeneration and potential cost reductions in the integrated unit.

The modular dual-mode (MDM) evaporator concept is illustrated in the schematic diagram of Figure 17. This particular evaporator is for concentration of orange juice from natural strength (12% solids) to 65% solids. As shown in Figure 17, the MDM evaporator consists of a preheating and pasteurization section, an MVR evaporator section whose compressor is shaft driven by the gas turbine, a three-effect thermal evaporator section that is supplied with steam from the waste heat boiler, and the gas turbine engine/waste heat boiler cogeneration unit. The system is designed for a total evaporation rate of 40,000 lb/hr of which 72% is accomplished in the MVR unit and 28% in the three-effect thermal evaporator. The system is balanced so that all the steam generated by the turbine exhaust is consumed in the thermal evaporator and the pasteurizer, with a small amount of supplementary steam supplied to "fine tune" the pasteurizer.

The system parameters and specifications for the MDM evaporator are shown in Table 38. The compressor of the MVR unit operates at a 1.5:1 pressure ratio and with an efficiency of 73%. The compressor is directly shaft driven by the gas turbine engine producing 517 HP at 18% thermal efficiency. The gas turbine exhaust provides heat to raise 3926 lb/hr of steam for the three-effect thermal evaporator.

Intermediate temperatures, pressures and mass flow rates throughout the system are shown in Table 38.

The cost and energy savings of an MDME evaporator that is based on conventional components are presented in Tables 39 and 40. Without the benefit of any work to refine the system design or to develop specific components, the MDM evaporator is currently estimated to cost from 60% to 100% more than a conventional six-effect evaporator; however, the MDM evaporator would consume only 60% of the energy of the six-effect evaporator. The economic characteristics of the MDME system are shown in Table 41. With the present energy and capital costs the payback period is ten years. With further systems development of the MDME directed toward optimizing the system design and developing critical components, both the energy consumption and the capital cost of the MDME system could be reduced. The modular dual mode evaporator concept has the potential for significant energy savings while meeting industrial criteria for capital investment.

Table 34. System specifications and performance parameters for the present evaporator system and for the Modular Thermal Evaporator/Steam Turbine system

	<u>Present System</u>	<u>MTE/ST</u>
Number of evaporators, six effect units	3	3
Evaporation rate per unit, lb/hr	40,000	40,000
Boiler steam temperature, °F	366	366
Boiler steam pressure, psia	165	165
Boiler steam quality, %	97	97
Boiler steam enthalpy, Btu/lb	1,170	1,170
Steam energy to evaporation, 10 ⁶ Btu/hr	28.8	28.8
Evaporation steam requirement, lb/hr	24,600	26,100
Turbine exhaust pressure, psia	-	20
Turbine exhaust temperature, °F	-	228
Turbine exhaust quality, %	-	94
Turbine reversible work, Btu/lb	-	148
Evaporator steam pressure, psia	14.7	14.7
Evaporator steam temperature, °F	253	212
Evaporator steam quality, %	100	95
Evaporator steam enthalpy, Btu/lb	1,170	1,102
Turbine efficiency, %	-	46
Turbine power output, kW	-	520
Gearbox efficiency, %	-	98.5
Generator efficiency, %	-	95
Net electrical power output, kW	-	487
Total electrical power requirement, kW	450	450
Electrical output to plant, kW	-	37

Table 35. Energy savings for Modular Thermal Evaporator/Steam Turbine system

	<u>Reference System</u>	<u>MTE/ST</u>
Steam usage, lb/hr	24,600.	26,100.
Boiler fuel consumption ^a , 10 ⁶ Btu/hr	33.8	35.8
Electrical demand/production, kW	487 ^b	487 ^c
Fuel to electricity generation, 10 ⁶ Btu/hr	5.0 ^d	-
Total fuel energy consumption, 10 ⁶ Btu/hr	38.8	35.8
Energy savings, 10 ⁶ Btu/hr		3.0
Percent energy savings		7.7

^aSteam production @ 75 lb/therm.

^bPower provided by utility company.

^cPower generated by steam turbine-generator.

^dUtility generated electricity delivered @33% overall efficiency.

Table 36. Capital cost breakdown for Modular
Thermal Evaporator/Steam Turbine system

487 kW

<u>Cost Item</u>	<u>\$1000</u>
Energy conversion unit	
Turbine-generator unit with accessories and controls	62
Thermal evaporator monitoring & control system	15
Generator switchgear & connections	40
Installation (support, piping, wiring, etc.)	<u>100</u>
Subtotal	212
Engineering and Supervision (10%)	<u>21</u>
Total cost of installed system	233
Installed cost per unit capacity	\$478/kW

Table 37. Economic characteristics of Modular Thermal Evaporator/Steam Turbine System

	<u>Baseline</u>	<u>MTE/ST</u>
Electrical generation capacity, kW	none	490
Capital, 10 ³ \$		233
	- - - Annual Costs, 10 ³ \$ - - -	
Fuel cost		
Cogeneration firing ^a		488
Present firing ^b	500	
Electricity credit	none	-117
Total energy cost	500	371
Total energy cost reduction ^c		129
Additional maintenance cost(\$.0069/kW-hr)		21
Payback ^d /IRR ^{d,e} , yrs/%		2.7/37

^aNatural gas @ current cogeneration rate of \$.35/therm, January, 1981.

^bNatural gas @ standard rate of \$.38/therm, January, 1981.

^cRelative to Baseline shown in this table.

^dCapital cost factor of 0.0869.

^eInternal Rate of Return before income taxes.

DUAL-MODE JUICE EVAPORATOR

Figure 17. Schematic of Modular dual-mode evaporator system

Table 38. System specifications and performance parameters
for Modular Dual-mode Evaporator

MVR EVAPORATOR (Pre-evaporator in Dual-mode)

Mass Flows	
Feed rate, lb/hr	49,060
Product rate, lb/hr	19,630
Evaporation, lb/hr	29,430
Solids in feed, % by Weight	12
Solids in product, % by Weight	30
Temperatures, °F	
Feed	128
Product	141
Low side vapor	140
High side saturation	156
Compressor discharge	237
Pressures, psia	
Low side	2.89
High side	4.34
Pressure ratio	1.5
Heat content, Btu/lb	
Feed	89
Product	98
Condensate	124
Low side vapors	1,122
High side vapors	1,129
Compressor discharge	1,166
Work and Efficiencies	
Isentropic work, Btu/lb	33
Compressor work, Btu/lb	44
Compressor efficiency, %	75
Heat loss, %	0.3

MECHANICAL VAPOR COMPRESSOR

Vapor to compressor, lb/hr	29,430
Water to desuperheat, lb/hr	990
Steam to maintain temperature, lb/hr	None
Vapor to tube nests, lb/hr	30,420
Work input to compressor, Hp	509

GAS TURBINE

Gearbox efficiency, %	98.5
Gas turbine size, Hp	517
Turbine efficiency, %	18
Air/Fuel ratio	67
Fuel rate, Btu/hr (HHV)	7.3×10^6
Work heat rate, Btu/hr	1.32×10^6
Exhaust heat, Btu/hr	5.98×10^6
Fuel mass rate, lb/hr	365
Exhaust temperature, °F	848

Table 38. System specifications and performance parameters
for Modular Dual-mode Evaporator (continued)

WASTE HEAT BOILER

Steam pressure, psia	20
Heat to generate steam, Btu/lb	990
Boiler efficiency	65
Steam rate, lb/hr	3,926

PRE-HEATING - PASTEURIZING AHEAD OF MVR

Condensate/Feed Heat Exchanger	
Juice rate, lb/hr	49,060
Condensate rate, lb/hr	29,430
Temperature of juice in, °F	60
Temperature of juice out, °F	116
Temperature of condensate in, °F	156
Temperature of condensate out, °F	70
Regenerator	
Temperature of juice in, °F	116
Temperature of juice out, °F	188
Temperature of pasteurized Juice in, °F	200
Temperature of pasteurized Juice out, °F	128
Pasteurizer	
Temperature of juice in, °F	188
Temperature of juice out, °F	200
Steam used, lb/hr	595

THERMAL MULTIPLE EFFECT EVAPORATOR

Mass Flows	
Feed rate, lb/hr	19,630
Product rate, lb/hr	9,060
Evaporation, lb/hr	10,570
Solids in feed, % by weight	30
Solids in product, % by weight	65
Steam to first-effect & second	
Preheater, lb/hr	3,650
Temperatures, °F	
Feed	141
Exit first preheater	150
Exit second preheater	180
Exit first-effect	160
Exit second-effect	140
Exit third-effect (product)	110
Condensate	140

Table 39. Energy savings for Modular Dual-mode Evaporator system

40,000 lb/hr Evaporator capacity

	Conventional (six-effect)	Dual-mode MVR-Thermal
Steam usage, lb/hr	8,200.	none
Boiler fuel consumption ^a , 10 ⁶ Btu/hr	10.9	none
Gas turbine engine firing, 10 ⁶ Btu/hr	none	7.3
Electrical consumption, kW	150. ^b	50. ^b
Fuel to electricity generation, 10 ⁶ Btu/hr	1.6 ^c	0.5 ^c
Total fuel energy consumption, 10 ⁶ Btu/hr	12.5	7.8
Energy savings, 10 ⁶ Btu/hr		4.7
Percent energy savings		38.

^aSteam production @75 lb/therm.

^bPower provided by utility company.

^cUtility generated electricity delivered @33% overall efficiency.

Table 40. Capital cost breakdown for
Modular Dual-mode Evaporator

<u>Cost Item</u>	<u>\$1000</u>
Energy conversion unit	235
500 kW gas turbine engine with accessories and controls	200
Heat recovery boiler	35
MVR evaporator unit	
Compressor	170
Evaporator	350
Three-effect thermal finisher (10 ⁴ lb/hr evaporator & cooling tower)	300
Installation (foundation & ancillary components)	200
Monitoring & control system	<u>20</u>
Subtotal	1,255
Engineering and Supervision (10%)	<u>125</u>
Total cost of installed system	1,400

Table 41. Economic characteristics of Modular Dual-mode Evaporator

	<u>40,000 lb/hr Evaporation capacity</u>	
	<u>Conventional (Six-effect)</u>	<u>Dual-Mode (MVR/Thermal)</u>
Capital cost, 10 ³ \$	684	1,400
	- - - - Annual Costs, 10 ³ \$ - - - -	
Fuel cost		
Cogeneration firing ^a		169
Boiler firing ^b	250	
Purchased electricity cost	54	0
Total energy cost	304	169
Additional maintenance cost (\$.0033/kW-hr)	0	10
Total energy cost reduction ^c		125
Payback ^d /IRR ^{d,e} , yrs/%		10/7

^aNatural gas @ current cogeneration rate of \$0.35/therm, January, 1981.

^bNatural gas @ standard rate of \$0.38/therm, January, 1981.

^cRelative to conventional six-effect system shown on this table.

^dCapital cost factor of 0.0869.

^eInternal Rate of Return before income taxes.

6.5 Pasteurization and Refrigeration Systems

Alternative systems for the pasteurization and refrigeration operations at the Sunkist plant were examined. Those systems were not treated in the same degree of detail as were the systems for central cogeneration, peel drying, and evaporation; however, information sufficient to assess their potential for energy savings and economic return is presented below.

Pasteurization systems. The pasteurization operation is presently carried out with boiler steam that is used to maintain the temperature in a water tank at about 200°F. The citrus juice to be pasteurized flows through plate-type heat exchangers immersed in the steam-heated water bath. A heat pump system that lifts heat from the lower temperature waste-water streams could be used to maintain the water bath temperature. Typically, the pasteurization operation requires about 2.0×10^6 Btu/hr at 200°F. The waste-water stream flow is about 100,000 lb/hr at about 130°F. The system specifications and performance parameters for a heat pump pasteurization system are shown in Table 42. A heat pump system with a coefficient of performance of 3 would require 198 kW of electricity to supply the pasteurization heat requirement of 2.0×10^6 Btu/hr at 200°F. The energy saving and economic characteristics of the Modular Heat Pump Pasteurization system are shown in Table 43. Even though the heat pump system reduces overall energy usage by 21%, it costs \$2.00/hr more to operate. The heat pump system would have to reduce the energy operating cost enough to pay for maintenance, capital use, taxes depreciation, then have a net cost savings large enough to pay pay back the capital in about three years in order to be even considered for implementation. The present cost of fuel energy will have to greatly increase relative to the present cost of electrical energy before the heat pump system would become economically viable.

