

Potential for Cogeneration of Heat and Electricity in California Industry - Phase I Final Report

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May 1, 1978

Prepared for
State of California
Energy Resources Conservation and
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Jet Propulsion Laboratory
California Institute of Technology
Pasadena, California

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California Institute of Technology, for the
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ABSTRACT

This report summarizes the results of a Phase I study conducted by the Jet Propulsion Laboratory for the California Energy Resources Conservation and Development Commission to determine the potential for cogeneration of heat and electricity in California industry.

The primary effort of the Phase I study was to conduct an industrial survey of 12 selected plants in the State of California. Information collected during the study was organized into four categories: technical, economic, environmental, and institutional.

In this Phase I study the technical aspects of industrial cogeneration are examined on a site-specific basis. Following this work, a Phase II study will investigate further and analyze the site-specific economics, environmental constraints, and institutional barriers that impact industrial cogeneration.

The Project Manager was Herbert S. Davis. Participating in the study were Vincent C. Moretti, who performed the technical analysis, and Robert M. Gurfield and Marie L. Slonski who were responsible for the survey organization as well as the economic and institutional factors. The duration of the study was approximately five months and involved 10 man-months of effort. The Project Coordinator was Phil Nesewich of the California Energy Resources Conservation and Development Commission.

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Industrial Companies

California Paperboard Corporation
California Portland Cement Company
Exxon Company, U.S.A.
Hunt-Wesson Foods, Inc.
Husky Oil Company
Kaiser Steel Corporation
Kelco Company
Owens-Illinois, Inc.
Simpson Paper Company
Simpson Timber Company
Spreckels Sugar Company
Union Oil Company

Electric Utilities

City of Santa Clara Electric Department
Los Angeles Department of Water and Power
Pacific Gas and Electric Company
San Diego Gas and Electric Company
Southern California Edison Company

We also wish to express our appreciation to R. Manvi and D. S. Pivrotto for valuable discussions and to the Jet Propulsion Laboratory Cogeneration Review Board for its guidance in this effort:

J. M. Spiegel, chairman, and members D. S. Hess, F. R. Livingston, R. L. Phen, J. A. Plamondon, and R. P. O'Toole.

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SECTION I

EXECUTIVE SUMMARY

More energy is required to produce industrial process heat and electricity separately than would be required to produce them in combination with each other. Combined generation, or cogeneration* of heat and electricity is, therefore, one strategy for energy conservation. Prompted by recent increases in electricity and fuel costs, industry is now reconsidering this once popular concept.

A. OBJECTIVE AND SCOPE

The objective of this Phase I study was to conduct an industrial survey within the State of California to:

- (1) Determine the feasibility and desirability of industrial cogeneration and the utilization of waste heat from electricity generating plants at selected sites, and
- (2) Determine the economic, institutional and environmental barriers to industrial cogeneration of heat and electricity at selected sites.

Previous studies have estimated industry-wide and nation-wide potentials for industrial cogeneration. In contrast to these studies, the scope of this investigation was limited to 12 plants, all of which are located in the State of California. Regional, local, and individual differences in attitudes toward the economic, environmental, and institutional issues of cogeneration can thus be explicitly recognized.

The 12 plants selected for the industrial survey are listed in Table 1-1 with the site selection criteria. The relative locations of these sites throughout the state are illustrated in Figure 1-1.

The sites are a representative, but not unique, selection of California plants having a relatively high consumption of process heat and, therefore, high potentials for cogeneration. The site selection criteria permitted a balanced representation of utility companies and air pollution control districts.

Cogeneration potentials and associated technologies are discussed in this report for each industrial plant from the viewpoint of that plant's operation.

*See Glossary for definitions of this and other relevant terms.

Table 1-1. Selected Cogeneration Sites in California

| Plant | Industry | Location | Selection Criteria | | | | | | | | | | Thermal Energy Use Rank In California | Reported Estimate of Cogeneration Capacity, MWe | |
|-------------------------------|---------------------------------|-------------|--------------------|-----------|--------------------------------|------------------|-----|------|-----------|-----------------|---------|-------------|---------------------------------------|---|-----|
| | | | Type Cogen Cycle | | Air Pollution Control District | Electric Utility | | | | Cogen. Activity | | | | | |
| | | | Topping | Bottoming | | PGE | SCE | SDGE | Municipal | Existing | Planned | Under Study | | | |
| California Paperboard Corp. | Paperboard Products | Santa Clara | X | | Bay Area | | | | X | | | X | | 46 | 10 |
| California Portland Cement Co | Cement Manufacturing | Mojave | | X | Kern Co. | | X | | | | | | X | 3 | 100 |
| Exxon Co., U.S.A | Petroleum Refining | Benecia | X | | Bay Area | X | | | | | | | X | 1 | 40 |
| Hunt-Wesson Foods, Inc | Food Products | Fullerton | X | | South Coast | | X | | | | | X | | 6 | 0 7 |
| Husky Oil Co | Enhanced Oil Recovery | Santa Maria | X | | Santa Barbara Co | X | | | | | | | X | 1 | 300 |
| Kaiser Steel Corp | Steel | Fontana | X | | South Coast | | X | | | | | | X | 4 | 60 |
| Kelco Co. | Organic and Inorganic Chemicals | San Diego | X | | San Diego Co | | | X | | | | | X | 2 | 12 |
| Owens-Illinois, Inc. | Glass Containers | Oakland | | X | Bay Area | X | | | | | | | X | 7 | -- |
| Simpson Paper Co. | Pulp and Paper | Anderson | X | | Shasta Co | X | | | | | | | X | 46 | 19 |
| Simpson Timber Co | Timber | Arcata | X | | Humboldt Co | X | | | | | | | X | 20 | -- |
| Spreckels Sugar Co | Sugar Beet Refining | Manteca | X | | San Joaquin Co | X | | | | X | | | | 5 | 4 2 |
| Union Oil Co | Petroleum Refining | Wilmington | X | | South Coast | | | | | | | | X | 1 | 40 |
| Totals | | | 10 | 2 | -- | 6 | 3 | 1 | 2 | 1 | 4 | 7 | -- | -- | -- |

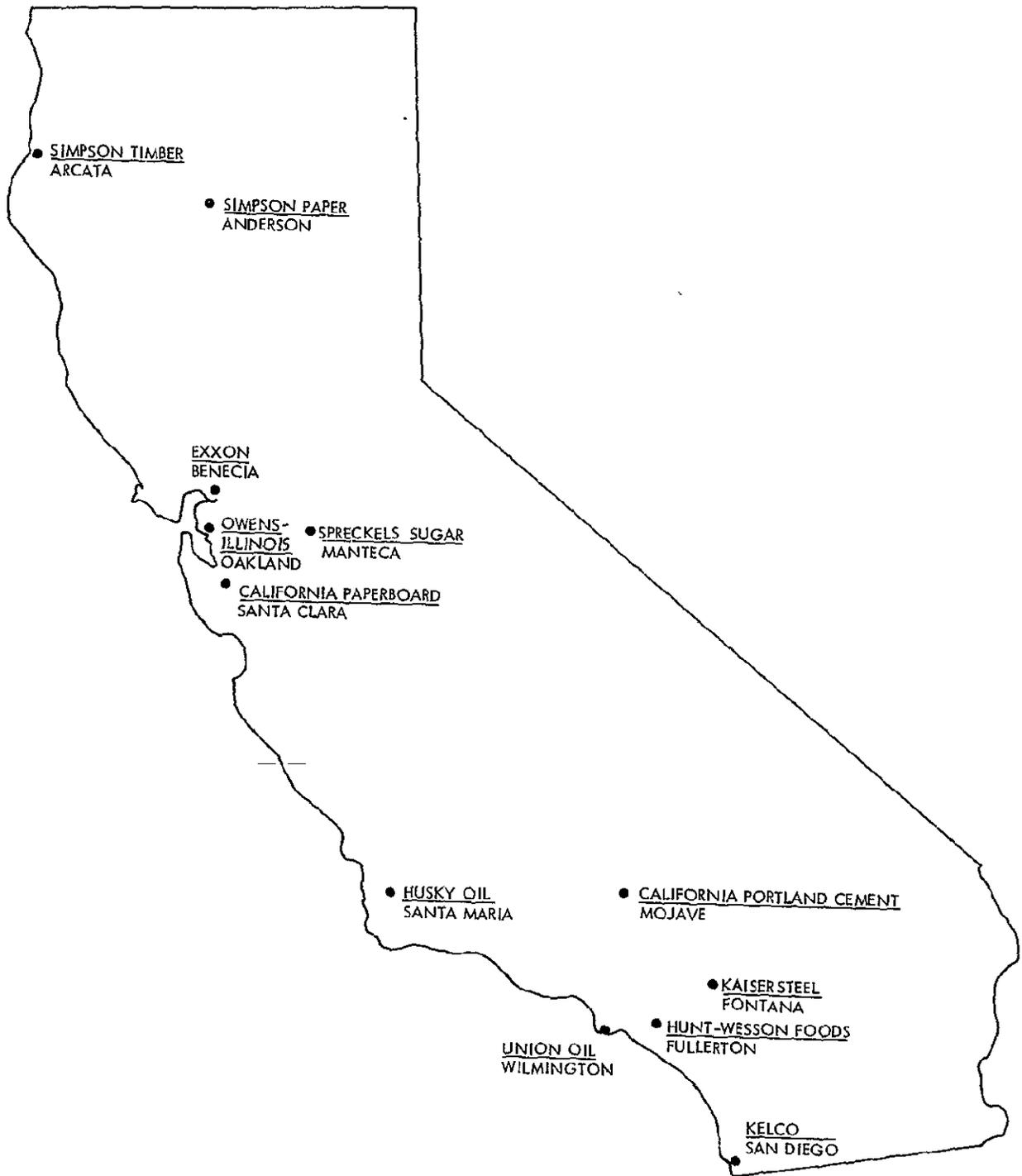


Figure I-1. Selected Cogeneration Site Locations in California

B. FINDINGS

Cogeneration potentials (net energy savings and electric capacities) for the 12 plants surveyed were calculated based on each plant's steam load and assumed cogeneration configuration. The net energy savings ranged up to about 61 percent when compared with a base (noncogenerating) system which meets the total energy demand for each plant.