Table 42. Specifications and performance parameters
for Modular Heat Pump Pasteurization system

Heat delivered to pasteurization, 10^6 Btu/hr	2.0
Pasteurization temperature, $^{\circ}\text{F}$	200
Heat pump coefficient of performance	3.0
Fluid heat source entrance temperature, $^{\circ}\text{F}$	130
Heat source fluid flow rate, lb/hr	100,000
Juice to be pasteurized, lb/hr	15,300
Juice entrance temperature, $^{\circ}\text{F}$	50
Juice specific heat, Btu/lb $^{\circ}\text{F}$	0.9
Number of heat pump units	6
Heat pump coefficient of performance	3.0
Heat delivered per heat pump unit, Btu/hr	333,000
Electrical power consumption per unit, kW	33
Total electrical power consumption, kW	198

Table 43. Energy savings and economic characteristics of Modular Heat Pump Pasteurization system

<u>Energy Parameter</u>	<u>Reference System</u>	<u>Heat Pump System</u>
Pasteurization heat required, 10^6 Btu/hr	2.0	2.0
Steam demand, lb/hr	1,938	None
Fuel energy to supply steam ^a , 10^6 Btu/hr	2.6	None
Electrical demand, kW	None	198
Fuel energy to power production ^b , 10^6 Btu/hr	None	2.0
Total fuel energy input, 10^6 Btu/hr	2.6	2.05
Energy savings, 10^6 Btu/hr		0.55
Percent energy savings		21
<u>Economic Parameter</u>		
User fuel cost @\$3.80/ 10^6 Btu, \$/hr	9.90	None
User electrical cost @\$0.06/kW-hr, \$/hr	None	11.90
Cost savings, \$/hr		-2.00

^aSteam production @75 lb/therm.

^bUtility generated electricity delivered @33% overall efficiency.

Refrigeration system. The Sunkist plant at Ontario, CA presently requires 430 tons of refrigeration at -15°F and 150 tons at 5°F for chilling and storage. This refrigeration is currently produced by electrically-driven, mechanical vapor-compression units. An alternative system, called Modular Dual-mode refrigeration, makes use of an internal combustion heat engine in a cogeneration mode. Both gas turbine (Brayton) and reciprocating engines were considered for systems in which mechanical and absorption refrigeration units were matched to the engine power output and heat rejection characteristics. Modular Dual-mode refrigeration systems are shown in Figures 18 and 19 with Brayton and Reciprocating engines, respectively. In the gas turbine system, a two stage absorption unit is used to produce refrigeration at both 5°F and -15°F from the engine's exhaust heat. In the reciprocating engine system, the heat from the engine's cooling jacket is used to drive a one stage absorption refrigeration unit for 5°F cooling, while the engine's exhaust heat is used to drive a two stage absorption unit to provide cooling at -15°F . In both systems, the mechanical vapor-compression units are driven by the engine's shaft power and produce refrigeration at -15°F . The system specifications and performance parameters of those systems are shown in Table 44, and their energy usage characteristics are shown in Table 45. Both systems provide substantial energy savings of 22% and 33%, respectively, for the Brayton and Reciprocating engine systems. This energy savings is expressed in terms of the total amount of fuel fired, including that required for the utility provided electricity. However, the economic figures of merit for those systems are not particularly attractive as shown in Table 46. The payback period of near 5 years for either system is not viable, especially considering that the initial capital required is over one million dollars. A review of the system design might result in reduced capital cost, and the potential for cost reduction through a systems development effort should be assessed.

Figure 18. Schematic of a modular dual-mode refrigeration unit with a Brayton (gas turbine) engine

Figure 19. Schematic of a modular-dual mode evaporator with a reciprocating engine

Table 44. Specifications and performance parameters
for Modular Dual-mode Refrigeration

	<u>Brayton</u>	<u>Recip.</u>
Total refrigeration capacity, tons		
at -15°F	430	430
at -5°F	150	150
Mechanical refrigeration capacity, tons at -15°F	288	332
Mechanical refrigeration COP	1.3	1.3
Absorption refrigeration capacity, tons at -15°F	142	98
Absorption refrigeration COP at -15°F	0.5	0.5
Absorption refrigeration capacity, tons at 5°F	150	150
Absorption refrigeration COP at 5°F	0.65	0.65
Fuel energy input to engine, 10^6 Btu/hr	11.6	10.0
Engine power to mechanical refrigeration, kW	780	900
Engine exhaust heat recovered, 10^6 Btu/hr	6.2	2.3
Engine cooling heat recovered, 10^6 Btu/hr	NAP	2.8
Exhaust heat input to absorp. at -15°F , 10^6 Btu/hr	3.4	2.3
Exhaust heat input to absorp. at 5°F , 10^6 Btu/hr	2.8	None
Engine cooling heat to absorp. at 5°F , 10^6 Btu/hr	NAP	2.8
Electrical power consumption, kW	47	40

Table 45. Energy savings for Modular Dual-mode Refrigeration

	<u>Reference System</u>	<u>Brayton System</u>	<u>Recip. System</u>
Total refrigeration capacity, tons	580	580	580
Cogeneration fuel consumption	None	11.6	10.0
Electrical power consumption ^a	1,500	47	40
Fuel energy to electricity production ^b , 10 ⁶ Btu/hr	15.5	0.49	0.41
Total fuel energy consumption, 10 ⁶ Btu/hr	15.5	12.1	10.4
Energy savings, 10 ⁶ Btu/hr		3.4	5.1
Percent energy savings		22.	33.

^aPower provided by utility company.

^bUtility generated electricity delivered @ 33% overall efficiency.

Table 46. Capital cost breakdown for
Modular Dual-mode Refrigeration unit

<u>Cost Item</u>	<u>Brayton</u>	<u>Reciprocating</u>
	<u>\$1000</u>	
Energy Conversion Unit		
Gas turbine engine/generator (780 kW)	450	
Reciprocating engine/generator (900 kW)		630
Heat recovery unit	25	30
Absorption refrigeration unit	440	375
Installation (foundation, piping, & ancillary components)	150	200
Monitoring and control system	<u>50</u>	<u>60</u>
Subtotal	1115	1295
Engineering and Supervision (10%)	<u>110</u>	<u>130</u>
Total cost of installed system	1225	1425

Table 47. Economic characteristics of Modular Dual-mode Refrigeration

<u>Total refrigeration capacity of 680 tons</u>			
	<u>Reference System</u>	<u>Brayton System</u>	<u>Recip. System</u>
Engine power output, kW	none	780	900
Additional capital, 10 ⁶ \$	none	1.23	1.43
- - - - Annual costs ^a , \$1000 - - - -			
Fuel cost ^b	none	353	305
Electricity cost ^c	786	24	18
Total energy cost		377	323
Energy cost reduction ^d		409	463
Additional maintenance		47	55
Payback ^e /IRR ^{e,f} , yrs/%		4.8/20	5.0/21

^aBased on 8700 hrs operation per year.

^bNatural gas @ current cogeneration rate of \$0.35/therm.

^cElectricity @ \$0.06 kW-hr.

^dRelative to present system shown in this table.

^eCapital cost factor of 0.0869.

^fInternal Rate of Return before income taxes.

7. FINDINGS AND RECOMMENDATIONS

The findings and recommendations for the alternative systems that were analyzed and evaluated in this study are given below according to system type and plant operation.

CENTRAL SYSTEMS

Central cogeneration systems for electricity and steam. The performance and economic characteristics of central cogeneration systems were discussed in Section 6.2 of this report. The Brayton and Rankine cogeneration systems were found to have economic benefits that merit a serious consideration of their implementation in citrus processing plants. Under the economic scenarios of this study, the Brayton and Rankine cogeneration systems payback their invested capital in less than three years, based on net savings. In addition to its economic benefit, the Brayton cogeneration system gives a 29% reduction in overall energy use according to the methods used in this study. In the face of uncertain future energy prices and changing plant energy demand, the Brayton system may offer the economic benefits of cogeneration at lower risk than the Rankine system. As conservation measures are introduced in the plant, the steam consumption is likely to be reduced more rapidly than electricity consumption, which casts the Rankine system less favorably due to its very high ratio of steam to electricity production. Therefore, the Brayton system is preferred due to its energy economy and adaptability to future plant energy demand.

MODULAR SYSTEMS

Peel drying operation. Alternative methods of supplying heat to the peel drying system were analyzed and evaluated in Section 6.3 of this report. A total of four different system configurations based on Brayton and Reciprocating engine cogeneration schemes were considered. Two systems - the parallel arrangement for both the Brayton and Reciprocating engine were found to be technically viable

at the present time, but offered no energy savings and no economic incentive. A third system - the simple series arrangement for a Brayton engine with the peel dryer drum - was found to offer modest energy savings of near 12% but is decidedly unattractive both operationally and economically as discussed in Section 6.3. The fourth alternative system for the peel drying operation consists of a Brayton engine coupled to a low-excess-air afterburner that provides for operational flexibility and does not interfere with the performance of the waste heat evaporator. This system provides a moderate energy savings of 12%, and it has the potential to become economically viable. However, this is a new system concept that has never been tried in actual operation at any scale, and the low-excess-air afterburner is not a commercially available component. Therefore, some degree of system development is required before the Brayton engine/Afterburner peel dryer system is commercially viable. This development activity is recommended.

Evaporation operation. Two alternative evaporator systems were analyzed and evaluated in Section 6.3 of this report. The first is a presently available steam turbine system that offers modest energy savings and economic benefit. This system should be seriously considered for implementation, but is not of high priority because it provides only a small annual cash saving. The second system - the Modular Dual-Mode Evaporator - is a new concept that requires a substantial systems development effort. The modular dual-mode evaporator consists of a gas turbine engine which drives a mechanical vapor recompression evaporator unit and whose exhaust heat is used in a thermal evaporator unit. This system offers a 40% reduction in energy usage and has the potential for economic viability. A systems development project for the Modular-Dual-Mode Evaporator is recommended.

Pasteurization operation. A heat pump system that lifts heat from waste-water streams at about 130°F to provide heat for pasteurization process was analyzed and evaluated. The heat pump system offers no economic benefit, in fact, it would increase the

cost of the pasteurization operation. The cost of fuel relative to electricity would likely have to more than double before this system would become economically viable.

Refrigeration Operation. An alternative system concept for the refrigeration operation was analyzed and evaluated in Section 6.5 of this report. This system consisted of either a Brayton or a Reciprocating engine whose shaft power drives a mechanical vapor-compression refrigeration unit and whose waste heat drives an absorption refrigeration unit. These systems were matched to meet a certain portion of the typical refrigeration load at a Sunkist plant. The modular dual-mode refrigeration systems are based completely on commercially available components. Some sophisticated engineering may be required for systems integration, but such systems could likely be put to operation with little, if any, developmental effort. The modular dual-mode refrigeration systems provide 20% to 30% energy savings but have marginal economic benefit at the present time. Some capital cost reduction may result from a review and revision of the systems design of Section 6.5. Such an effort is recommended.

(1) SCAQMD Rule 476 - Steam Generating Equipment

(a) A person shall not discharge into the atmosphere from any equipment having a maximum heat input rate of more than 12.5 million kilogram calories (50 million BTU) per hour used to produce steam, for which a permit to build, erect, install or expand is required after May 7, 1976, air contaminants that exceed the following:

(1) Oxides of nitrogen, expressed as nitrogen dioxide (NO_2), calculated at 3 percent oxygen on a dry basis averaged over a minimum of 15 minutes, as shown in the following table:

FUEL	GAS	LIQUID OR SOLID
Concentration	125 ppm NO_2	225 ppm NO_2

when more than one type of fuel is used, the allowable concentration shall be determined by proportioning the gross heat input and allowable concentration of each fuel.

(2) Combustion contaminants that exceed both of the following two limits:

(A) 5 kilograms (11 pounds) per hour.

(B) 23 milligrams per cubic meter (0.01 gr/SCF)

calculated at 3 percent oxygen on a dry basis

averaged over a minimum of 15 consecutive minutes.

(b) Nothing in this rule shall be construed as preventing the maintenance or preventing the alteration or modification of existing steam generating equipment which will not increase the mass of air contaminant emissions.

(2) SCAQMD Rule 407 - Liquid and Gaseous Air Contaminants

Carbon monoxide shall not exceed 2000 ppm measured on a dry basis, averaged over a minimum of 15 consecutive minutes.

- (3) No specific rule has been promulgated concerning hydrocarbons from boilers or gas turbines in this size range.

(4) SCAQMD Rule 404 (c) - Particulate Matter-Concentration

Steam generators and gas turbines are exempted.

SCAQMD Rule 405 - Solid Particulate Matter, Weight

- (a) A person shall not discharge into the atmosphere from any source, solid particulate matter including lead and lead compounds, in excess of the rate shown in Table 405 (A).

Where the process weight per hour is between figures listed in the table, the exact weight of permitted discharge shall be determined by linear interpolation.

- (b) A person shall not discharge into the atmosphere in any one hour from any source, solid particulate matter including lead and lead compounds, in excess of 0.23 kilogram (0.5 pound) per 907 kilograms (2000 pounds) of process weight.

For the purpose of this subsection only, process air shall be considered to be a material, introduced into the process when calculating process weight.

- (c) For the purpose of this rule, emissions shall be averaged over one complete cycle of operation or one hour, whichever is the lesser time period.

(5) SCAQMD Rule 409 - Combustion Contaminants

Combustion contaminants measured as grams per cubic meter of gas calculated to 12 percent of carbon dioxide (CO₂) at standard conditions averaged over a minimum of 15 consecutive minutes shall not exceed a value of 0.23.

(6) SCAQMD Rule 475 - Electric Power Generating Equipment

(u) Alternative Energy Projects

(1) Exemptions: The provisions of this Rule, exclusive of Subsection (u) (2) of this Part, are not applicable to a cogeneration unit(s) or a unit(s) in which refuse-derived fuel or biomass-derived fuel is burned to satisfy at least 50 percent of the total heat demand of that unit(s). For the purposes of this Rule, cogeneration unit(s) means any electric power generating unit(s) which concurrently recovers for sale by the electric power generating system owner or operator a substantial fraction, to be determined by the Executive Officer but in no event less than 25 percent, of the input energy as other forms of energy for utilization for industrial or commercial heating or cooling purposes. For the purpose of this Rule, cogeneration units do not include combined cycle generating units.

(2) Modified Units: All existing units which are not exempted from the provisions of this Rule pursuant to Subsection (u) (1) of this Part, shall, for the purpose of this Rule, be considered new units and shall be subject to the provisions of Rule 213. (Standards for Permits to Construct: Air Quality Impact).

(7) Best Available Control Technology (BACT) means the more stringent of:

- (1) The most effective emission control technique which has been achieved in practice, for such permit unit category or class of source, or
 - (2) The control technique which will result in the most stringent emissions limitation contained in any state implementation plan approved by the Environmental Protection Agency for such permit unit category or class or source unless the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer that such control techniques are not available (i.e., that such emissions limitations are not presently achievable). No control technique, the application of which would result in emissions from a new or modified source in excess of the amount allowable under applicable new source performance standards specified in Regulation IX of these Rule and Regulations may be considered Best Available Control Technology, or
 - (3) Any other emissions control technique found, after public hearing, by SCAQMD or the Air Resources Board to be technologically feasible and cost/effective for such class or category of sources or for a specific source.
- (8) BACT required. BACT for gas turbines is water or steam injection.
- (9) New Source Performance Standards (NSPS). NSPS have not been promulgated for this size of equipment.
- (10) Sulfur content of natural gas must be 80 ppm or less (calculated as hydrogen sulfide) (SCAQMD Rule 431.1).

- (11) New Source Review Rule (NSR). SCAQMD Regulation XIII concerns procedures to be followed and limitations to be met by new source of air contaminants.

SCAQMD Rule 1303 - Applicability and Analysis

(a) Applicability

The provisions of this regulation shall apply to new stationary sources or modifications to existing stationary sources and relocation to non-contiguous property of existing stationary sources as provided in subsection (c) which result in a net emission increase from such stationary source of any air contaminant greater than 68 kilograms (150 pounds) per day except carbon monoxide for which the value is an increase of 340 kilograms (750 pounds) per day.

(b) Analysis

The Executive Officer shall deny the permits to construct for permit units subject to this regulation as provided by Rule 1303 (a) unless:

- (1) The new source or modification complies with all applicable rules and regulations of the District; and
- (2) The applicant certifies in writing prior to the issuance of such permit that all stationary sources owned or operated by such person (or by any entity controlling, controlled by, or under common control with such person) in the State of California are in compliance with all applicable emission limitations and standards under the Clean Air Act (42 USC 7401 et, seq) and all applicable emission limitations and standards which are part of the state implementation plan approved by the Environmental Protection Agency

or on a compliance schedule approved by the appropriate federal, state or district officials. The requirements of this subsection shall apply to stationary sources with allowable emissions of any air contaminant of 25 tons per year or more; and

- (3) The new source or modification will be constructed using BACT for each affected air contaminant. In carrying out this provision, the Executive Officer shall annually publish a guideline of BACT for commonly processed permit unit categories or classes of sources. BACT for other permit unit categories or classes of sources shall be determined on a case-by-case basis; and
- (4) The net increase in emissions for each affected air contaminant has been offset pursuant to Rule 1307; and
- (5) The applicant has substantiated with modeling or other analyses approved by the Executive Officer that the new source or modification will not cause a violation or make measurably worse an existing violation of any national ambient air quality standard at the point of maximum ground level impact. However, modeling shall not be required if all offset sources are within a distance of 8 kilometers (5 miles) from the affected permit units; and
- (6) The Executive Officer determines that the new source or modification will not result in emissions which interfere with the schedule of reasonable further progress set forth in the state implementation plan for the South Coast Air Quality Management District, approved by the Environmental Protection Agency.

(b) The provisions of this regulation shall apply to existing stationary sources relocated to non-contiguous properties, provided:

- (1) The relocation distance is greater than 8 kilometers (5 miles) and the emissions of any air contaminant, at the new location, are greater than 68 kilograms (150 pounds) per day except carbon monoxide for which the value is 340 kilograms (750 pounds) per day; or
- (2) The relocation distance is less than 8 kilometers (five miles) and there is a net emission increase of any air contaminant greater than 68 kilograms (150 pounds) per day except carbon monoxide for which the value is an increase of 340 kilograms (750 pounds) per day.

SCAQMD Rule 1304 -Exemptions from Regulation XIII

Upon approval by the Executive Officer, and provided BACT is employed on the subject permit units, an exemption from this regulation, for one or more air contaminants as appropriate, shall be allowed for the permit unit or source which:

(e) Resource Conservation and Energy Projects

Is a cogeneration project, a project using refuse-derived or biomass-derived fuels for useful energy generation, a resource recovery project using municipal wastes, or other energy related project but excluding such other energy-related projects at power plants or refineries, provided:

- (1) the applicant establishes by modeling that the affected source will not cause a new violation or make measurably worse an existing violation of any national ambient air quality standard at the point of maximum ground level impact; and
- (2) the applicant demonstrates that best efforts have been made to obtain the required emission offsets, and that the applicant certifies that required offsets will be sought until construction of the affected source begins, and that all required offsets available shall be used; and
- (3) the Executive Officer determines that the project will not interfere with the schedule of reasonable further progress set forth in the state implementation plan for the South Coast Air Quality Management District, approved by the Environmental Protection Agency;

(12) SCAQMD Rule 1302

(g) Cogeneration Project means a project which

- (1) makes use of exhaust steam, waste steam, waste steam heat, or resultant energy from an industrial, commercial, or manufacturing plant or process for the generation of electricity, or
- (2) makes use of exhaust steam, waste steam, or heat from a thermal power plant, in an industrial, commercial, or manufacturing plant or process.

For the purposes of this definition the "industrial, commercial or manufacturing plant or process" shall not be a thermal power plant or portion thereof. A cogeneration project shall not consist of steam or heat developed solely for electrical power generation. To qualify

as a cogeneration project, the processes listed in (1) and (2) above must concurrently recover for useful purposes, at the first stage of heat transfer, not less than 25 percent of the energy.

(13) Limits (Net Increase of any specific pollutant, e.g., NOX)

1. Less than 15 lbs/hr, 150 lbs/day
 - A. No specific rules
 - B. BACT may be required for permit
2. 15 to 25 lbs/hr, 150 to 250 lbs/day
 - A. BACT required
 - B. Exemption per SCAQMD Rule 1304 (see note 11)
3. 25 lbs/hr, 150 to 250 lbs/day
 - A. BACT required
 - B. Emission offsets from offsite source
 - C. Air modeling which shows no worsening of any national ambient air quality standard.

APPENDIX II - Cost Estimate for Central Brayton cogeneration system

This cost estimate was prepared entirely independently of that given in Table 13 of Section 6.2. The total installed cost here is \$1.54 million and the corresponding cost in Table 13 is \$1.59 million.

Equipment:

Gas Compressor ¹ (\$230,000), Switchgear ² (\$150,000)	380,000
Allison 501K Turbine Generator	750,000
Conseco Waste Heat Boiler w/Silencer	260,000
Shipping (Mintz Equipment Co, El Monte, CA)	
Generator: Indianapolis IN to Ontario, CA	4,250
Boiler: Medford, WI to Ontario, CA	4,875

Subtotal \$1,299,125

Installation:

Foundation

Permits, Plan check, etc. (City of Ontario)	1,560
Surveying, Data reduction and drafting	2,112
Technical Services, (soil tests, compression testing, etc.)	600
Grading, backfill, compaction, backfill, etc.	2,862
Slab, 12" structural, w/250# rebar per	11,206
Add for air-entrained concrete	75
Stand-by costs (Mixer trucks)	270
Miscellaneous (bolts, inserts, etc.)	500

Contingency (Subcontractor's overhead, profit, etc.)

2,878
Subtotal \$ 22,063

Equipment Emplacement:

Truck Crane, 35 ton, 125 foot, w/operators	12,250
(clearance 11' 9") mobilization and removal	10,300
Place engine-generator (leadman, rigger, 2 fitters)	5,760
Place boiler	5,760

Subtotal \$ 33,770

¹Included in installation cost of Table 13 - Capital Cost Breakdown for Brayton System.

²Separately listed as Generator substation & connections in Table 13.

Fuel Line:

Pipe, flanges, fittings, valves, etc.	2,300
Hose Bridges (\$564.38x4)	2,258
Installation	2,880
Subtotal \$	<u>7,438</u>

Water Line: (Similar to Fuel Line)

	<u>7,500</u>
Subtotal \$	7,500

Steam Line: (Triangle Pipe & Supply Co., L.A.)

Material:

6"-300# standard flange (8 @ \$69.08)	534
2"-300# standard flange-input (6 @ \$19.35)	154
2"-300# standard flange-output (6 @ \$19.35)	154
6" dia pipe @ \$18.66/foot-100 ft	1,866
2" dia pipe @ \$3.00/foot-200 ft	600
Fittings, elbows, clamps, hangers, etc.	750
Subtotal \$	<u>4,060</u>

Installation:

Cut, thread, assemble, install 2" input line	1,920
Cut, thread, assemble, install 2" output line	1,920
Cut, thread, assemble, install 6" super-heater line	
	<u>5,760</u>
Subtotal \$	<u>9,600</u>

Exhaust Stack:

Material (Triangle Pipe & Supply Co.-L.A.)

42" dia duct-10 foot lengths-	
(80 ft @ \$21.99/ft)	1,759
42" dia. 50 lb std. flange-	
(16 @ 57.31 ea)	916
Hardware (guy wire, bolts, washers, screweyes, etc.)	600

Installation:

Scaffolding: rental, erect & dismantle	1,200
Erect stack, assemble, weld, anchor, etc.	<u>10,440</u>

Subtotal \$ 14,916

Electrical:

Panels, controls, etc.	4,200
Power line to substation-material	11,500
Power line to substation-installation	<u>5,500</u>
Subtotal \$	21,200

Engineering:

75 drawings @ 24 hrs/@ \$50.00/hr	90,000
Subtotal	\$ 90,000
TOTAL	\$1,509,672
Contingency	\$ 32,000
Grand Total	\$1,541,672

APPENDIX III - Example Economic Calculation for Constant Costs

A sample calculation of the Payback period and the Internal Rate of Return for the Brayton Central cogeneration system for constant energy prices is given below. This sample calculation is based on the following parameters:

Electricity price	\$0.06/kWhr
Cogeneration natural gas price	\$0.35/therm
Regular natural gas price	\$0.38/therm
Cogeneration heat rate	12000 Btu/kWhr
Plant hours of operation	6024 hrs/yr
Cogeneration steam production	5.59 lb/kWhr
Plant steam load	580x10 ⁶ lb/yr
Plant electrical load	51x10 ⁶ kWhr/yr
Cogeneration plant capacity	3060 kW

The fuel cost consists of cogeneration firing cost and supplementary, if any, firing cost. Cogeneration fuel cost is calculated from

$$\text{Cogen. fuel cost} = \frac{\text{Btu}}{\text{kWhr}} \times \frac{\text{hrs of operation}}{\text{yr}} \times \text{fuel price} \times \text{kW capacity}$$

substituting values gives

$$\begin{aligned} \text{Cogen. fuel cost} &= 12000 \frac{\text{Btu}}{\text{kWhr}} \times 6024 \frac{\text{hrs}}{\text{yr}} \times \$0.35/\text{therm} \times 3060 \text{ kW} \times 10^{-5} \frac{\text{therm}}{\text{Btu}} \\ &= \$0.774 \times 10^6 \end{aligned}$$

Additional steam required = Plant steam load - Cogen. steam produced

$$\begin{aligned} \text{Cogen. steam produced} &= \frac{\text{lb}}{\text{kWhr}} \times \frac{\text{hrs}}{\text{yr}} \times \text{kW} \\ &= 5.59 \times 6024 \times 3060 \\ &= 103 \times 10^6 \text{ lb/yr} \end{aligned}$$

$$\begin{aligned} \text{Additional steam required} &= (580 \times 10^6 - 103 \times 10^6) \text{ lb/yr} \\ &= 477 \times 10^6 \text{ lb/yr} \end{aligned}$$

$$\begin{aligned} \text{Supplementary firing cost} &= 477 \times 10^6 \text{ lb/yr} \times \$0.38/\text{therm} \times \frac{\text{therm}}{75 \text{ lb}} \\ &= \$2.42 \times 10^6 \end{aligned}$$

Purchased electricity cost = Plant elec. load - Cogen. elec. production

$$\begin{aligned} &= 51 \times 10^6 \frac{\text{kWhr}}{\text{yr}} \times \$0.06/\text{kWhr} - (3060 \text{ kW} \times 6024 \frac{\text{hrs}}{\text{yr}} \times \$0.06/\text{kWhr}) \\ &= \$1.95 \times 10^6/\text{yr} \end{aligned}$$

Total energy cost = Cogen. fuel cost + Suppl. firing cost + Purchased elec. cost

$$\begin{aligned} &= \$(0.744 + 2.42 + 1.95) \times 10^6 \\ &= \$5.14 \times 10^6 \end{aligned}$$

$$\text{Present energy cost} = \$6.00 \times 10^6$$

Total energy cost reduction = Present energy cost - Cogen energy cost

$$\begin{aligned} &= \$(6.00 - 5.14) \times 10^6 \\ &= \$0.86 \times 10^6/\text{yr} \end{aligned}$$

Maintenance cost = kW capacity $\times \frac{\text{hrs operation}}{\text{yr}}$ $\times$ maint. rate, \$/kWhr

$$\begin{aligned} &= 3060 \times 6024 \times 0.0022 \\ &= \$0.04 \times 10^6 \end{aligned}$$

The Payback period is calculated as follows:

$$\text{Payback (yrs)} = \frac{\text{Additional Capital}}{\text{Net benefit rate}}$$

and

$$\text{Net benefit rate} =$$

$$\text{Energy cost reduction} - \text{Maintenance Cost} - (f \times \text{Add. capital})$$

where f is the capital cost factor (see Appendix VI)

then

$$\begin{aligned} \text{Payback (yrs)} &= \frac{1.75}{0.86 - 0.04 - (0.0869 \times 1.75)} \\ &= \frac{1.75}{0.668} = 2.6 \text{ years} \end{aligned}$$

The internal rate of return is calculated by requiring that

$$\text{Present worth of cost} = \text{Present worth of benefit}$$

and in this case

$$\text{Present worth of cost} = \$1.75 \times 10^6$$

The internal rate of return i may be found from compound interest tables as that interest rate which results in the net annual benefit over the life of the system being discounted to the present worth of the cost. In this case, for a system life of 20 years, $i = 38\%$.