Energy savings for a variety of cogenerating systems were analyzed for energy impacts considering both topping and bottoming cycles. The analysis considered both gas turbines and steam turbines as prime movers with options for supplemental boiler firing, purchasing electricity, and selling excess by-product power. Results from those cogenerating systems which produced the largest net energy savings are summarized in Table 1-2.

The results of this Phase I study substantiate some of the conclusions of the broader, nationwide studies. Based on the survey results and the technical analysis, it is found that:

- (1) Plant management is generally interested in meeting only its process heat (steam) demand; the production of electricity is of secondary importance.
- (2) Plants with cogeneration potential generally create by-products which can be used as supplemental fuel.
- (3) Energy savings, relative to existing plant operations, of as high as about 61 percent can be achieved with cogeneration systems.
- (4) Near-term implementation of cogeneration is technically feasible; however, significant economic, environmental and institutional issues must first be resolved before industry will regard the concept as desirable.

Major economic, environmental, and institutional issues for each plant are summarized in Table 1-3. Recurrent constraints or barriers to the successful near-term implementation of cogeneration appear in each of these areas. Specifically, it is found that:

- (1) Due to the associated risks and uncertainties, shorter payback periods and higher rates of return are required for cogeneration projects than for alternative investments.
- (2) Confusion and concern exist over the interpretation of and ability to meet air quality regulations as they may apply to industrial cogeneration.
- (3) Fair and equitable rates for wheeling, standby capacity and sale of by-product power remain to be negotiated by industry and the utilities.

Table 1-2. Calculated Cogeneration Potentials at 12 Locations in California

| Plant | Cogeneration System Description | Present System Demand | | Cogeneration System | | | |
|------------------------------------|---------------------------------|-----------------------|------------------------------|---|-------------------------|--|-------------------------------|
| | | Electric MWe | Steam 10 ⁶ Btu/hr | Calculated Energy Requirements 10 ⁶ Btu/hr | | Calculated Cogeneration Potential | |
| | | | | Adjusted* Base System | Net Cogeneration System | Net Energy Savings, 10 ⁶ Btu/hr | Site Generation Capacity, MWe |
| Calif. Paperboard Corp. | T,G | 4.0 | 85 | 224 | 156 | 68 | 12.3 |
| Calif. Portland Cement Co. | B,S-C | 15.8 | 0 | 758 | 635 | 123 | 12.0 |
| Exxon Co., U.S.A. | T,G | 35.0 | 207 | 615 | 433 | 182 | 30.0 |
| Hunt-Wesson Foods, Inc. (c) (o) | T,G | 4.2 | 360 | 968 | 640 | 328 | 50.6 |
| | T,S-B | 2.1 | 36 | 66 | 59 | 7 | 0.8 |
| Husky Oil Co. | T,G | 0.6 | 1115 | 2948 | 2574 | 374 | 163.0 |
| Kaiser Steel Corp. | T,S-B | 104.0 | 1138 | 2128 | 838 | 1290 | 46.0 |
| Kelco Co. | T,G | 6.0 | 178 | 468 | 327 | 141 | 25.9 |
| Owens-Illinois, Inc. | B,S-C | 11.7 | 0 | 540 | 490 | 50 | 4.9 |
| Simpson Paper Co. | T,S-E | 17.0 | 154 | 441 | 427 | 14 | 25.0 |
| Simpson Timber Co. | T,S-B | 4.4 | 9 | 56 | 51 | 5 | 0.6 |
| Spreckels Sugar Co. | T,S-B | 5.0 | 178 | 231 | 231 | ** | 4.2 |
| Union Oil Co. | T,G&S-B | 50.0 | 849 | 1575 | 1095 | 480 | 40.0 |

Key: (c) = Canning season only; (o) off season only * Adjusted for energy displaced by cogeneration
T = Topping cycle ** Already cogenerating
B = Bottoming cycle
G = Gas turbine
S-C = Steam turbine, condensing type
S-B = Steam turbine, back pressure type
S-E = Steam turbine, extraction type

Table 1-3. Economic, Environmental and Institutional Issues

| Company | Issues | | |
|------------------------------------|--|--|---|
| | Economic | Environmental | Institutional |
| California Paperboard Corporation | Projects evaluated separately Accelerated depreciation Seven year depreciation life | Interpreting and meeting air quality regulations | Purchase price for steam Guaranteed long term agreement |
| California Portland Cement Company | Rate of return: 8 - 12% Market conditions important | Interpreting and meeting air quality regulations NO _x , SO ₂ and particulate requirements | Wheeling Standby power charges |
| Exxon Company, U.S.A. | Rate of return: risk dependent Market conditions important Decisions product/process oriented | Interpreting and meeting air quality regulations | Selling price for excess electricity |
| Hunt-Wesson Foods, Inc. | Return on investment: 25% Energy related projects have priority | Interpreting and meeting air quality regulations | Selling price for excess electricity |
| Husky Oil Co. | Accelerated depreciation | Interpreting and meeting air quality regulations | Guaranteed oil supply |
| Kaiser Steel Corporation | Short payback period | Meeting requirements Uncertainty about future requirements | Wheeling |
| Kelco Company | Payback period: 1 - 4 years | Interpreting and meeting air quality regulations | Purchase price for steam |

Table 1-3. Economic, Environmental and Institutional Issues (Continuation 1)

| Company | Issues | | |
|----------------------------|---|---|--|
| | Economic | Environmental | Institutional |
| Owens-Illionis, Inc. | Decisions profit oriented Accelerated depreciation | Interpreting and meeting air quality regulations Uncertainty about future requirements | None |
| Simpson Paper Company | Return on investment: 22-25% Discounted cash flow method Accelerated depreciation | Interpreting and meeting air quality regulations Sulfur content of coal Uncertainty about future requirements | Selling price for excess electricity Standby power charges |
| Simpson Timber Company | Payback period: 4-5 years Priority to large rate of return and small payback period | Meeting requirements requires more energy | Wheeling Standby power charges |
| Spreckels Sugar Company | Return on investment: 20-25% | Sulfur content of oil | None |
| Union Oil Company | Expected return on investment important: ~20% for cogen- eration projects | Interpreting and meeting air quality regulations Rules | Rate structure |

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These issues will be examined in greater detail in Phase II of this study when the effects of specific costs, policies, and regulations will be explored from the perspectives of the utilities and the regulatory agencies as well as industry.

C. RECOMMENDATIONS FOR FUTURE WORK

We recognize the limitations of this study and suggest the following work which will lead to a more complete understanding of the issues. We recommend

- (1) Reexamining industrial plants in California under more stringent analysis paying attention to those plants that were eliminated from consideration in this study. These plants may be suitable candidates for cogeneration when a different set of criteria is applied.
- (2) Examining the energy savings achieved by cogeneration to determine if critical fuels (e.g., natural gas) will be displacing other, less critical fuels (e.g., coal) and determining the implications of this displacement.
- (3) Analyzing in detail the overall system costs, including both fuel and capital costs for industry as well as the utilities.

This study, like other studies, has identified significant economic, environmental, and institutional issues which must be resolved before industry can be expected to implement cogeneration. An in-depth analysis of these important, complex issues is beyond the scope of this Phase I study; however, analysis of some of these issues will be performed in the Phase II study. In particular, the Phase II effort will include:

- (1) Key environmental constraints and possible mitigating measures.
- (2) Proposals for regulatory action.
- (3) Key elements of a cost framework for return on investment analysis for plant-by-plant cogeneration alternatives.
- (4) Environmental and institutional conditions under which industrial cogeneration is viable in the State of California.

SECTION II

SURVEY DATA

A. TECHNICAL ANALYSIS

The analytical method used to quantify the technical potential for cogeneration at each of the 12 plants included in the survey is described in this section. First, a base (noncogenerating) system for which energy is purchased to meet each plant's steam and electrical demand was calculated. A schematic diagram of this base system is illustrated in Figure 2-1. Next, alternative cogeneration systems were analyzed for each site using topping or bottoming cycles which included options for

- (1) Sale of excess by-product power,
- (2) Purchasing electricity (to meet the plant electrical demand), and
- (3) Supplemental boiler firing (to meet the plant steam demand).

These alternative cogeneration systems are described in more detail below.

When the plant steam demand was greater than the electrical demand, those cogeneration systems investigated produced more electricity than was needed on-site. The resulting excess by-product power was then assumed to be available for sale or wheeling with a tie-in to the utility grid. This concept, shown in Figure 2-2 for a gas turbine topping cycle, produced the largest net energy savings for California Paperboard, Hunt-Wesson, Husky Oil, Kelco, and (substituting a steam turbine for the gas turbine) Simpson Paper.