APPENDIX IV - Economic Calculations for Escalating Costs

The calculation methods for Payback and Internal Rate of Return under escalating fuel, electricity and maintenance costs are given in the following.

Payback period

With escalating fuel, electricity and maintenance costs the payback calculation proceeds as follows:

The net energy cost savings/reduction is determined as in Appendix III except that escalated prices for each successive year are used. This results in a different value of the annual net energy savings for each year.

The payback period is determined by summing the net cost savings for successive years until the accumulated energy cost savings is sufficient to offset the initial investment. For example, the first year net cost savings for the Central Brayton system under Scenario A is \$795,000, and the second year net cost savings is \$970,000. Hence, the total energy cost savings during the two year period is \$1,760,000, which is sufficient to pay off the investment; therefore the payback period is two years.

Internal Rate of Return

The costs of fuel, electricity, and maintenance were escalated, then used in determining net annual energy cost savings by the procedure shown in Appendix III. The net annual cost saving was different for each year due to the changing prices. The Internal Rate of Return, i , was found according to the relation

$$C_0 = \frac{A_1}{(1+i)} + \frac{A_2}{(1+i)^2} + \frac{A_3}{(1+i)^3} + \cdots + \frac{A_{20}}{(1+i)^{20}}$$

where $A_1, A_2, A_3, \dots, A_{20}$ are the net savings in years one through twenty, as defined by

Annual Net Savings = Energy savings - Maintenance cost - (f x Additional capital)

where f is the capital cost factor* and C_0 is the initial capital investment.

For Central Brayton cogeneration, using Scenario A cost projections, the internal rate of return, i, is defined by the equation

$$\begin{aligned}
 1.75 = & \frac{0.795}{(1+i)} + \frac{0.97}{(1+i)^2} + \frac{1.166}{(1+i)^3} + \frac{1.391}{(1+i)^4} + \frac{1.645}{(1+i)^5} + \frac{2.02}{(1+i)^6} \\
 & + \frac{2.474}{(1+i)^7} + \frac{2.997}{(1+i)^8} + \frac{3.639}{(1+i)^9} + \frac{4.422}{(1+i)^{10}} + \frac{5.343}{(1+i)^{11}} + \frac{6.444}{(1+i)^{12}} \\
 & + \frac{7.774}{(1+i)^{13}} + \frac{9.352}{(1+i)^{14}} + \frac{11.30}{(1+i)^{15}} + \frac{13.49}{(1+i)^{16}} + \frac{16.26}{(1+i)^{17}} + \frac{19.56}{(1+i)^{18}} \\
 & + \frac{23.54}{(1+i)^{19}} + \frac{28.12}{(1+i)^{20}}
 \end{aligned}$$

The value of the internal rate of return before taxes which satisfies the above equation is found to be 94%.

*See Appendix VI - for derivation of capital cost factor.

APPENDIX V

Central Cogeneration System Simulation Results for Gas Turbine Engine - Waste Heat Boiler 3060 KW

Seven consecutive days of operation representing plant duty
cycle during typical summer season.

15 MIN ELEC DEMAND FROM INPUT

5340.000	5280.000	5172.000	5148.000	5052.000	5088.000	5208.000	5100.000
4896.000	4836.000	4800.000	4764.000	4272.000	4056.000	3912.000	3708.000
3768.000	4260.000	3660.000	3312.000	3060.000	3120.000	3000.000	3048.000
3120.000	2784.000	2808.000	2664.000	2580.000	2628.000	2688.000	2664.000
2688.000	2592.000	2568.000	2604.000	2628.000	2592.000	2448.000	2376.000
2472.000	2472.000	2460.000	2472.000	2496.000	2484.000	2496.000	2472.000
2472.000	2412.000	2424.000	2340.000	2400.000	2472.000	2532.000	2508.000
2424.000	2316.000	2412.000	2424.000	2244.000	2124.000	2268.000	2316.000
2160.000	2184.000	2352.000	2256.000	2112.000	2160.000	2352.000	2304.000
2196.000	2268.000	2400.000	2304.000	2172.000	2220.000	2412.000	2304.000
2196.000	2316.000	2352.000	2196.000	2160.000	2316.000	2232.000	2148.000
2196.000	2544.000	2544.000	2460.000	2472.000	2700.000	2748.000	2676.000

CALC HOURLY ELEC DEMAND FROM ABOVE INPUT

5235.000	5112.000	4824.000	3987.000	3750.000	3057.000	2444.000	2640.000
2613.000	2511.000	2469.000	2487.000	2412.000	2478.000	2394.000	2238.000
2238.000	2232.000	2292.000	2277.000	2265.000	2214.000	2436.000	2649.000

STEAM DEMAND IN 1000 CU FT OF NAT GAS FROM INPUT

87.000	86.000	83.000	77.000	73.000	50.000	45.000	25.000
7.000	6.000	5.000	5.000	5.000	4.000	5.000	15.000
12.000	14.000	13.000	14.000	14.000	14.000	10.000	10.000

HOURLY COGEN PLANT DATA

HOOR	STEAM DEMAND (LB/HR)	ELECTRICITY DEMAND (KW)	STEAM FROM COGEN (LB/HR)	ELECTRICITY FROM COGEN (KW)	STEAM FROM BOILER (LB/HR)	ELECTRICITY BOUGHT (KW)	ELECTRICITY SOLD (KW)	BOILER FUEL COST (\$)	COGEN FUEL COST (\$)
1	65250.00	5235.00	17100.00	3060.12	48150.00	2174.88	.00	243.96	134.41
2	64500.00	5112.00	17100.00	3060.12	47400.00	2051.88	.00	240.16	134.41
3	62250.00	4824.00	17100.00	3060.12	45150.00	1763.88	.00	228.76	134.41
4	57750.00	3987.00	17100.00	3060.12	40650.00	926.88	.00	205.96	134.41
5	54750.00	3750.00	17100.00	3060.12	37650.00	689.88	.00	190.76	134.41
6	37500.00	3057.00	17100.00	3060.12	20400.00	.00	3.12	103.36	134.41
7	33750.00	2844.00	17100.00	3060.12	16650.00	.00	216.12	84.36	134.41
8	18750.00	2640.00	17100.00	3060.12	1650.00	.00	420.12	8.36	134.41
9	6750.00	2613.00	.00	.00	6750.00	2613.00	.00	34.20	.00
10	4500.00	2511.00	.00	.00	4500.00	2511.00	.00	22.80	.00
11	3750.00	2469.00	.00	.00	3750.00	2469.00	.00	19.00	.00
12	3750.00	2487.00	.00	.00	3750.00	2487.00	.00	19.00	.00
13	3750.00	2412.00	.00	.00	3750.00	2412.00	.00	19.00	.00
14	3000.00	2478.00	.00	.00	3000.00	2478.00	.00	15.20	.00
15	3750.00	2394.00	.00	.00	3750.00	2394.00	.00	19.00	.00
16	11250.00	2238.00	11250.00	1588.38	.00	649.62	.00	.00	89.69
17	9000.00	2238.00	.00	.00	9000.00	2238.00	.00	45.60	.00
18	10500.00	2232.00	.00	.00	10500.00	2232.00	.00	53.20	.00
19	9750.00	2292.00	.00	.00	9750.00	2292.00	.00	49.40	.00
20	10500.00	2277.00	.00	.00	10500.00	2277.00	.00	53.20	.00
21	10500.00	2265.00	.00	.00	10500.00	2265.00	.00	53.20	.00
22	10500.00	2214.00	.00	.00	10500.00	2214.00	.00	53.20	.00
23	7500.00	2436.00	.00	.00	7500.00	2436.00	.00	38.00	.00
24	7500.00	2649.00	.00	.00	7500.00	2649.00	.00	38.00	.00
SUM	510750.00	69654.00	148050.00	26069.31	362700.00	44224.04	639.35	1837.68	1164.98

NAMelist VARIABLES INPUT TO SUBROUTINE BYSL

```

SINBYSL
IRN      =          +1
ISN      =          +1
PMON     =      .75720000E+04
PMID     =      .73440000E+04
IUFF     =          +9
MID1     =          +13
MID2     =          +23
IUN      =          +19
A1       =      .12660000E-01
A2       =      .50500000E+01
A3       =      .41300000E-01
A4       =      .21000000E-02
B1       =      .92900000E-02
B2       =      .65000000E+00
C1       =      .59300000E-02
KCC      =      .18670000E+02
KTAX     =      .19000000E-03
KUN      =      .11000000E+00
KMIU     =      .80000000E-01
KOFF     =      .50000000E-01
V        =      .30000000E-01
ICHECK   =          +1
$END

```

HOURLY ELECTRICITY BOUGHT

2174.88	2051.88	1763.88	926.88	689.88	.00	.00	.00
2613.00	2511.00	2469.00	2487.00	2412.00	2478.00	2394.00	649.62
2238.00	2232.00	2292.00	2277.00	2265.00	2214.00	2436.00	2649.00

HOURLY ELECTRICITY SOLD

.00	.00	.00	.00	.00	3.12	216.12	420.12
.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00

```

$CHECK
$UN      =      .00000000E+00
$UN      =      .12293622E+05
$MIU     =      .00000000E+00
$MIU     =      .19071000E+05
$UFF     =      .63935029E+03
$UFF     =      .12869416E+05
$UN      =      .19104415E+04
$MIU     =      .11138332E+04
$UFF     =      .60553305E+03
$CB      =      .36563202E+04
$CB      =      .31967514E+02
$END

```

DAILY COGEN PLANT DATA

PLANT STEAM DEMAND = 510750.00 LBS
 PLANT ELECTRIC DEMAND = 69654.00 KW-HR
 BOILER STEAM = 362700.00 LBS
 COGEN STEAM = 148050.00 LBS
 COGEN ELECTRICITY = 26069.31 KW-HR
 UTILITY ELECTRICITY = 44224.04 KW-HR
 BOILER FUEL COST = \$ 1837.68
 COGEN FUEL COST = \$ 1164.98
 PLANT ELECTRICITY COST = \$ 3656.32
 COGEN ELECTRICITY WORTH = \$ 31.97
 PLANT TOTAL ENERGY COST = \$ 6627.01
 COGEN UNIT IS OFF FOR 15 HOURS

15 MIN ELEC DEMAND FROM INPUT

2592.000	2628.000	2472.000	2520.000	2628.000	2592.000	2508.000	2556.000
2664.000	2652.000	2676.000	2736.000	2832.000	2688.000	2676.000	2700.000
2868.000	2808.000	2700.000	2688.000	2724.000	2820.000	2676.000	2940.000
3492.000	3708.000	3972.000	4260.000	4548.000	4944.000	5088.000	5270.000
5196.000	5280.000	5328.000	5184.000	5244.000	5508.000	5892.000	6072.000
6072.000	6108.000	6192.000	5952.000	5592.000	5616.000	6312.000	6396.000
6084.000	6336.000	6384.000	6336.000	6180.000	6216.000	6324.000	6396.000
6708.000	6828.000	6732.000	6624.000	6576.000	6276.000	6216.000	6120.000
6240.000	6180.000	6204.000	6204.000	6492.000	6408.000	6492.000	6528.000
6540.000	6396.000	6576.000	6276.000	6012.000	5796.000	6000.000	5964.000
6204.000	6096.000	5988.000	6072.000	5844.000	5892.000	6072.000	6204.000
6516.000	6504.000	6312.000	6240.000	6360.000	6324.000	6168.000	6252.000

CALC HOURLY ELEC DEMAND FROM ABOVE INPUT

2593.000	2571.000	2682.000	2724.000	2766.000	2790.000	3858.000	4950.000
5247.000	5679.000	6081.000	5979.000	6285.000	6279.000	6723.000	6297.000
6207.000	6480.000	6447.000	5943.000	6090.000	6003.000	6393.000	6276.000

STEAM DEMAND IN 1000 CU FT OF NAT GAS FROM INPUT

.000	10.000	11.000	13.000	11.000	15.000	13.000	14.000
14.000	35.000	31.000	31.000	29.000	31.000	32.000	37.000
38.000	40.000	37.000	45.000	50.000	49.000	50.000	46.000

HOURLY COGEN PLANT DATA

HOOR	STEAM DEMAND (LB/HR)	ELECTRICITY DEMAND (KW)	STEAM FROM COGEN (LB/HR)	ELECTRICITY FROM COGEN (KW)	STEAM FROM BOILER (LB/HR)	ELECTRICITY BOUGHT (KW)	ELECTRICITY SOLD (KW)	BOILER FUEL COST (\$)	COGEN FUEL COST (\$)
1	.00	2553.00	.00	.00	.00	2553.00	.00	.00	.00
2	7500.00	2571.00	.00	.00	7500.00	2571.00	.00	38.00	.00
3	8250.00	2682.00	.00	.00	8250.00	2682.00	.00	41.80	.00
4	9750.00	2724.00	.00	.00	9750.00	2724.00	.00	49.40	.00
5	8250.00	2766.00	.00	.00	8250.00	2766.00	.00	41.80	.00
6	11250.00	2790.00	11250.00	1588.38	.00	1201.62	.00	103.36	89.58
7	9750.00	3858.00	.00	.00	9750.00	3858.00	.00	49.40	.00
8	10500.00	4950.00	.00	.00	10500.00	4950.00	.00	53.20	.00
9	10500.00	5247.00	.00	.00	10500.00	5247.00	.00	53.20	.00
10	26250.00	5679.00	17100.00	3060.12	9150.00	2618.88	.00	46.36	134.41
11	23250.00	4081.00	17100.00	3060.12	6150.00	3020.88	.00	31.16	134.41
12	23250.00	5979.00	17100.00	3060.12	6150.00	2918.88	.00	31.16	134.41
13	21750.00	6285.00	17100.00	3060.12	4650.00	3224.88	.00	23.56	134.41
14	23250.00	6279.00	17100.00	3060.12	6150.00	3218.88	.00	31.16	134.41
15	24000.00	6723.00	17100.00	3060.12	6900.00	3462.88	.00	34.96	134.41
16	27750.00	6297.00	17100.00	3060.12	10650.00	3236.88	.00	53.96	134.41
17	28500.00	6207.00	17100.00	3060.12	11400.00	3146.88	.00	57.76	134.41
18	30000.00	6480.00	17100.00	3060.12	12900.00	3419.88	.00	65.36	134.41
19	27750.00	6447.00	17100.00	3060.12	10650.00	3386.88	.00	53.96	134.41
20	33750.00	5943.00	17100.00	3060.12	16650.00	2882.88	.00	44.36	134.41
21	37500.00	6090.00	17100.00	3060.12	20400.00	3029.88	.00	103.36	134.41
22	36750.00	6003.00	17100.00	3060.12	19650.00	2942.88	.00	99.56	134.41
23	37500.00	6393.00	17100.00	3060.12	20400.00	3332.88	.00	103.36	134.41
24	34500.00	6276.00	17100.00	3060.12	17400.00	3215.88	.00	88.16	134.41
SUM	511500.00	123303.00	267750.00	47490.13	243750.00	75812.86	.00	1235.00	2105.87

NAMelist VARIABLES INPUT TO SUBROUTINE BYSL

```

$INBYSL
IRN      =          +1
ISN      =          +1
PRON     =      .75720000E+04
PRID     =      .73440000E+04
IOFF     =          +0
RID1     =          +13
RID2     =          +23
ION      =          +19
A1       =      .12660000E-01
A2       =      .50500000E+01
A3       =      .41300000E-01
A4       =      .21000000E-02
B1       =      .92900000E-02
B2       =      .65000000E+00
C1       =      .59300000E-02
KCC      =      .18670000E+02
NTAX     =      .19000000E-03
NUM      =      .11000000E+00
MMID     =      .80000000E-01
KOFF     =      .50000000E-01
V        =      .30000000E-01
ICHECK   =          +1
$END
    
```

HOURLY ELECTRICITY BOUGHT

2553.00	2571.00	2682.00	2724.00	2766.00	1201.62	3858.00	4950.00
5247.00	2618.88	3020.88	2918.88	3224.88	3218.88	3442.88	3236.88
3146.88	3419.88	3386.88	2882.88	3029.88	2942.88	3332.88	3215.88

HOURLY ELECTRICITY SOLD

.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00

```

$CHECK
SON      =      .00000000E+00
EON      =      .20072299E+05
SAID     =      .00000000E+00
EMID     =      .23972066E+05
SUFF     =      .00000000E+00
EUFF     =      .31768505E+05
CON      =      .23277604E+04
CMID     =      .13604122E+04
COFF     =      .14947749E+04
CEB      =      .52154617E+04
CES      =      .00000000E+00
$END
    
```


DAILY COGEN PLANT DATA

PLANT STEAM DEMAND	=	511500.00	LBS
PLANT ELECTRIC DEMAND	=	123303.00	KW-HR
BOILER STEAM	=	243750.00	LBS
COGEN STEAM	=	267750.00	LBS
COGEN ELECTRICITY	=	47490.13	KW-HR
UTILITY ELECTRICITY	=	75812.86	KW-HR
BOILER FUEL COST	= \$	1235.00	
COGEN FUEL COST	= \$	2105.87	
PLANT ELECTRICITY COST	= \$	5215.46	
COGEN ELECTRICITY WORTH	= \$	.00	
PLANT TOTAL ENERGY COST	= \$	8556.34	
COGEN UNIT IS OFF FOR		8	HOURS

15 MIN ELEC DEMAND FROM INPUT

6360.000	6312.000	6360.000	6516.000	6456.000	6444.000	6336.000	6300.000
6312.000	6012.000	5808.000	5880.000	5700.000	6144.000	6132.000	6228.000
6276.000	6288.000	6228.000	6336.000	6336.000	6300.000	6252.000	6408.000
6540.000	6384.000	6600.000	6792.000	6900.000	6888.000	7068.000	7224.000
7200.000	7140.000	6840.000	6468.000	6480.000	6660.000	6816.000	6696.000
6672.000	6636.000	6480.000	6384.000	6012.000	5844.000	6348.000	6552.000
6552.000	6432.000	6264.000	6384.000	6408.000	6612.000	6816.000	6936.000
6864.000	6744.000	6672.000	6348.000	6432.000	6384.000	6396.000	6528.000
6528.000	6312.000	6396.000	6216.000	6060.000	6336.000	6300.000	6360.000
6372.000	6192.000	6312.000	6252.000	6240.000	6012.000	5940.000	6132.000
6156.000	6168.000	6492.000	6468.000	6684.000	6684.000	6708.000	6504.000
6648.000	6672.000	6528.000	6528.000	6552.000	6456.000	6480.000	6684.000

CALC HOURLY ELEC DEMAND FROM ABOVE INPUT

6387.000	6384.000	6003.000	6051.000	6282.000	6324.000	6579.000	7020.000
6912.000	6663.000	6543.000	6189.000	6408.000	6693.000	6657.000	6435.000
6363.000	6264.000	6282.000	6081.000	6321.000	6645.000	6594.000	6543.000

STEAM DEMAND IN 1000 CU FT OF NAT GAS FROM INPUT

.000	82.000	90.000	100.000	101.000	102.000	90.000	82.000
85.000	108.000	88.000	87.000	81.000	82.000	81.000	88.000
89.000	90.000	96.000	88.000	89.000	85.000	90.000	94.000

HOURLY COGEN PLANT DATA

HOUR	STEAM DEMAND (LB/HR)	ELECTRICITY DEMAND (KW)	STEAM FROM COGEN (LB/HR)	ELECTRICITY FROM COGEN (KW)	STEAM FROM ROTHER (LB/HR)	ELECTRICITY BOUGHT (KW)	ELECTRICITY SOLD (KW)	BOILER FUEL COST (\$)	COGEN FUEL COST (\$)
1	.00	6387.00	.00	.00	.00	6387.00	.00	.00	.00
2	61500.00	6384.00	17100.00	3060.12	44400.00	3323.88	.00	224.96	134.41
3	67500.00	6003.00	17100.00	3060.12	50400.00	2942.88	.00	255.36	134.41
4	75000.00	6051.00	17100.00	3060.12	57900.00	2990.88	.00	293.36	134.41
5	75750.00	6222.00	17100.00	3060.12	58650.00	3221.88	.00	297.16	134.41
6	76500.00	6324.00	17100.00	3060.12	59400.00	3263.88	.00	300.96	134.41
7	67500.00	6579.00	17100.00	3060.12	50400.00	3518.88	.00	255.36	134.41
8	61500.00	7020.00	17100.00	3060.12	44400.00	3959.88	.00	224.96	134.41
9	63750.00	6912.00	17100.00	3060.12	46650.00	3851.88	.00	236.36	134.41
10	81000.00	6663.00	17100.00	3060.12	63900.00	3602.88	.00	323.76	134.41
11	66000.00	6543.00	17100.00	3060.12	48900.00	3482.88	.00	247.76	134.41
12	65250.00	6189.00	17100.00	3060.12	48150.00	3128.88	.00	243.96	134.41
13	60750.00	6408.00	17100.00	3060.12	43650.00	3347.88	.00	221.16	134.41
14	61500.00	6693.00	17100.00	3060.12	44400.00	3632.88	.00	224.96	134.41
15	60750.00	6657.00	17100.00	3060.12	43650.00	3596.88	.00	221.16	134.41
16	66000.00	6435.00	17100.00	3060.12	48900.00	3374.88	.00	247.76	134.41
17	66750.00	6363.00	17100.00	3060.12	49650.00	3302.88	.00	251.56	134.41
18	67500.00	6264.00	17100.00	3060.12	50400.00	3203.88	.00	255.36	134.41
19	72000.00	6282.00	17100.00	3060.12	54900.00	3221.88	.00	278.16	134.41
20	66000.00	6081.00	17100.00	3060.12	48900.00	3020.88	.00	247.76	134.41
21	66750.00	6321.00	17100.00	3060.12	49650.00	3260.88	.00	251.56	134.41
22	63750.00	6645.00	17100.00	3060.12	46650.00	3584.88	.00	236.36	134.41
23	67500.00	6594.00	17100.00	3060.12	50400.00	3513.88	.00	255.36	134.41
24	70500.00	6543.00	17100.00	3060.12	53400.00	3482.88	.00	270.56	134.41
SUM	1551000.00	154623.00	393300.00	70382.68	1157700.00	84240.31	.00	5865.68	3091.50

NAMelist VARIABLES INPUT TO SUPROUTINE BYSL

```

$INBYSL
IRN      =          +1
ISN      =          +1
PMON     =      .75720000E+04
PMID     =      .73440000E+04
IOFF     =          +9
MIDI     =          +13
MIU2     =          +23
IUN      =          +19
A1       =      .12660000E-01
A2       =      .50500000E+01
A3       =      .41300000E-01
A4       =      .21000000E-02
B1       =      .92900000E-02
B2       =      .65000000E+00
C1       =      .59300000E-02
NCC      =      .18670000E+02
NTAX     =      .19000000E-03
NOM      =      .11000000E+00
NMID     =      .80000000E-01
NOFF     =      .50000000E-01
V        =      .30000000E-01
ICHECK   =          +1
$END

```

HOURLY ELECTRICITY BOUGHT

6387.00	3323.88	2942.88	2990.88	3221.88	3263.88	3518.88	3959.88
3851.88	3602.88	3482.88	3128.88	3347.88	3632.88	3596.88	3374.88
3302.88	3203.88	3221.88	3020.88	3260.88	3584.88	3533.88	3482.88

HOURLY ELECTRICITY SOLD

.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00

```

$CHECK
SON      =      .00000000E+00
EUN      =      .20333299E+05
SMID     =      .00000000E+00
EMID     =      .26963066E+05
SOFF     =      .00000000E+00
EOFF     =      .36943948E+05
CUN      =      .23417448E+04
CMID     =      .15108933E+04
COFF     =      .17382903E+04
CEB      =      .56250439E+04
CES      =      .00000000E+00
$END

```

DAILY COGEN PLANT DATA

PLANT STEAM DEMAND	=	1551000.00	LBS
PLANT ELECTRIC DEMAND	=	154623.00	KW-HR
BOILER STEAM	=	1157700.00	LBS
COGEN STEAM	=	393300.00	LBS
COGEN ELECTRICITY	=	70382.68	KW-HR
UTILITY ELECTRICITY	=	84240.31	KW-HR
BOILER FUEL COST	= \$	5865.68	
COGEN FUEL COST	= \$	3091.50	
PLANT ELECTRICITY COST	= \$	5625.04	
COGEN ELECTRICITY WORTH	= \$	.00	
PLANT TOTAL ENERGY COST	= \$	14582.23	
COGEN UNIT IS OFF FOR		1	HOURS