When the cogenerating system does not have sufficient electrical capacity to meet the plant electrical demand, it was assumed that required electricity was purchased. This concept, shown in Figure 2-3 for a steam turbine topping cycle, produced the largest net energy savings for Kaiser Steel, Simpson Timber, Spreckels Sugar, Union Oil, and (substituting a gas turbine for the steam turbine) Exxon. The large energy savings (61%) for Kaiser Steel is due to the fact that 85% of the available blast furnace gas is used for cogeneration.

Plants with processes having high temperature waste heat available were California Portland Cement and Owens-Illinois. A steam turbine bottoming cycle, shown in Figure 2-4, produced the largest net energy savings for these two plants. In bottoming cycle systems, the waste heat can be captured and passed through a counter-flow heat exchanger to generate either steam for plant use or for a steam turbine to generate electricity. Were it not for technical problems created by high temperature contaminated gases, the hot reject gases could, alternatively, be injected directly into a gas turbine (see Figure 2-5).

Figure 2-6 shows a gas turbine topping cycle with supplemental boiler firing. This concept was sized to meet the electrical demand for California Paperboard and Kelco. The net energy savings for these

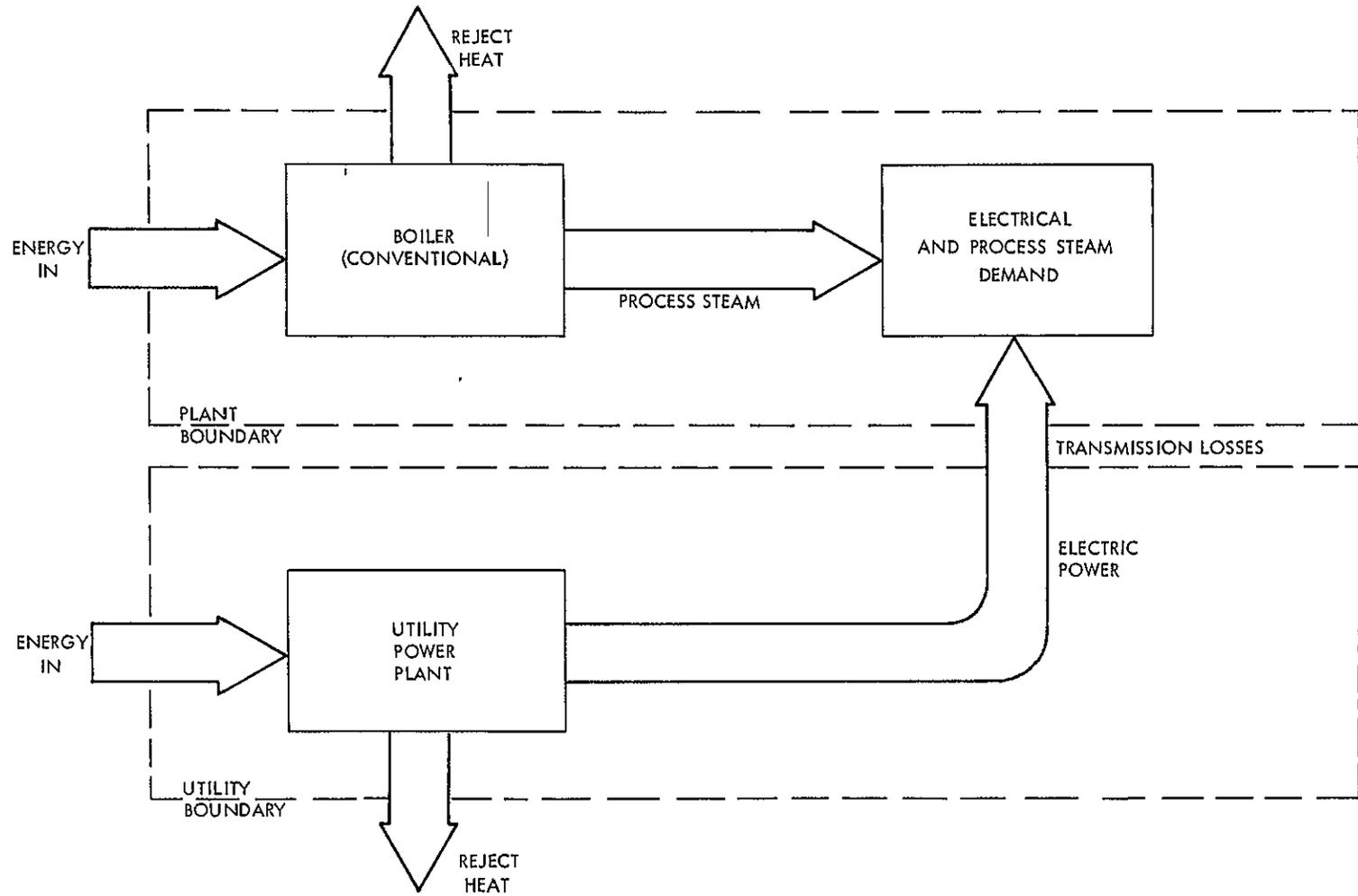


Figure 2-1. Base (Noncogenerating) System

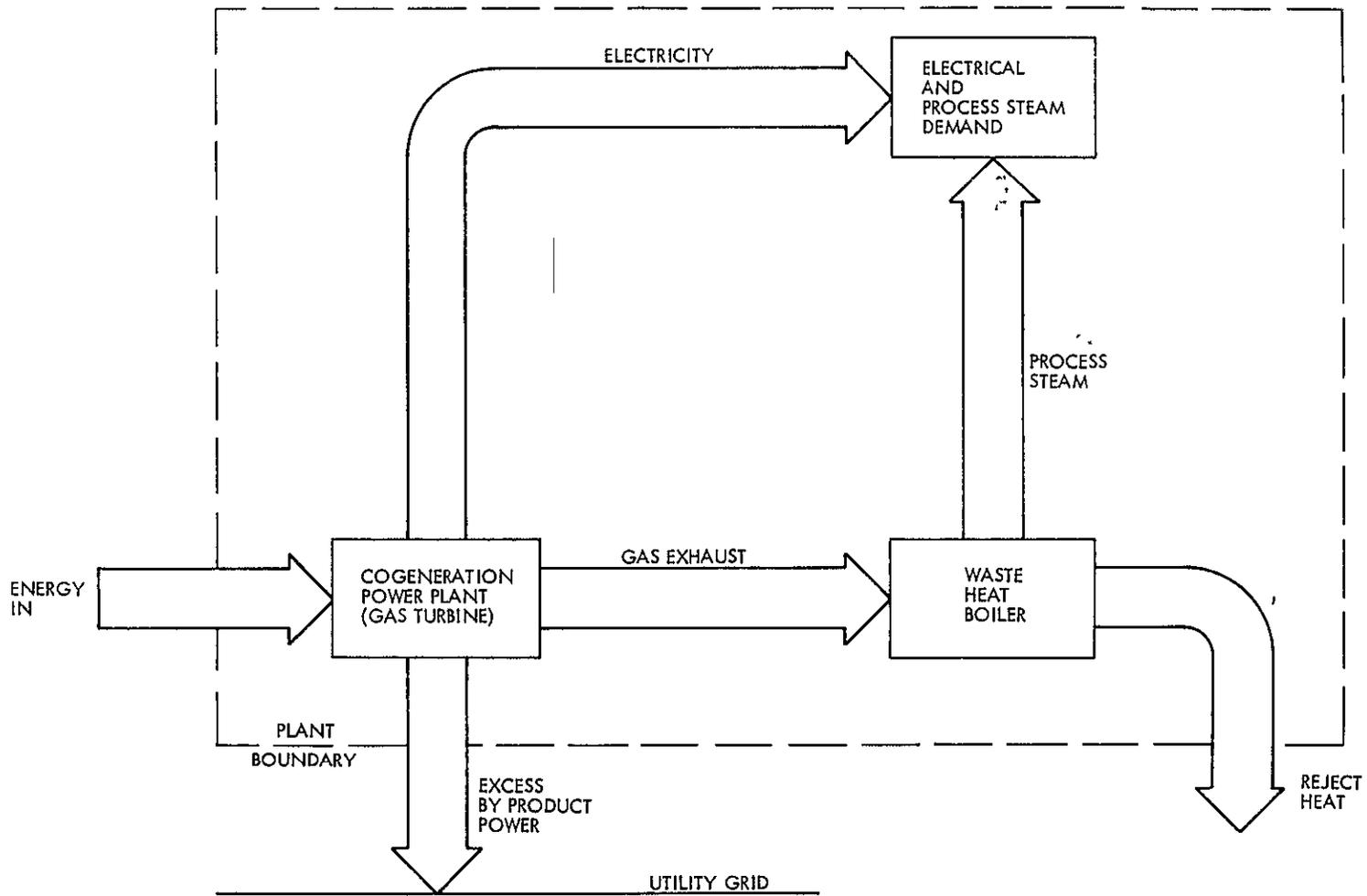


Figure 2-2. Cogeneration System (Topping Cycle-Gas Turbine) with Excess By-Product Energy and Utility Grid Tie-In. Applicable to (see Table 1-2) California Paperboard, Hunt-Wesson, Husky Oil, Kelco, and Simpson Paper (with steam turbine).

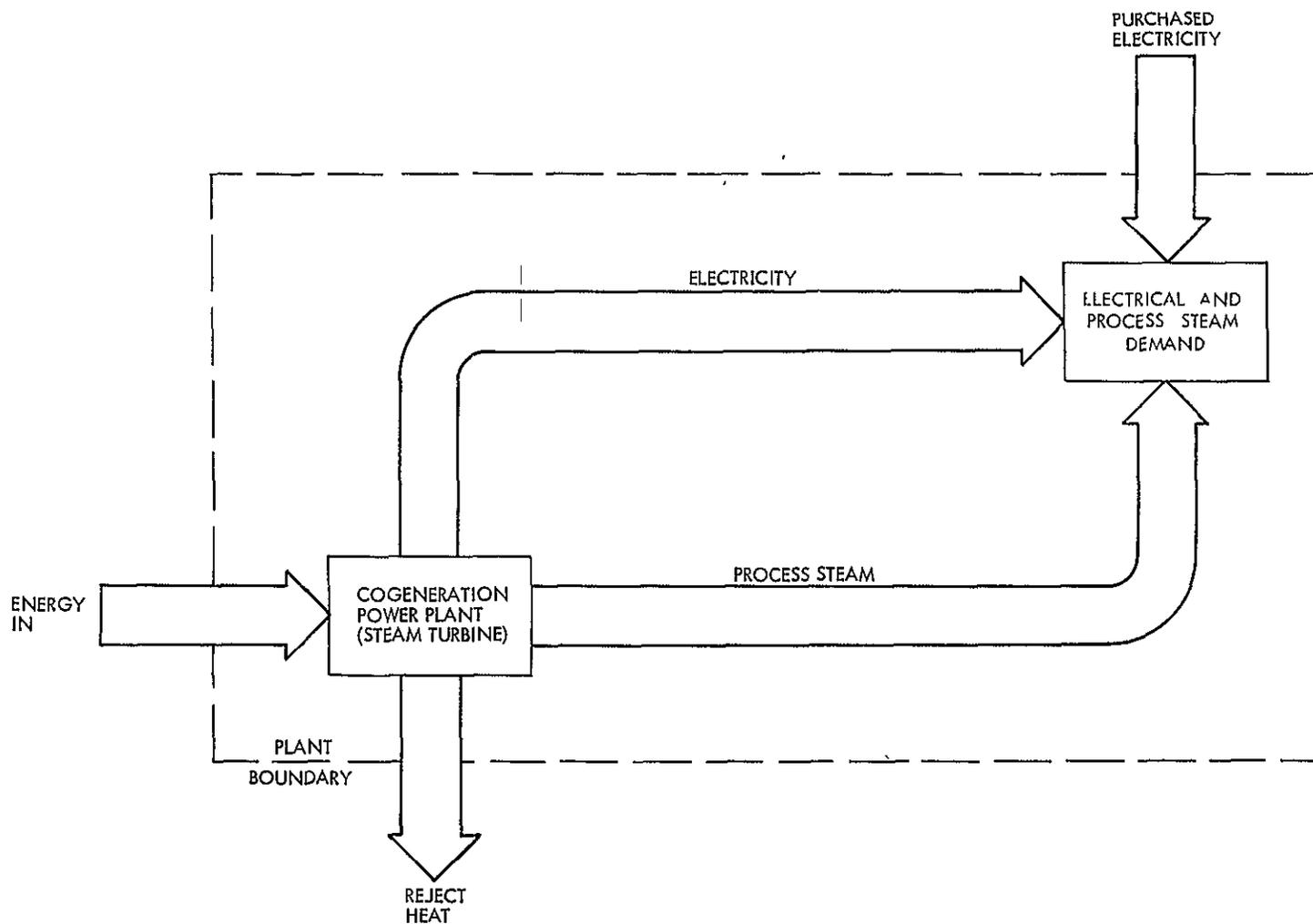


Figure 2-3. Cogeneration System (Topping Cycle-Steam Turbine) With Purchased Electricity. Applicable to (see Table 1-2) Kaiser Steel, Simpson Timber, Spreckels Sugar, Union Oil, and Exxon (with gas turbine).

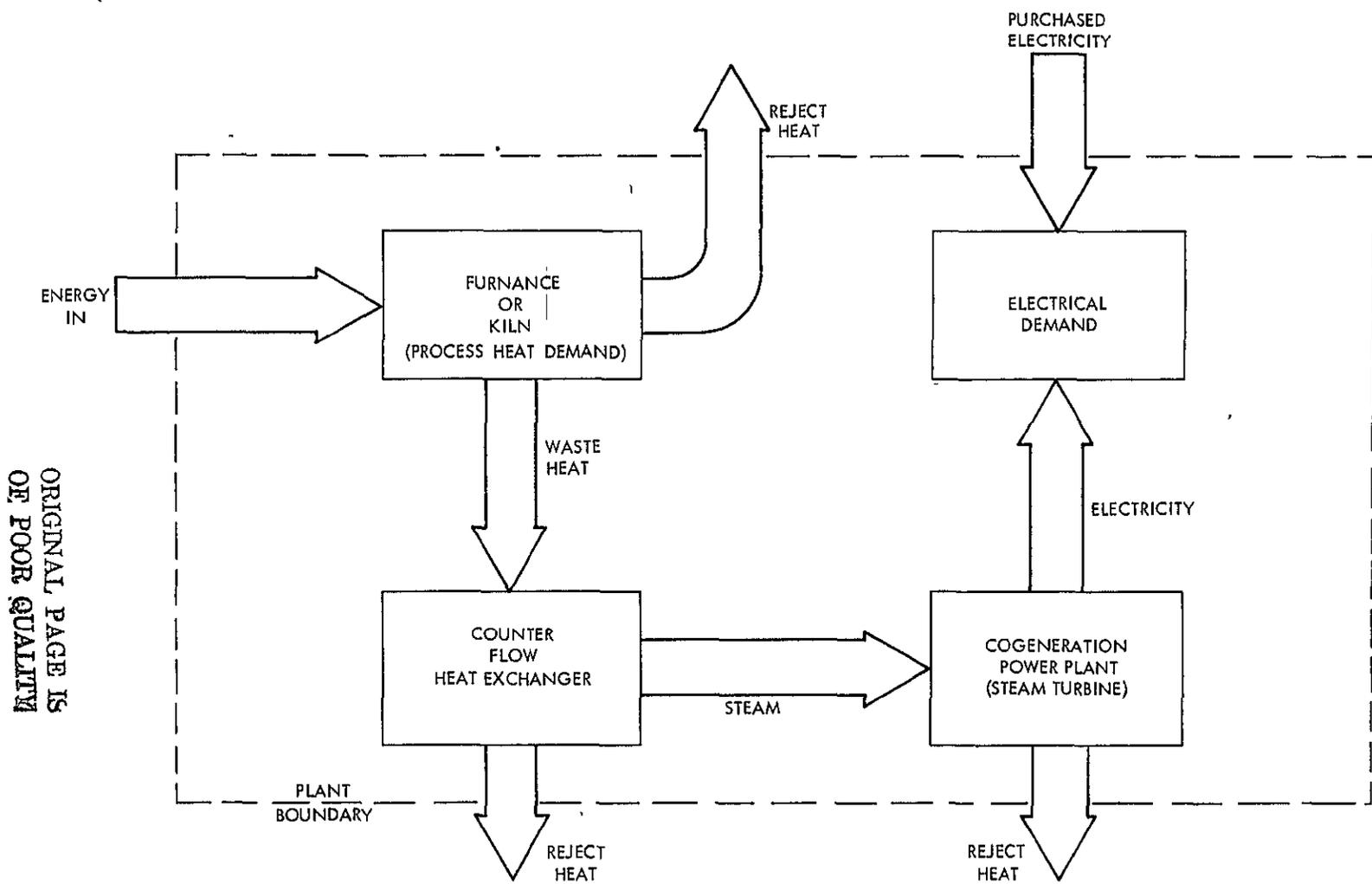


Figure 2-4. Cogeneration System (Bottoming Cycle-Steam Turbine) With Purchased Electricity. Applicable to (see Table 1-2) California Portland Cement and Owens-Illinois.

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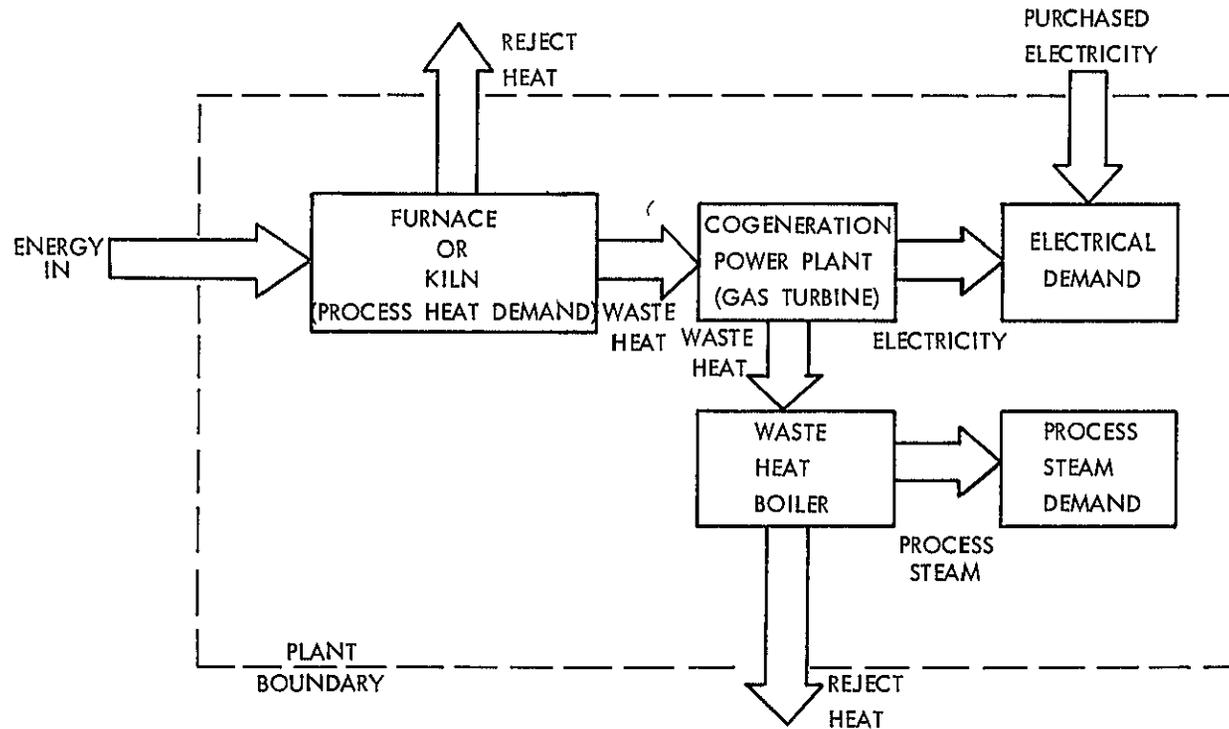


Figure 2-5. Cogeneration System (Bottoming Cycle-Gas Turbine) with Purchased Electricity. Applicable to (see Table 2-2) California Portland Cement and Owens-Illinois.