15 MIN ELEC DEMAND FROM INPUT

6552.000	6528.000	6456.000	6564.000	6612.000	6540.000	6504.000	6288.000
6360.000	6372.000	6324.000	6072.000	6096.000	6048.000	5988.000	6300.000
6492.000	6468.000	6288.000	6504.000	6552.000	6600.000	6552.000	6540.000
6420.000	6276.000	6468.000	6324.000	6516.000	6648.000	6684.000	6672.000
6684.000	6612.000	6576.000	6540.000	6948.000	6828.000	6276.000	6240.000
6660.000	6720.000	6780.000	6720.000	6684.000	6396.000	6732.000	6804.000
6780.000	6924.000	7200.000	7320.000	7428.000	7572.000	7476.000	7320.000
7368.000	7380.000	6924.000	6708.000	6672.000	6684.000	6552.000	6360.000
6300.000	6456.000	6480.000	6660.000	6648.000	6852.000	6924.000	6900.000
6900.000	6708.000	6456.000	6324.000	6132.000	6216.000	6372.000	6468.000
6252.000	6264.000	6492.000	6756.000	6684.000	6696.000	6936.000	6792.000
6636.000	6684.000	6924.000	6756.000	6492.000	6576.000	6708.000	6624.000

CALC HOURLY ELEC DEMAND FROM ABOVE INPUT

6525.000	6486.000	6282.000	6108.000	6438.000	6561.000	6372.000	6630.000
6603.000	6573.000	6720.000	6654.000	7056.000	7449.000	7095.000	6567.000
6474.000	6831.000	6597.000	6297.000	6441.000	6777.000	6750.000	6600.000

STEAM DEMAND IN 1000 CU FT OF NAT GAS FROM INPUT

103.000	93.000	102.000	99.000	101.000	92.000	82.000	89.000
93.000	93.000	96.000	88.000	94.000	91.000	90.000	89.000
89.000	87.000	87.000	92.000	95.000	102.000	103.000	104.000

HOURLY COGEN PLANT DATA

HOOR	STEAM DEMAND (LB/HR)	ELECTRICITY DEMAND (KW)	STEAM FROM COGEN (LB/HR)	ELECTRICITY FROM COGEN (KW)	STEAM FROM BOILER (LB/HR)	ELECTRICITY BOUGHT (KW)	ELECTRICITY SOLD (KW)	BOILER FUEL COST (\$)	COGEN FUEL COST (\$)
1	77250.00	6525.00	17100.00	3060.12	60150.00	3464.88	.00	304.76	134.41
2	69750.00	6486.00	17100.00	3060.12	52650.00	3425.88	.00	266.76	134.41
3	76500.00	6282.00	17100.00	3060.12	59400.00	3221.88	.00	300.96	134.41
4	74250.00	6108.00	17100.00	3060.12	57150.00	3047.88	.00	289.56	134.41
5	75750.00	6438.00	17100.00	3060.12	58650.00	3377.88	.00	297.16	134.41
6	69000.00	6561.00	17100.00	3060.12	51900.00	3500.88	.00	262.96	134.41
7	61500.00	6372.00	17100.00	3060.12	44400.00	3311.88	.00	224.96	134.41
8	66000.00	6630.00	17100.00	3060.12	48900.00	3569.88	.00	247.76	134.41
9	69750.00	6603.00	17100.00	3060.12	52650.00	3542.88	.00	266.76	134.41
10	69750.00	6573.00	17100.00	3060.12	52650.00	3512.88	.00	266.76	134.41
11	72000.00	6720.00	17100.00	3060.12	54900.00	3659.88	.00	278.16	134.41
12	66000.00	6654.00	17100.00	3060.12	48900.00	3593.88	.00	247.76	134.41
13	70500.00	7056.00	17100.00	3060.12	53400.00	3995.88	.00	270.56	134.41
14	68250.00	7449.00	17100.00	3060.12	51150.00	4388.88	.00	259.16	134.41
15	67500.00	7095.00	17100.00	3060.12	50400.00	4034.88	.00	255.36	134.41
16	66750.00	6567.00	17100.00	3060.12	49650.00	3506.88	.00	251.56	134.41
17	66000.00	6474.00	17100.00	3060.12	48900.00	3413.88	.00	247.76	134.41
18	65250.00	6831.00	17100.00	3060.12	48150.00	3770.88	.00	243.96	134.41
19	65250.00	6597.00	17100.00	3060.12	48150.00	3536.88	.00	243.96	134.41
20	69000.00	6297.00	17100.00	3060.12	51900.00	3236.88	.00	262.96	134.41
21	71250.00	6441.00	17100.00	3060.12	54150.00	3380.88	.00	274.36	134.41
22	76500.00	6777.00	17100.00	3060.12	59400.00	3716.88	.00	300.96	134.41
23	77250.00	6750.00	17100.00	3060.12	60150.00	3689.88	.00	304.76	134.41
24	79000.00	6600.00	17100.00	3060.12	60900.00	3539.88	.00	308.56	134.41
SUM	1689000.00	158886.00	410400.00	73442.80	1278600.00	85443.19	.00	6478.24	3225.91

NAMLIST VARIABLES INPUT TO SUBROUTINE BYSL

```

$INBYSL
IKN      =          +1
ISN      =          +1
PMON     =      .75720000E+04
PMID     =      .73440000E+04
IOFF     =          +9
MIU1     =          +13
MIU2     =          +23
ION      =          +19
A1       =      .12660000E-01
A2       =      .50500000E+01
A3       =      .41300000E-01
A4       =      .21000000E-02
B1       =      .92900000E-02
B2       =      .65000000E+00
C1       =      .59300000E-02
KCC      =      .18670000E+02
RTAX     =      .19000000E-03
KUN      =      .11000000E+00
NMIU     =      .80000000E-01
NOFF     =      .50000000E-01
V        =      .30000000E-01
ICHECK   =          +1
$END
    
```

HOURLY ELECTRICITY BOUGHT

3464.88	3425.88	3221.88	3047.88	3377.88	3500.88	3311.88	3569.88
3542.88	3512.88	3659.88	3593.88	3995.88	4388.88	4034.88	3506.88
3413.88	3770.88	3536.88	3236.88	3380.88	3716.88	3689.88	3539.88

HOURLY ELECTRICITY SOLD

.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00

```

$CHECK
SUN      =      .00000000E+00
EUN      =      .22652299E+05
SMIU     =      .00000000E+00
EMID     =      .28787066E+05
SUFF     =      .00000000E+00
EOFF     =      .34003831E+05
CUN      =      .24659973E+04
CMID     =      .16026611E+04
COFF     =      .15999516E+04
CEB      =      .57029540E+04
CES      =      .00000000E+00
$END
    
```

DAILY COGEN PLANT DATA

PLANT STEAM DEMAND = 1689000.00 LBS
 PLANT ELECTRIC DEMAND = 158886.00 KW-HR
 BOILER STEAM = 1278600.00 LBS
 COGEN STEAM = 410400.00 LBS
 COGEN ELECTRICITY = 73442.80 KW-HR
 UTILITY ELECTRICITY = 85443.19 KW-HR
 BOILER FUEL COST = \$ 6478.24
 COGEN FUEL COST = \$ 3225.91
 PLANT ELECTRICITY COST = \$ 5702.95
 COGEN ELECTRICITY WORTH = \$.00
 PLANT TOTAL ENERGY COST = \$ 15407.11
 COGEN UNIT IS OFF FOR 0 HOURS

15 MIN ELEC DEMAND FROM INPUT

6463.000	6588.000	6480.000	6492.000	6448.000	6660.000	6396.000	6024.000
6096.000	6156.000	6204.000	6024.000	5580.000	5724.000	5892.000	6024.000
5964.000	6072.000	6060.000	6048.000	5868.000	6168.000	6408.000	6372.000
6240.000	6324.000	6540.000	6672.000	6624.000	6984.000	7152.000	7080.000
7164.000	7236.000	7296.000	7320.000	7344.000	7032.000	6948.000	6840.000
6792.000	6696.000	6552.000	6408.000	6324.000	6408.000	6804.000	6324.000
6876.000	6768.000	6648.000	6948.000	7260.000	6996.000	7188.000	7044.000
6804.000	6804.000	6576.000	6384.000	6504.000	6480.000	6372.000	6516.000
6284.000	6180.000	6504.000	6312.000	6504.000	6828.000	6720.000	6804.000
6684.000	6396.000	6204.000	6156.000	5916.000	5952.000	6204.000	6224.000
6356.000	6312.000	6252.000	6552.000	6576.000	6408.000	6456.000	6468.000
6504.000	6552.000	6516.000	6396.000	6432.000	6504.000	6300.000	6470.000

CALC HOURLY ELEC DEMAND FROM ABOVE INPUT

6507.000	6432.000	6120.000	5805.000	6036.000	6204.000	6444.000	6960.000
7254.000	7041.000	6612.000	6591.000	6810.000	7122.000	6642.000	6468.000
6321.000	6714.000	6360.000	6075.000	6363.000	6477.000	6492.000	6414.000

STEAM DEMAND IN 1000 CU FT OF NAT GAS FROM INPUT

105.000	91.000	106.000	98.000	90.000	86.000	84.000	84.000
91.000	81.000	92.000	93.000	93.000	101.000	94.000	94.000
88.000	98.000	106.000	104.000	102.000	99.000	102.000	101.000

HOURLY COGEN PLANT DATA

HOOR	STEAM DEMAND (LB/HR)	ELECTRICITY DEMAND (KW)	STEAM FROM COGEN (LB/HR)	ELECTRICITY FROM COGEN (KW)	STEAM FROM BOILER (LB/HR)	ELECTRICITY BOUGHT (KW)	ELECTRICITY SOLD (KW)	BOILER FUEL COST (\$)	COGEN FUEL COST (\$)
1	78750.00	6507.00	17100.00	3060.12	61650.00	3446.88	.00	312.36	134.41
2	68250.00	6432.00	17100.00	3060.12	51150.00	3371.88	.00	259.16	134.41
3	79500.00	6120.00	17100.00	3050.12	62400.00	3059.88	.00	316.16	134.41
4	73500.00	5805.00	17100.00	3060.12	56400.00	2744.88	.00	285.76	134.41
5	67500.00	6076.00	17100.00	3050.12	50400.00	2975.88	.00	255.36	134.41
6	64500.00	6204.00	17100.00	3060.12	47400.00	3143.88	.00	240.16	134.41
7	63000.00	6444.00	17100.00	3060.12	45900.00	3383.88	.00	232.56	134.41
8	63000.00	6960.00	17100.00	3050.12	45900.00	3899.88	.00	232.56	134.41
9	60750.00	7254.00	17100.00	3060.12	43650.00	4193.88	.00	221.16	134.41
10	60750.00	7041.00	17100.00	3050.12	43650.00	3980.88	.00	221.16	134.41
11	69000.00	6612.00	17100.00	3060.12	51900.00	3551.88	.00	262.96	134.41
12	69750.00	6591.00	17100.00	3050.12	52650.00	3530.88	.00	266.76	134.41
13	69750.00	6810.00	17100.00	3060.12	52650.00	3749.88	.00	266.76	134.41
14	75750.00	7122.00	17100.00	3060.12	58650.00	4061.88	.00	297.16	134.41
15	70500.00	6642.00	17100.00	3060.12	53400.00	3581.88	.00	270.56	134.41
16	71250.00	6468.00	17100.00	3060.12	54150.00	3407.88	.00	274.36	134.41
17	66000.00	6321.00	17100.00	3060.12	48900.00	3260.88	.00	247.76	134.41
18	73500.00	6714.00	17100.00	3060.12	56400.00	3653.88	.00	285.76	134.41
19	79500.00	6360.00	17100.00	3060.12	62400.00	3299.88	.00	316.16	134.41
20	78000.00	6075.00	17100.00	3060.12	60900.00	3014.88	.00	308.56	134.41
21	76500.00	6363.00	17100.00	3060.12	59400.00	3302.88	.00	300.96	134.41
22	74250.00	6477.00	17100.00	3060.12	57150.00	3416.88	.00	289.56	134.41
23	76500.00	6492.00	17100.00	3060.12	59400.00	3431.88	.00	300.96	134.41
24	75750.00	6414.00	17100.00	3060.12	58650.00	3353.88	.00	297.16	134.41
SUM	1705500.00	156264.00	410400.00	73442.80	1295100.00	82821.19	.00	6561.84	3225.91

NAMLIST VARIABLES INPUT TO SUBROUTINE BYSL

```

$INBYSL
IRN      =          +1
ISM      =          +1
PMON     =      .75720000E+04
PMID     =      .73440000E+04
IDFF     =          +9
MIU1     =          +13
MID2     =          +23
ION       =          +19
A1        =      .12660000E-01
A2        =      .50500000E+01
A3        =      .41300000E-01
A4        =      .21000000E-02
B1        =      .92900000E-02
B2        =      .65000000E+00
C1        =      .59300000E-02
HCC       =      .18670000E+02
RTAX     =      .19000000E-03
RON      =      .11000000E+00
RMID     =      .80000000E-01
ROFF     =      .50000000E-01
V         =      .30000000E-01
ICHECK   =          +1
SEND
    
```

HOURLY ELECTRICITY BOUGHT

3446.88	3371.88	3059.88	2744.88	2975.88	3143.88	3383.88	3899.88
4193.88	3980.88	3551.88	3530.88	3749.88	4061.88	3581.88	3407.88
3260.88	3653.88	3299.88	3014.88	3302.88	3416.88	3431.88	3353.88