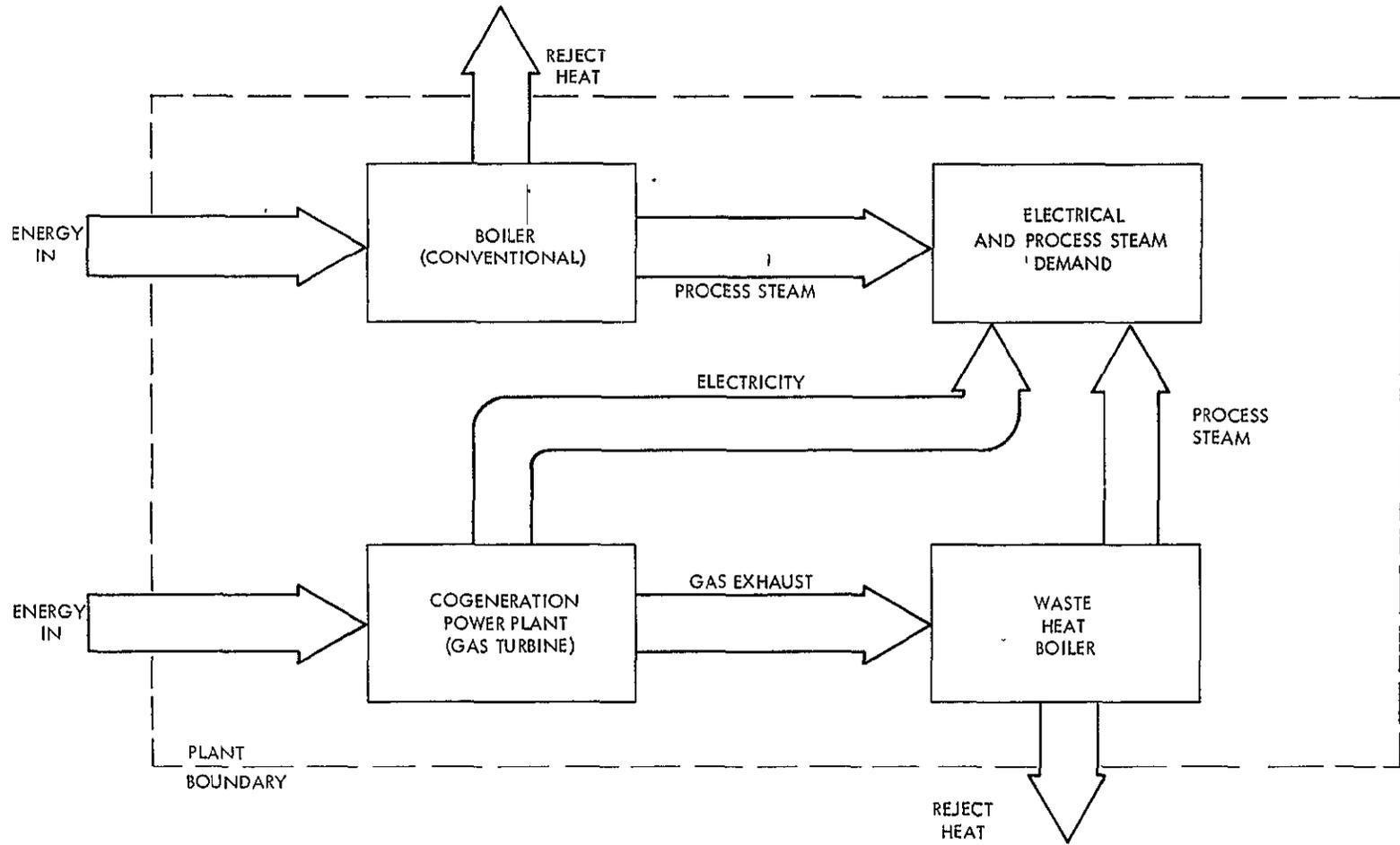


Figure 2-6. Cogeneration System (Topping Cycle-Gas Turbine) With Supplemental Boiler Firing. Applicable to (see Table 2-2 and text) California Paperboard and Kelco.

systems, however, are not optimum; they are included in this study to indicate the variety of engineering options available for cogenerating systems.

The calculated base system energy rates (Btu/hr) for each plant are given in Table 2-1. Results of the technical analysis are given in Table 2-2. The entries in both of these tables were obtained from the site reports (Appendix A) and from computations using the thermodynamic energy balance equations of Appendix B. A sample calculation is also given in Appendix B.

Using California Paperboard as an example, Table 2-1 is used as follows: The electrical demand, 4.0 MWe, is taken from site report. Using the steam tables, the enthalpy is determined based on the plant process steam pressure and temperature (also obtained from the site report). A steam demand of 85.3×10^6 Btu/hr was calculated knowing the steam flow and enthalpy. For given utility plant and existing plant boiler efficiencies, the electrical and steam energy required to meet the plant demands were determined to be 41×10^6 Btu/hr and 106×10^6 Btu/hr, respectively. The sum of these two values, 147×10^6 Btu/hr, is the total energy required for the base system to meet the plant electrical and steam demand.

Using California Paperboard to illustrate the use of Table 2-2, it can be seen (first line of table) that a gas turbine topping cycle was used to meet the 70,000 lb/hr steam demand of the plant. The gas turbine cogenerates 12.3 MWe* as calculated in Appendix B. The difference between the cogenerated power and the average demand of 4.0 MWe (from the site report) is 8.3 MWe. That is, 8.3 MWe of utility-generated power can be displaced by cogenerated power (assuming this excess by-product power can be delivered to the utility grid).

No electrical power is purchased in this example. The energy for the base system, 147×10^6 Btu/hr, was given in Table 2-1. The adjusted base energy, which includes the excess by-product energy, is 224×10^6 Btu/hr. The energy required to operate the cogenerating unit, which is sized to meet the plant steam demand, was computed using the equations in Appendix B and is equal to 156×10^6 Btu/hr. The calculated energy displaced by cogeneration, 77×10^6 Btu/hr, takes transmission losses and the overall utility power plant efficiency into consideration. Since there is neither supplemental boiler firing nor purchased electricity in this example, the energy required for the net cogeneration system is 156×10^6 Btu/hr. When compared to the adjusted base system energy requirement of 224×10^6 Btu/hr, this represents a net energy savings of 68×10^6 Btu/hr, or 30%.

*The fact that this estimate differs from the 10 MWe calculated in a detailed engineering study (see the California Paperboard site report) may be indicative of the accuracy and/or sensitivity of the analysis used in this study.

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Table 2-1. Base System Energy Requirements

| Plant | Energy Demand | | Process Steam Characteristics | | | | Base System Energy Requirements 10 ⁹ Btu/hr | | |
|----------------------------|--------------------------------------|---------------------------------|-------------------------------------|-------------------|-------------|---------------------|---|--------------------------------------|---|
| | Electrical Demand, D _E | Steam Demand, D _S | Mass Flow, 10 ³ lb/hr | Pressure, psig | Temp, °F | Enthalpy, Btu/lb | To Meet Electrical Demand, E _e | To Meet Steam Demand, E _s | To Meet Total Demand, E _{base} |
| | MWe | 10 ⁶ Btu/hr | | | | | | | |
| Calif Paperboard Corp. | 4.0 | 85.3 | 70 | 140 | 400 | 1219 | 41 | 106 | 147 |
| Calif. Portland Cement Co. | 15.8 | 0 | 0 | - | - | - | 162 | 596(*) | 758 |
| Exxon Co., U.S.A. | 35.0 | 207 | 150 | 600 | 750 | 1378 | 357 | 258 | 615 |
| Hunt-Wesson Foods, Inc. | Canning Season | 360 | 300 | 165 | Sat. | 1196 | 42 | 450 | 492 |
| | Off Season | 36 | 30 | 165 | Sat | 1196 | 21 | 45 | 66 |
| Husky Oil Co. | 0.6 | 1115 | 833 | 1300 | 750 | 1338 | 6.4 | 1448 | 1454 |
| Kaiser Steel Corp | 104.0 | 1138 | 950 | 175 | Sat. | 1198 | 1066 | 1062 | 2128 |
| Kelco Co. | 6.0 | 178 | 150 | 100 | Sat. | 1187 | 63 | 223 | 286 |
| Owens-Illinois, Inc | 11.7 | 0 | 0 | - | - | - | 120 | 420(*) | 540 |
| Simpson Paper Co. | 17.0 | 154 | 112 | 600 | 750 | 1378 | 174 | 193 | 367 |
| Simpson Timber Co. | 4.4 | 8.7 | 7.5 | 15 | Sat. | 1164 | 45 | 11 | 56 |
| Spreckels Sugar Co. | 5.0 | 178 | 139 | 400 | 600 | 1277 | 9 | 222 | 231 |
| Union Oil Co | 50.0 | 849 | 625 | 450 | 700 | 1358 | 514 | 1061 | 1575 |

(*) Portion of feedstock energy providing waste heat for cogeneration.

Table 2-2. Cogeneration System Energy Requirments

| Plant | Cogeneration System | | | Electrical Power, MWe | | | | Energy Requirements 10 ⁶ Btu/hr | | | | | | | Net Energy Savings Over Base System, ΔE _{NET} | |
|----------------------------|---------------------|-------------|--|-----------------------------|--|-------------------|-----------|---|---|---|--------------------------------------|--|-------------------------------------|---|--|-----|
| | Remarks | Gas Turbine | Condensing Steam Turbine Back Pressure Steam Turbine Condensing/Extraction Turbine | Cogenerated, E ₂ | Average Plant Demand, \bar{L}_{plnt} | Excess By-Product | Purchased | Base System E _{base} | Displaced by Cogeneration, E _{dis} | Adjusted Base System ** E _{base} | Cogeneration System, E _{CO} | Purchased Electricity, E _{AE} | Supplemental Steam, E _{AS} | Net Cogeneration System, E _{net} | 10 ⁶ | % |
| | | | | | | | | | | | | | | | Btu/hr | |
| California Paperboard Corp | T,S | λ | | 12.3 | 4.0 | 8.3 | 0 | 147 | 77 | 224 | 156 | 0 | 0 | 156 | 68 | 30 |
| | T,E | λ | | 4.0 | 4.0 | 0 | 0 | 147 | 0 | 147 | 50 | 0 | 51 | 101 | 46 | 31 |
| | T,S | | X | 1.8 | 4.0 | 0 | 2.2 | 147 | 0 | 147 | 115 | 22 | 0 | 137 | 10 | 7 |
| Calif. Portland Cement Co. | B | | X | 12.0 | 15.8 | 0 | 3.8 | 758 | 0 | 758 | 596* | 39 | 0 | 635 | 123 | 16 |
| | B | X | | 4.1 | 15.8 | 0 | 11.7 | 758 | 0 | 758 | 596* | 120 | 0 | 716 | 42 | 6 |
| Exxon Co., U.S.A | T,S | X | | 30.0 | 35.0 | 0 | 5.0 | 615 | 0 | 615 | 382 | 51 | 0 | 433 | 182 | 30 |
| Hunt-Wesson Foods, Inc | T,S,C | λ | | 50.6 | 4.2 | 46.4 | 0 | 492 | 476 | 968 | 640 | 0 | 0 | 640 | 328 | 34 |
| | T,S,O | | X | 0.8 | 2.1 | 0 | 1.3 | 66 | 0 | 66 | 46 | 13 | 0 | 59 | 7 | 11 |
| Husky Oil Co. | T,S | X | | 163.0 | 0.6 | 162.4 | 0 | 1454 | 1494 | 2948 | 2547 | 0 | 0 | 2574 | 374 | 13 |
| Kaiser Steel Corp | T,S | | X | 46.0 | 104.0 | 0 | 58.0 | 2128 | 0 | 2128 | 244 | 594 | 0 | 838 | 1290 | 61 |
| Kelco Co | T,S | X | | 25.9 | 6.0 | 19.9 | 0 | 286 | 182 | 468 | 327 | 0 | 0 | 327 | 141 | 30 |
| | T,E | X | | 6.0 | 6.0 | 0 | 0 | 286 | 0 | 286 | 78 | 0 | 159 | 237 | 49 | 17 |
| | T,S | | X | 1.9 | 6.0 | 0 | 4.1 | 286 | 0 | 286 | 228 | 44 | 0 | 272 | 14 | 5 |
| Owens-Illinois, Inc | B | | X | 4.9 | 11.7 | 0 | 6.8 | 540 | 0 | 540 | 420* | 70 | 0 | 490 | 50 | 9 |
| | B | λ | | 1.7 | 11.7 | 0 | 10.0 | 540 | 0 | 540 | 420* | 102 | 0 | 522 | 18 | 3 |
| Simpson Paper Co | T,S | | λ | 25.0 | 17.0 | 8.0 | 0 | 367 | 74 | 441 | 427 | 0 | 0 | 427 | 14 | 3 |
| Simpson Timber Co. | T,S | | X | 0.6 | 4.4 | 0 | 3.8 | 56 | 0 | 56 | 12 | 39 | 0 | 51 | 5 | 9 |
| Spreckels Sugar Co | T,S | | X | 4.2 | 5.0 | 0 | 0.8 | 231 | 0 | 231 | 222 | 9 | 0 | 231 | *** | *** |
| Union Oil Co | T,S | X | X | 40.0 | 50.0 | 0 | 10.0 | 1575 | 0 | 1575 | 1061 | 34 | 0 | 1095 | 480 | 30 |

* Portion of feedstock energy providing waste heat for cogeneration ** Adjusted for energy displaced by cogeneration. *** Already cogenerating

Key. T = Topping Cycle E = Meets electrical demand C = Canning season
 B = Bottoming cycle S = Meets steam demand O = Off season

As is evident in Table 2-1, with exception of Simpson Timber, the steam/electric demand ratio for topping cycle systems is greater than one. Thus, when large gas turbine cogenerating systems are used to meet the plant steam demand there will be large quantities of excess by-product electric power available. Correspondingly large savings in energy can therefore be realized in this situation if this excess power can then be sold or wheeled in order to displace power generated at a conventional utility power plant. For California Paperboard, Hunt-Wesson Foods, Husky Oil, and Kelco, the energy savings, under these conditions, is from 13% to 35%.

Less energy savings is achieved when a gas turbine cogeneration system generates only sufficient electricity to meet its on-site electrical demand and supplemental steam is generated by conventional boilers. In this case, the cogenerating units are smaller. For California Paperboard and Kelco, the energy savings under these conditions are 31% and 17%, respectively.

The cogenerating system for Hunt-Wesson Foods is unique when compared to the other 11 plants. The Hunt-Wesson refinery operates year-round but has low steam loads. The plant has a canning operation which has a high steam load (10 times that of the refinery), but operates only 5 months out of the year. Two concepts for cogeneration were considered.

First, a large gas turbine topping cycle system was sized to meet the higher steam loads during the canning season. Off-season, the gas turbine could serve as a utility peaking power plant, selling excess by-product power to the utility company. The major drawback is that, having no on-site application, large quantities of high temperature steam would be dumped. In this mode of operation, a 50.6 MWe unit would provide a 34% net energy savings during the canning season.

The second concept considered a small back pressure steam turbine topping cycle sized to meet the steam load of the refinery. Off-season, the 800 kWe unit would be adequate for the plant's needs. However, during the 5-month canning season, when the plant is running at maximum production, large amounts of additional electricity would need to be purchased in addition to firing conventional boilers. While this system is not practical during the canning season, it does serve to demonstrate an extreme case and uses a standard 800 kWe steam turbine system. Other concepts, using multiples of this standard steam turbine, might be developed for the plant.

Exxon and Union Oil each use on-site refinery fuel gas in their cogenerating systems. In each case the proposed cogenerating system is located adjacent to the plant and a gas turbine topping cycle provides electricity and steam to the refinery.

For Exxon, the cogenerating concept requires four existing boilers to be retired and provides 30 MWe of electricity to the plant. Thus, 5 MWe of electricity are purchased. In order to operate the gas turbines and still meet the refinery's steam load, 382×10^6 Btu/hr are required. The net cogeneration system requires 433×10^6 Btu/hr.

The base system total energy demand of 615×10^6 Btu/hr was only for purchased electricity. Based on these assumptions the net energy savings of the cogenerating system over the base system is 30%.

For Union Oil, two cogenerating systems were used: a gas turbine operating on available CO flue gas from the Catalytic Reforming Unit and, at the same time, a steam turbine utilizing stepped down steam from the Fluid Cat Cracker. Each system provides 20 MWe of power for a total of 40 MWe. The total energy requirement is 34×10^6 Btu/hr. The steam demand for the cogenerating system is the same as for the base system, 1061×10^6 Btu/hr. Comparing the total cogeneration energy requirement of 1095×10^6 Btu/hr with that of the base system, 1575×10^6 Btu/hr, the net energy savings is 30%.

The Spreckels Sugar plant in Manteca has been cogenerating for years with the system built into their process. Computations were made for the existing back pressure steam turbine topping cycle cogenerating system. A 4.2 MWe unit produces 139,000 lb/hr of cogenerated steam. To obtain these loads, 222×10^6 Btu/hr of energy is required. Since no other units were studied, there is no estimate of net energy savings.

In some instances there were seemingly inconsistent or conflicting data. In these cases, judgments were made in order to complete the analysis (see Appendix C). The sensitivity of the analysis to various input parameters has not been determined.