HOURLY ELECTRICITY SOLD

.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00

```

$CHECK
SON      =      .00000000E+00
EON      =      .2126A299E+05
SMIU     =      .00000000E+00
EMID     =      .27980066E+05
SOFF     =      .00000000E+00
EOFF     =      .33574831E+05
CON      =      .23917351E+04
CMID     =      .15620599E+04
COFF     =      .15797663E+04
CEB      =      .55674072E+04
CES      =      .00000000E+00
SEND
    
```

DAILY COGEN PLANT DATA

PLANT STEAM DEMAND = 1705500.00 LBS
 PLANT ELECTRIC DEMAND = 156264.00 KW-HR
 BOILER STEAM = 1295100.00 LBS
 COGEN STEAM = 410400.00 LBS
 COGEN ELECTRICITY = 73442.80 KW-HR
 UTILITY ELECTRICITY = 82821.19 KW-HR
 BOILER FUEL COST = \$ 6561.84
 COGEN FUEL COST = \$ 3225.91
 PLANT ELECTRICITY COST = \$ 5567.41
 COGEN ELECTRICITY WORTH = \$.00
 PLANT TOTAL ENERGY COST = \$ 15355.16
 COGEN UNIT IS OFF FOR 0 HOURS

15 MIN ELEC DEMAND FROM INPUT

6288.000	6108.000	6312.000	6168.000	6264.000	6312.000	6312.000	6264.000
6060.000	6204.000	6144.000	5868.000	5928.000	5928.000	6288.000	6348.000
6360.000	6276.000	6336.000	6408.000	6072.000	6072.000	6156.000	6240.000
6384.000	6372.000	6180.000	6312.000	6720.000	6504.000	6348.000	6372.000
6348.000	6372.000	6072.000	5988.000	5964.000	6096.000	5892.000	6312.000
6504.000	6300.000	6528.000	6552.000	6468.000	6540.000	6336.000	6804.000
6900.000	7116.000	7140.000	6720.000	6372.000	6456.000	6348.000	6060.000
6192.000	6204.000	6060.000	6036.000	6204.000	6000.000	5784.000	5856.000
5892.000	6240.000	6336.000	6252.000	6264.000	6264.000	6084.000	6348.000
6372.000	6180.000	6360.000	6108.000	5676.000	5868.000	5856.000	5688.000
5748.000	5580.000	5344.000	5544.000	5556.000	5376.000	5916.000	5940.000
5712.000	5652.000	5760.000	5652.000	5580.000	5436.000	5580.000	5592.000

CALC HOURLY ELEC DEMAND FROM ABOVE INPUT

6219.000	6288.000	6069.000	6123.000	6345.000	6135.000	6312.000	6486.000
6195.000	6066.000	6471.000	6537.000	6969.000	6309.000	6123.000	5961.000
6180.000	6240.000	6255.000	5772.000	5568.000	5697.000	5694.000	5547.000

STEAM DEMAND IN 1000 CU FT OF NAT GAS FROM INPUT

109.000	109.000	109.000	115.000	110.000	97.000	88.000	86.000
86.000	92.000	97.000	102.000	97.000	92.000	85.000	92.000
91.000	108.000	109.000	111.000	112.000	116.000	111.000	117.000

HOURLY COGEN PLANT DATA

HOUR	STEAM DEMAND (LB/HR)	ELECTRICITY DEMAND (KW)	STEAM FROM COGEN (LB/HR)	ELECTRICITY FROM COGEN (KW)	STEAM FROM ROILER (LB/HR)	ELECTRICITY BOUGHT (KW)	ELECTRICITY SOLD (KW)	ROILER FUEL COST (\$)	COGEN FUEL COST (\$)
1	81000.00	6219.00	17100.00	3060.12	63900.00	3158.88	.00	323.76	134.41
2	81750.00	6288.00	17100.00	3060.12	64650.00	3227.88	.00	327.56	134.41
3	81750.00	6069.00	17100.00	3060.12	64650.00	3008.88	.00	327.56	134.41
4	86250.00	6123.00	17100.00	3060.12	69150.00	3062.88	.00	350.36	134.41
5	82500.00	6345.00	17100.00	3060.12	65400.00	3284.88	.00	331.36	134.41
6	72750.00	6135.00	17100.00	3060.12	55650.00	3074.88	.00	281.96	134.41
7	68000.00	6312.00	17100.00	3060.12	48900.00	3251.88	.00	247.76	134.41
8	64500.00	6486.00	17100.00	3060.12	47400.00	3425.88	.00	240.16	134.41
9	64500.00	6195.00	17100.00	3060.12	47400.00	3134.88	.00	240.16	134.41
10	69000.00	6066.00	17100.00	3060.12	51900.00	3005.88	.00	262.96	134.41
11	72750.00	6471.00	17100.00	3060.12	55650.00	3410.88	.00	281.96	134.41
12	76500.00	6537.00	17100.00	3060.12	59400.00	3476.88	.00	300.96	134.41
13	72750.00	6469.00	17100.00	3060.12	55650.00	3908.88	.00	281.96	134.41
14	69000.00	6309.00	17100.00	3060.12	51900.00	3248.88	.00	262.96	134.41
15	63750.00	6123.00	17100.00	3060.12	46650.00	3062.88	.00	236.36	134.41
16	69000.00	5961.00	17100.00	3060.12	51900.00	2900.88	.00	262.96	134.41
17	65250.00	6180.00	17100.00	3060.12	51150.00	3119.88	.00	259.16	134.41
18	82000.00	6240.00	17100.00	3060.12	63900.00	3179.88	.00	323.76	134.41
19	81750.00	6255.00	17100.00	3060.12	64650.00	3194.88	.00	327.56	134.41
20	83250.00	5772.00	17100.00	3060.12	66150.00	2711.88	.00	335.16	134.41
21	84000.00	5568.00	17100.00	3060.12	66900.00	2507.88	.00	338.96	134.41
22	87000.00	5697.00	17100.00	3060.12	69900.00	2636.88	.00	354.16	134.41
23	83250.00	5694.00	17100.00	3060.12	66150.00	2633.88	.00	335.16	134.41
24	87750.00	5547.00	17100.00	3060.12	70650.00	2486.88	.00	357.96	134.41
SUM	1830000.00	147561.00	410400.00	73442.80	1419600.00	74118.19	.00	7192.64	3225.91

NAMLIST VARIABLES INPUT TO SUBROUTINE BYSL

```

$INBYSL
IRN      =          +1
ISN      =          +1
PRON     =      .75720000E+04
PRIU     =      .73440000E+04
IOFF     =          +9
MIU1     =          +13
MIU2     =          +23
IOM      =          +19
A1       =      .12660000E-01
A2       =      .50500000E+01
A3       =      .41300000E-01
A4       =      .21000000E-02
B1       =      .92900000E-02
B2       =      .65000000E+00
C1       =      .59300000E-02
NCC      =      .18670000E+02
NTAX     =      .19000000E-03
NOM      =      .11000000E+00
NMID     =      .80000000E-01
NOFF     =      .50000000E-01
V        =      .30000000E-01
ICHECK   =          +1
$END
    
```

HOURLY ELECTRICITY BOUGHT

3158.88	3227.88	3008.88	3062.88	3284.88	3074.88	3251.88	3425.88
3134.88	3005.88	3410.88	3476.88	3908.88	3248.88	3062.88	2900.88
3119.88	3179.88	3194.88	2711.88	2507.88	2636.88	2633.88	2486.88

HOURLY ELECTRICITY SOLD

.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00

```

$CHECK
$UN      =      .00000000E+00
EON      =      .18707299E+05
SMID     =      .00000000E+00
EMID     =      .24293066E+05
SOFF     =      .00000000E+00
EUFF     =      .31117831E+05
CON      =      .22546234E+04
CMID     =      .13765621E+04
CJFF     =      .14641593E+04
CEB      =      .51275370E+04
CES      =      .00000000E+00
$END
    
```

DAILY COGEN PLANT DATA

PLANT STEAM DEMAND	=	1830000.00	LBS
PLANT ELECTRIC DEMAND	=	147561.00	KW-HR
BOILER STEAM	=	1419600.00	LBS
COGEN STEAM	=	410400.00	LBS
COGEN ELECTRICITY	=	73442.80	KW-HR
UTILITY ELECTRICITY	=	74118.19	KW-HR
BOILER FUEL COST	= \$	7192.64	
COGEN FUEL COST	= \$	3225.91	
PLANT ELECTRICITY COST	= \$	5127.54	
COGEN ELECTRICITY WORTH	= \$	.00	
PLANT TOTAL ENERGY COST	= \$	15546.09	
COGEN UNIT IS OFF FOR		0	HOURS

15 MIN ELEC DEMAND FROM INPUT

5124.000	5160.000	5088.000	5004.000	5340.000	5388.000	5412.000	5460.000
5460.000	5292.000	5352.000	5124.000	4908.000	5184.000	5256.000	5220.000
5220.000	5256.000	5232.000	5244.000	5232.000	5232.000	5220.000	5244.000
5364.000	5292.000	4992.000	4860.000	4908.000	5076.000	5100.000	5112.000
4968.000	4824.000	4848.000	4812.000	4948.000	4860.000	4932.000	4860.000
4728.000	4908.000	4812.000	4776.000	4968.000	4788.000	5028.000	4896.000
4716.000	4932.000	5172.000	5100.000	5328.000	5280.000	5160.000	5280.000
5244.000	5052.000	5256.000	5232.000	5004.000	5208.000	4908.000	4656.000
4752.000	4764.000	4572.000	4776.000	4812.000	4920.000	5076.000	5076.000
4908.000	5244.000	5112.000	5112.000	5220.000	5040.000	5184.000	5340.000
5064.000	5292.000	5268.000	5136.000	5232.000	5208.000	5112.000	4992.000
5052.000	4860.000	4656.000	4668.000	4392.000	4620.000	4404.000	4260.000

CALC HOURLY ELEC DEMAND FROM ABOVE INPUT

5094.000	5400.000	5307.000	5142.000	5238.000	5232.000	5127.000	5049.000
4863.000	4875.000	4806.000	4920.000	4980.000	5262.000	5196.000	4944.000
4716.000	4971.000	5094.000	5196.000	5190.000	5136.000	4809.000	4419.000

STEAM DEMAND IN 1000 CU FT OF NAT GAS FROM INPUT

103.000	109.000	109.000	116.000	111.000	97.000	88.000	86.000
86.000	92.000	102.000	92.000	85.000	92.000	91.000	108.000
109.000	111.000	112.000	116.000	111.000	107.000	106.000	101.000

HOURLY COGEN PLANT DATA

HOOR	STEAM DEMAND (LB/HR)	ELECTRICITY DEMAND (KW)	STEAM FROM COGEN (LB/HR)	ELECTRICITY FROM COGEN (KW)	STEAM FROM BOILER (LB/HR)	ELECTRICITY BOUGHT (KW)	ELECTRICITY SOLD (KW)	BOILER FUEL COST (\$)	COGEN FUEL COST (\$)
1	81000.00	5094.00	17100.00	3060.12	63900.00	2033.88	.00	323.76	134.41
2	81750.00	5400.00	17100.00	3060.12	64650.00	2339.88	.00	327.56	134.41
3	81750.00	5307.00	17100.00	3060.12	64650.00	2246.88	.00	327.56	134.41
4	87000.00	5142.00	17100.00	3060.12	69900.00	2081.88	.00	354.16	134.41
5	83250.00	5238.00	17100.00	3060.12	66150.00	2177.88	.00	335.16	134.41
6	72750.00	5232.00	17100.00	3060.12	55650.00	2171.88	.00	281.96	134.41
7	66000.00	5127.00	17100.00	3060.12	48900.00	2066.88	.00	247.76	134.41
8	64500.00	5049.00	17100.00	3060.12	47400.00	1988.88	.00	240.16	134.41
9	64500.00	4863.00	17100.00	3060.12	47400.00	1802.88	.00	240.16	134.41
10	69000.00	4875.00	17100.00	3060.12	51900.00	1814.88	.00	262.96	134.41
11	76500.00	4806.00	17100.00	3060.12	59400.00	1745.88	.00	300.96	134.41
12	69000.00	4920.00	17100.00	3060.12	51900.00	1859.88	.00	262.96	134.41
13	63750.00	4980.00	17100.00	3060.12	46650.00	1919.88	.00	236.36	134.41
14	69000.00	5232.00	17100.00	3060.12	51900.00	2201.88	.00	262.96	134.41
15	68250.00	5196.00	17100.00	3060.12	51150.00	2135.88	.00	259.16	134.41
16	81000.00	4944.00	17100.00	3060.12	63900.00	1883.88	.00	323.76	134.41
17	81750.00	4716.00	17100.00	3060.12	64650.00	1655.88	.00	327.56	134.41
18	83250.00	4971.00	17100.00	3060.12	66150.00	1910.88	.00	335.16	134.41
19	84000.00	5094.00	17100.00	3060.12	66900.00	2033.88	.00	338.96	134.41
20	87000.00	5196.00	17100.00	3060.12	69900.00	2135.88	.00	354.16	134.41
21	83250.00	5190.00	17100.00	3060.12	66150.00	2129.88	.00	335.16	134.41
22	80250.00	5136.00	17100.00	3060.12	63150.00	2075.88	.00	319.96	134.41
23	79500.00	4809.00	17100.00	3060.12	62400.00	1748.88	.00	316.16	134.41
24	75750.00	4419.00	17100.00	3060.12	58650.00	1358.88	.00	297.16	134.41
SUM	1833750.00	120966.00	410400.00	73442.80	1423350.00	47523.19	.00	7211.64	3225.91