Finally, we observe that most of the plant studied create by-products which can be used as supplemental fuel, as illustrated below.

| Plant | By-Products Usable As Supplemental Fuel |
|--------------------------------|---|
| California Paperboard Corp. | -- |
| California Portland Cement Co. | High temperature waste heat |
| Exxon Co., U.S.A. | Refinery fuel gas |
| Hunt-Wesson Foods, Inc. | -- |
| Husky Oil Co. | Heavy crude oil |
| Kaiser Steel Corp. | CO blast furnace gas |
| Kelco Co. | Solid waste |
| Owens-Illinois, Inc. | High temperature waste heat |
| Simpson Paper Co. | Hog fuel |
| Simpson Timber Co. | Hog fuel and solid waste |
| Spreckels Sugar Co. | -- |
| Union Oil Co. | Refinery fuel gas |

B. ECONOMIC, ENVIRONMENTAL AND INSTITUTIONAL ISSUES

Table 2-3 highlights the economic, environmental, and institutional information contained in the site reports (Appendix A). No analyses have been performed with these data and all of the reported information reflects the perspective of the companies interviewed. We recognize that many of these issues are controversial and complex; however, for the purposes of this phase of the study only the industrial viewpoint has been reported.

Entries in the table correspond to the nontechnical information in the site reports. The economic considerations highlighted in the table are primarily those factors that are internal to the organization and reflect the company's approach to capital investments. Issues that are economic in nature, e.g., purchase price for steam, but are external to the organization and determined through negotiation are listed as institutional issues even though they may appear in the economic section of the site report. Other considerations that are institutional in nature are also included in the table.

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Table 2-3. Economic, Environmental and Institutional Issues

| Company | Issues | | |
|------------------------------------|--|--|---|
| | Economic | Environmental | Institutional |
| California Paperboard Corporation | Projects evaluated separately Accelerated depreciation Seven year depreciation life | Interpreting and meeting air quality regulations | Purchase price for steam Guaranteed long term agreement |
| California Portland Cement Company | Rate of return; 8 - 12% Market conditions important | Interpreting and meeting air quality regulations NO _x , SO ₂ and particulate requirements | Wheeling Standby power charges |
| Exxon Company, U.S.A. | Rate of return: risk dependent Market conditions important Decisions product/process oriented | Interpreting and meeting air quality regulations | Selling price for excess electricity |
| Hunt-Wesson Foods, Inc. | Return on investment: 25% Energy related projects have priority | Interpreting and meeting air quality regulations | Selling price for excess electricity |
| Husky Oil Co. | Accelerated depreciation | Interpreting and meeting air quality regulations | Guaranteed oil supply |
| Kaiser Steel Corporation | Short payback period | Meeting requirements Uncertainty about future requirements | Wheeling |
| Kelco Company | Payback period: 1-4 years | Interpreting and meeting air quality regulations | Purchase price for steam |

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Table 2-3. Economic, Environmental and Institutional Issues (Continuation 1)

| Company | Issues | | |
|----------------------------|---|--|--|
| | Economic | Environmental | Institutional |
| Owens-Illinois, Inc. | Decisions profit oriented Accelerated depreciation | Interpreting and meeting air quality requirements Uncertainty about future requirements | None |
| Simpson Paper Company | Return on investment: 22-25% Discounted cash flow method Accelerated depreciation | Interpreting and meeting air quality requirements Sulfur content of coal Uncertainty about future requirements | Selling price for excess electricity Standby power charges |
| Simpson Timber Company | Payback period: 4-5 years Priority to large rate of return and small payback period | Meeting requirements requires more energy | Wheeling Standby power charges |
| Spreckels Sugar Company | Return on investment: 20-25% | Sulfur content of fuel oil | None |
| Union Oil Company | Expected return on investment important: ~20% for cogen- eration projects | Interpreting and meeting air quality requirements | Rate structure |

SECTION III
INDUSTRIAL SURVEY

A. SITE SELECTION

The purpose of the site selection process was to identify 12 representative plants in the State of California which are not only in major energy-consuming industries but which also might implement cogeneration. The identification of those industries which generate significant quantities of process steam was originally considered to be an important step in this process because of the adaptability of steam generation to cogeneration utilizing a topping cycle. However, opportunities for cogeneration utilizing a bottoming cycle exist for industries having high temperature waste heat. In addition, the project sponsor specifically requested the following general industry categories be included: petroleum refineries, cement, wood products, and food products. Furthermore, previous studies indicated that the inorganic chemicals, blast furnaces, and glassware industries are high thermal energy users and have high temperature processes. The Standard Industrial Classification (SIC) code was the means by which the data were classified. Thus, all the industries considered either produced steam or had processes with high temperature waste heat.

Selection criteria developed during the course of this study evolved through discussions with California Energy Commission Staff and through meetings with other organizations involved with cogeneration applications. A scoring system was devised whereby the criteria were rated by project personnel and the project sponsor according to their relative importance. The final site selection criteria are:

- (1) Industry's rank in California for thermal energy use - from California Solar Thermal Applications Plan report.
- (2) Size of plant based on energy consumed - from initial telephone contact.
- (3) Informativeness of the respondent - from initial telephone contact.
- (4) Utility district - based on a balanced statewide representation.
- (5) Air pollution control district - based on a balanced statewide representation.
- (6) Cogeneration potential - from reported cogeneration activity and capacity.

To begin the actual selection, the index Marketing Economics Key Plants was consulted for names and addresses of those plants in California for the industries discussed above. Project team members made telephone contact with plant engineers and/or managers in 99 representative plants throughout the state. Information concerning the plant's energy consumption, steam and heat requirements, and general operating information was obtained.

In general, the identification of industries generating significant quantities of process steam was not as important to the selection of candidates as had been originally thought. A broader category of potential candidates for cogeneration was evaluated by using thermal energy use as a guide rather than significant quantities of process steam. However, from the industries considered for this study, those producing the most process steam are: petroleum refineries, industrial inorganic chemicals, blast furnaces, and pulp mills.

Of the 99 plants contacted, 54 were eliminated from consideration as not being suitable for cogeneration. In many instances, the plants contacted were small and not interested in implementing cogeneration. In other cases, the SIC code was too general and served only as a catch-all for a variety of plants with very small steam requirements or with no utilizable waste heat. The remaining 45 plants were listed by industry and then ranked according to study selection criteria. The pertinent data for each plant as applied to the selection criteria were then compared and contrasted. Reducing the number of plants to 12 required several iterations plus interactions with the project sponsor.

B. SURVEY PROCESS

Discussions were held with representatives of the Southern California Edison Company and with Resource Planning Associates personnel concerning the questionnaires used in their respective cogeneration surveys. Based on this information, and in anticipation of the Phase II follow-on study, a questionnaire was developed. The information to be obtained was divided into four broad areas: technical and background information pertinent to the plant and its operation; economic data to provide insight into the investment decision process; environmental regulations as they related to the plant and future investment plans; and institutional issues and their effect on plant operations. All the information was to be site-specific to the plants visited.

An interview check list was then developed to serve as a guide that the interview team could follow during the course of the interview. A data summary format was also developed to serve as a guide for transcribing rough interview notes into a standard site report. The interview team included a system design engineer and a systems analyst and was responsible for acquiring the desired information. A team leader, assigned for each site, had responsibility for:

- (1) Making arrangements for the site visit.
- (2) Directing the discussion during the interview.

- (3) Performing follow-up functions.
- (4) Writing up the site report.

A major problem encountered was the wide variance in the quality of data obtained. While all of the companies that participated were very interested in the outcome of the study, some were able to disclose more information than others, according to company policy. Regrettably, in several instances appropriate company officials were not able to attend the interviews due to last minute changes in plans. Where needed, follow-up phone calls and return visits were made in order to fill in at least some of the missing information.

The survey response was favorable. Almost all of the companies that were called agreed to participate in this study. Every company that was interviewed gave the interview team a plant tour and was willing to share its interests and concerns with respect to energy conservation, environmental regulations, and, more specifically, cogeneration implementation for its plant.

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APPENDIX A-1

COGENERATION SITE REPORT
PAPERBOARD PRODUCTS INDUSTRY (RECYCLED PAPER)

CALIFORNIA PAPERBOARD CORPORATION
SANTA CLARA

Participants

California Paperboard

J. Sandin
J. Studenicka

Jet Propulsion Laboratory

V. C. Moretti
M. L. Slonski

City of Santa Clara

B. R. Flynn

Slinger and Associates, Inc.

G. A. Needham

Utility: City of Santa Clara
Air Basin: San Francisco Bay Area
APCD: Bay Area
AQMA: San Francisco

Address: California Paperboard Corp.
525 Mathew St.
Santa Clara, CA 95050
(408) 244-7400

This site report is based on notes taken by survey team members during visits to the plant, telephone conversations with plant personnel, and various reports furnished by the company. The report has been reviewed and approved by the company. The opinions, attitudes, and conclusions expressed in the report are those of the company and not necessarily those of the Jet Propulsion Laboratory.

I. GENERAL INFORMATION

California Paperboard Corporation, a subsidiary of Newark Boxboard Company, Newark, New Jersey, operates a relatively small paperboard mill. All of its raw material is wastepaper from the solid waste stream. The plant has two paper machines and produces a total of 200 tons/day, which is converted into a variety of paper end-use products (500-600 tons/day is considered a large recycled paperboard plant). The plant is located on five acres in the City of Santa Clara and employs 110 people, including salaried employees.

About 30 paper mills in California produce paper products of varying quality. The paperboard industry is an advanced industry for technology and process improvements, and California Paperboard is a leader in innovation with respect to developing resources and energy conservation.