NAMelist VARIABLES INPUT TO SUBROUTINE BYSL

```

$INBYSL
IKN      =          +0
ISN      =          +1
PMON     =      .75720000E+04
PMID     =      .73440000E+04
IOFF     =          +9
MID1     =          +13
MID2     =          +23
ION      =          +19
A1       =      .12660000E-01
A2       =      .50500000E+01
A3       =      .41300000E-01
A4       =      .21000000E-02
B1       =      .92900000E-02
B2       =      .65000000E+00
C1       =      .59300000E-02
KCC      =      .18670000E+02
NTAX     =      .19000000E-03
KON      =      .11000000E+00
KPID     =      .80000000E-01
KOFF     =      .50000000E-01
V        =      .30000000E-01
ICHECK   =          +1
SEND
    
```

HOURLY ELECTRICITY BOUGHT

2033.88	2339.88	2246.88	2081.88	2177.88	2171.88	2066.88	1988.88
1802.88	1814.88	1745.88	1859.88	1919.88	2201.88	2135.88	1883.88
1655.88	1910.88	2033.88	2135.88	2129.88	2075.88	1748.88	1358.88

HOURLY ELECTRICITY SOLD

.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00
.00	.00	.00	.00	.00	.00	.00	.00

```

$CHECK
$ON      =      .00000000E+00
EQN      =      .11822299E+05
SMID     =      .00000000E+00
EMID     =      .15431066E+05
SOFF     =      .00000000E+00
EOFF     =      .20269932E+05
CON      =      .18857239E+04
CMID     =      .93070338E+03
COFF     =      .95373814E+03
CEB      =      .37973045E+04
CES      =      .00000000E+00
SEND
    
```

DAILY COGEN PLANT DATA

PLANT STEAM DEMAND	=	1833750.00	LBS
PLANT ELECTRIC DEMAND	=	120966.00	KW-HR
BOILER STEAM	=	1423350.00	LBS
COGEN STEAM	=	410400.00	LBS
COGEN ELECTRICITY	=	73442.80	KW-HR
UTILITY ELECTRICITY	=	47523.19	KW-HR
BOILER FUEL COST	= \$	7211.64	
COGEN FUEL COST	= \$	3225.91	
PLANT ELECTRICITY COST	= \$	3797.30	
COGEN ELECTRICITY WORTH	= \$	.00	
PLANT TOTAL ENERGY COST	= \$	14234.86	
COGEN UNIT IS OFF FOR		0	HOURS

9FIN

APPENDIX VI - Derivation of Capital Cost Factor

The capital cost factor incorporates the costs of interest, property taxes and insurance. These three elements of the capital cost factor are treated in turn in the following.

Interest factor

The derivation of this factor is based on the assumption that interest is paid each year on the balance of the loan. The balance on the loan each year is calculated by deducting an amount equal to the average annual loan amount from the previous balance. Consider a loan of \$100 made for three years at an interest rate of 5%. The average annual loan amount is

$$\frac{\$100}{3} \text{ or } \$33.33/\text{yr.}$$

The interest on this loan is then

$$\text{Interest during the first year} = (0.05) (100) = \$5$$

$$\text{Interest during the second year} = (0.05) (100 - 33.33) = 3.33$$

$$\text{Interest during the third year} = (0.05) (66.67 - 33.33) = 1.67$$

and the average interest during three years is $\frac{5+3.33+1.67}{3}$ or \$3.33.

This average interest may be also obtained from the relation

$$\frac{i}{2} \times \frac{n+1}{n}$$

In the case of the loan cited above where n is the number of years to repay the loan and i is the annual interest rate.

$$\begin{aligned} \text{Average interest rate} &= \frac{0.05}{2} + \frac{3+1}{3} \\ &= 0.0333 \end{aligned}$$

and the average interest on the \$100 loan over three years is 0.0333×100 . or \$3.33.

In this study the life of all systems was assumed to be 20 yrs, i.e., $n = 20$, which is also taken as the repayment period for the capital investment in the equipment. The interest for the equipment loan is taken as 15%, fixed over the 20-year repayment period. The interest factor is then

$$\begin{aligned} f_i &= \frac{0.15}{2} \times \frac{20+1}{20} \\ &= 0.07875 \\ &= 0.07875 \end{aligned}$$

Property tax factor

This factor is based on the assumption of straight line depreciation for one-half of the useful life of the equipment, thereafter the book value of the equipment is fixed at one-half its original cost. The resulting general equation for the tax factor is

$$f_t = \frac{A(5n+2)(0.25)t}{8n}$$

where A is the book value at end of year
 n is the useful life
 t is the tax rate

For this study $n = 20$ $t = 0.048$

$$\begin{aligned} f_t &= \frac{1}{(8 \times 20)} (5 \times 20 + 2)(0.25 \times 0.048) \\ &= 0.00765 \end{aligned}$$

Insurance factor

The insurance rate is assumed to be 5¢ per \$100 of investment, hence the insurance factor is 0.0005.

Capital cost factor

The capital cost factor as used for the economic evaluation of the alternative systems of this report is simply the sum of the interest, property tax, and insurance factors, hence

$$\begin{aligned} f &= f_i + f_t + f_{ins} \\ &= 0.07875 + 0.00765 + 0.0005 \\ &= 0.0869 \end{aligned}$$

APPENDIX VII - Energy and Mass Balance for Multi-effect Evaporation

The energy and mass balance for a multi-effect evaporator requires a trial and error procedure based on predetermined temperatures for the evaporation process in each effect. A five-effect, forward feed evaporator with preheaters is shown schematically with the required temperatures in Figure A-VII-1. An example energy and mass balance is shown in Table A-VII-1, with the flow diagram for the calculation procedure given in Figure A-VII-2.

Figure A-VII-1. Schematic diagram with temperatures for a five-effect, forward feed evaporator with seven stages of preheat

Table A-VII-1. Energy balance for a five effect thermal evaporator

Effects	Heat In	Heat Out
<u>FIRST</u>		
Steam	$1150.4 S_0$	8575×1142
Feed Juice	$48,872 \times 147.92 \times 0.92$	$40,297 \times 157.95 \times 0.9$
Condensate		$180.07 \times S_0$
	$S_0 =$	9142 lbs/hr
<u>SECOND</u>		
Vapors	8575×1142	$E_2 \times 1136.2$
Conc. Juice	$40,297 \times 157.95 \times 0.9$	$(40,297 - E_2) \times 142.91 \times 0.875$
Feed Juice	$48,872 \times 132.89 \times 0.92$	$48,872 \times 147.92 \times 0.92$
	$E_2 =$	8358
	Conc. Juice =	31,939
<u>THIRD</u>		
Vapors	8358×1136.2	$E_3 \times 1126.1$
Conc. Juice	$31,939 \times 142.91 \times 0.875$	$(31,939 - E_3) \times 117.89 \times 0.84$
Feed Juice	$48,872 \times 107.89 \times 0.92$	$48,872 \times 132.89 \times 0.92$
Condensate	8575×157.95	$16,933 \times 142.91$
	$E_3 =$	7922
	Conc. Juice =	24,017
<u>FOURTH</u>		
Vapors	7922×1126.1	$E_4 \times 1117.9$
Conc. Juice	$24,017 \times 117.89 \times 0.84$	$(24,017 - E_4) \times 97.90 \times 0.77$
Feed Juice	$48,872 \times 87.92 \times 0.92$	$48,872 \times 107.89 \times 0.92$
Condensate	$16,933 \times 142.91$	$24,855 \times 117.89$
	$E_4 =$	7746
	Conc. Juice =	16,271

Table A-VII-1. Continued

Effects	Heat In	Heat Out
<u>FIFTH</u>		
Vapors	7746×1117.9	$E_5 \times 1109.5$
Conc. Juice	$16,271 \times 97.9 \times 0.77$	$(16,271 - E_5) \times 77.94 \times 0.67$
Feed Juice	$48,872 \times 67.94 \times 0.92$	$48,872 \times 87.92 \times 0.92$
Condensate	$24,855 \times 117.89$	$32,601 \times 97.90$
	$E_5 =$	7446
	Conc. Juice =	8825
	Sum of Evaporation =	40,047
	Steam Economy =	$40,047 \div 9142 = 4.38$

Figure A-VII-2. Logic diagram for heat and material balances

Mass balance. The mass balance for the furnace/dryer drum system as shown in Figures 14a and 14b of Section 5-4 may be expressed as

$$\text{total mass flow in} = \text{total mass flow out}$$

where the total mass flow in consists of fuel (F), air (A), and peel press cake (P). The total mass flow out consists of dried solid product (M), water vapor (W), gaseous carbon dioxide (C), the nitrogen of stoichiometric combustion air (N), and excess air (E). The amount of water evaporated from the peel feed is taken as 60,000 lb/hr. The products of combustion may be expressed in terms of the natural gas fuel flow rate

$$\begin{aligned} \text{hence} \quad W &= 1.87F \\ C &= 2.52F \\ N &= 11F \\ \text{and} \quad E &= A - 14.39F \end{aligned} \quad (\text{Eq. VIII-1})$$

Noting that

$$\text{Peel press cake feed, i.e., } P = M + 60,000 \quad (\text{Eq. VIII-2})$$

and that

$$\text{solid material in} = \text{dried product out}$$

since inlet moisture of press cake is 77% and exit moisture of product is 8%

$$(1.00 - 0.77) P = (1.00 - 0.08) M$$

simplifying gives

$$P = 4 M$$

substituting into Eq. VIII-2 gives

$$P = 80,000 \text{ lb/hr}$$

and

$$M = 20,000 \text{ lb/hr}$$

The humidity of the exhaust gaseous product of the dryer drum is given by

$$\text{absolute humidity} = \frac{\text{mass of water vapor}}{\text{mass of dry gas}} \quad (\text{Eq. VIII-3})$$

The mass of water vapor may be expressed in terms of the fuel flow as given by Eqns. VIII-1 and by the amount of water evaporated from the peel feed, hence

$$\text{mass of water vapor} = 1.87F + 60,000$$

The mass of dry gas is the sum of the mass components of the exhaust gas, not including the water vapor, hence

$$\text{mass of dry gas} = \text{mass of (carbon dioxide + nitrogen + excess air)}$$

or in terms of the inflow quantities

$$\text{mass of dry gas} = 2.52F + 11F + (A - 14.39F)$$

simplifying

$$\text{mass of dry gas} = A - 0.87F$$

Upon substitution in Eq. VIII-3, the expressions above become

$$\text{absolute humidity} = \frac{1.87F + 60,000}{A - 0.87F} \quad (\text{Eq. VIII-4})$$

The absolute humidity may be found from standard psychometric tables with experimental measurements of the wet bulb and dry bulb temperatures of the exhaust stream, which for nominal operation of the peel dryer system, yields an absolute humidity of 0.79 lb water vapor per lb dry air. Hence, Eq. VIII-4 becomes

$$A - 3.24F = 75.98 \quad (\text{Eq. VIII-5})$$

Therefore, the air flow rate into the dryer system can be found from experimental values of more readily measured parameters.

Energy balance. An energy balance for the furnace/dryer drum system shown in Figure 15 of section 5.4 may be expressed as

$$\text{total energy in} = \text{total energy out}$$

or in terms of the constituents of the inflow and outflow streams

$$Q_c F = Mh_m + (W + 60000) h_w$$

$$+ Nh_n + Ch_c + Eh_e + H_L$$

(Eq VIII-6)

where F, P, M, W, N, C, and E are as defined for Eqn. VIII-1; Q_c is the higher heating value (HHV) of the fuel; h_m , h_w , h_n , h_c , and h_e are the enthalpies of the constituents of the exit gas stream relative to the inlet reference temperature of 60°F; and H_L is the heat loss from the dryer drum which is assumed to be 2% of the fuel heat input. Using appropriate temperature measurements to determine the enthalpies, the energy and mass equations may be solved simultaneously to obtain parameters given in Table 8 of section 5.4.

REFERENCES

- (1) Kelso, L. R., Rowan, C. M., and Holladay, K. L., "The Economics of Using Mechanical Vapor Recompression Evaporators to Concentrate Orange Juice," 1980.
- (2) "Evaporation/A Prime Target for Industrial Energy Conservation," ERDA Report C00-2870, Vols. 1 and 2, 1977.
- (3) Dockendorff, J. D. and Cheng, P. J., "Energy Conscious Evaporators," Chemical Engineering Progress, May, 1976.
- (4) "Energy Conservation in Citrus Fruit Processing," Research Proposal to the U.S. Department of Energy from Sunkist Growers, Inc., Ontario, CA., 1978.
- (5) Leo, M. A., et al, "Energy Conservation in Citrus Fruit Processing - Tech. Prog. Rep. No. 2," DOE/CS/40263-T2, March 15, 1981.
- (6) Data Resources Incorporated (DRI) Energy Review 1981. Lexington, Massachusetts.
- (7) Science Applications Incorporated (SAI), "Solar Thermal Cost Goal Fuel Price Projections," Preliminary report to SERI, May 15, 1981.