There are two trade organizations, the Technical Association of the Pulp and Paper Industry (TAPPI) and the Boxboard Research and Development Association (BRDA). The latter has been involved in energy research but not with respect to cogeneration.

The City of Santa Clara has its own Electric Department which currently purchases 200 MWe of raw power from the Bureau of Reclamation and PG&E, and uses its own distribution and transmission system. The City would like to become self-sufficient as a utility and is conducting studies in the areas of geothermal energy (88 MWe potential), solar energy, and cogeneration as new power sources, primarily to reduce their reliance on PG&E power.

—II. PLANT PROCESSING OPERATION

Waste paper is reduced to paper pulp by a mechanical and steam pulping machine using 10,000 lb/hr of steam at 100 psi and 350°F. The pulp stock is pumped and cleaned, then put through the refining process where the fibers are cut to the specified length for the end product. The refining process uses high horsepower (600-800 hp) motors. After the pulp has been refined, it is ready to be fed to the paper machine which presses out excess water and sends the wet sheet through steam heated dryers. The dryers use 55,000 lb/hr of steam from 100 psi at 350°F down to 40 psi at 275°F. The paper is wound on spools, then re-wound and cut to the finished size specifications.

The steam to the dryers comprises the greatest use of thermal energy in the plant. These steam-heated dryers are used to evaporate moisture from a continuous web of paper passing over them. Hot condensate from the dryers is returned to the boiler plant. The dryers exhaust some heat at less than 200°F in a vapor state which goes into the atmosphere.

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III. COGENERATION POTENTIAL

Slinger and Associates, Inc., completed a cogeneration feasibility study for the California Paperboard plant in August 1977. The final report outlines two alternatives for cogeneration that will match the steam load requirements. Alternative 1 utilizes a high pressure boiler and a steam turbine system to generate 2 MWe of electricity and 140 psig, 400°F superheated exhaust steam to be used in the process, as shown in Figure 1. The steam supply to the turbine would be 70,000 lb/hr, 650 psig at 650°. This alternative would cost about \$870,000 and includes a reconditioned turbine generator presently owned by California Paperboard.

Alternative 2 utilizes four gas turbine generating units that would generate a total of 10 MWe of electricity. The exhaust would go to four low pressure waste heat boilers which would produce 70,000 lb/hr of steam at 140 psig, 400°F to be used in the process. This concept, depicted in Figure 2, would cost about \$3,220,000.

Alternative 2 appears to be the most attractive from the City's point of view. If this alternative is approved by the Santa Clara City Council, it will be two or three years before the project is completed and operational.

IV. ECONOMIC CONSIDERATIONS

California Paperboard Corp. has an informal capital investment evaluation program. Capital expenditures are normally approved by the owners of the parent company, all projects being evaluated on an individual basis. The parent company has purchased failing companies and has turned them into profitable operations. To date, they have purchased seven paper recycling mills that have been upgraded and made into profitable operations; in many instances, equipment has been inefficient and antiquated. California Paperboard was purchased in 1974 and more than \$2 million for line equipment has been spent to update and improve the plant operation. The company is very concerned about ecology and processes only recycled paper; energy conservation projects have a very high priority for them.

For tax purposes, the company uses the double declining balance (DDB) depreciation method going to a straight line (SL) depreciation method after three or four years. The depreciation life used for their equipment is seven years. For most investments, the company expects a conservative payback period of three or four years.

The cost of natural gas comprises about 13 percent of the total cost of production, and the cost of electricity about 7 percent. The total cost of steam is about 10 percent higher than the cost of the fuel, taking into account operations and maintenance costs. The project proposed for California Paperboard Corporation would not be an attractive investment from the company's point of view, since the economic analysis would be based on an attempt to offset the inexpensive rate the company pays for electricity. However, the supplying utility in

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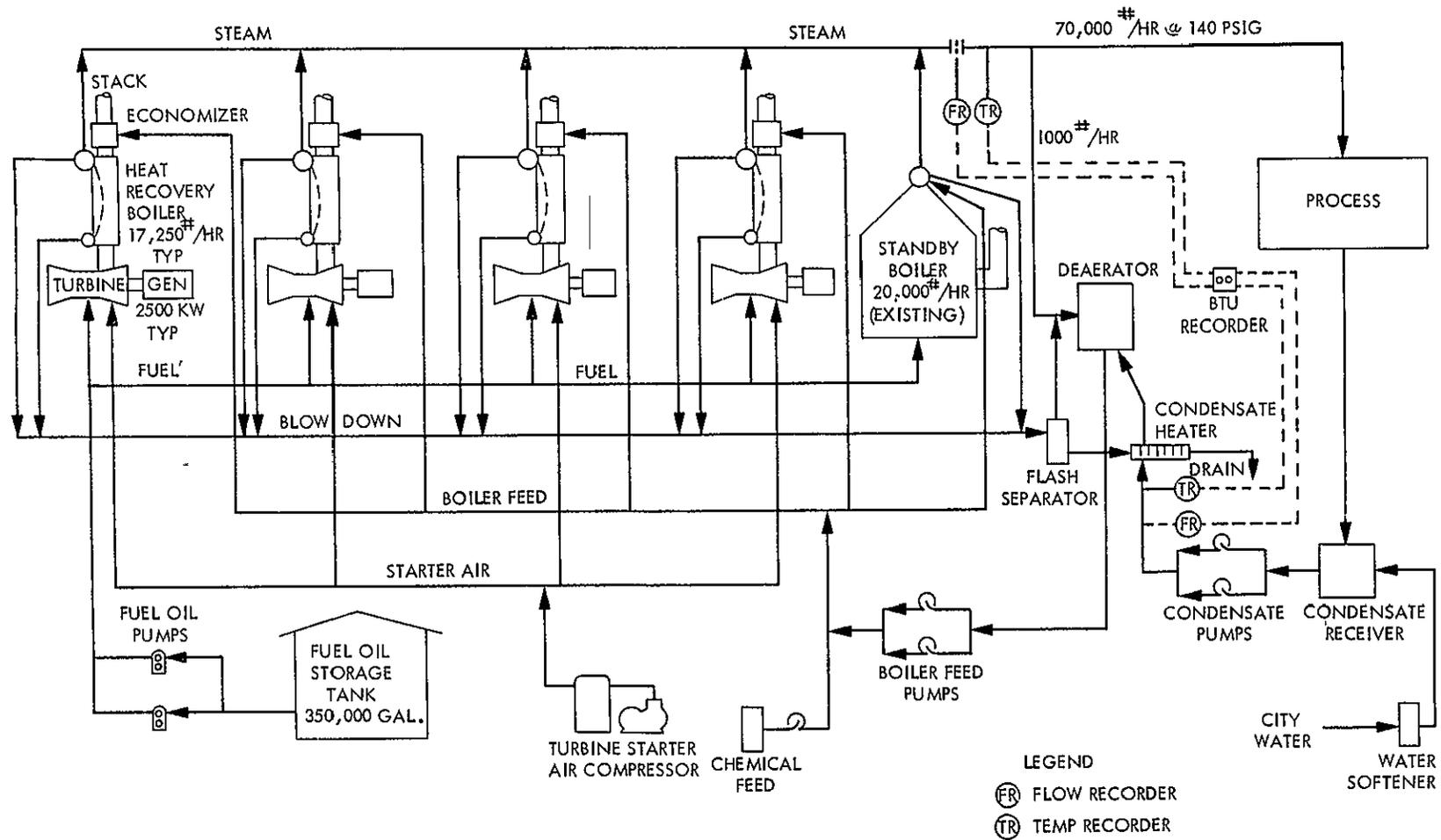


Figure 2. Cogeneration Flow Diagram: Alternative No. 2, Gas Turbine System

this case is the City of Santa Clara and the project becomes economically viable because the evaluation of the cogeneration project is based on offsetting the high cost power supplied by PG&E.

The City of Santa Clara, as a municipal utility, has the advantage of other economic factors that favor the installation of cogeneration. The City requires an 8 percent rate of return for capital investment projects. As a municipal government they pay no taxes and can use existing funds to finance cogeneration projects on an on-going basis. For the first cogeneration project the City can finance up to \$2 million with cash; the rest will come from the users who will benefit. Future cogeneration projects will be financed by municipal revenue bonds.

The primary concerns of California Paperboard are (1) the price of the steam they will purchase from the City and (2) the fact that any agreement with the utility requires a guarantee that California Paperboard will stay in business for a specified period of time. With respect to the first concern, the City expects to be able to reduce the steam cost to California Paperboard by 5-10 percent. With respect to the second concern, the recommendations of Slinger and Associates, Inc. include no capital investment on the part of California Paperboard and an economic evaluation based on a short life expectancy of the equipment (10 years); thus an attempt was made to share the risk of the project between the two parties and for a minimum time period.

The City of Santa Clara has a contract with the Bureau of Reclamation for hydroelectric power. PG&E is the wheeling agent for the power and provides additional supply when the Bureau cannot meet the City's requirements. The City pays the Bureau 5 mills/kWh and PG&E 28-30 mills/kWh. At the present time there is a dispute concerning the contractual arrangements with the Bureau and PG&E. In particular, it is not known exactly how much power is supplied by the Bureau and how much is supplied by PG&E. The dispute has been taken to court and a decision is pending. Regardless of the outcome of the court action, it is clear that PG&E will be supplying more of the City's power in the future. It is the high cost of that power which has provided the incentive for the City to seek alternate sources of electricity. Within the next 5-10 years the City plans to have 50 MWe of their own cogenerated power on line.

The Slinger cogeneration report presents an economic analysis for the two cogeneration alternatives considered; both concepts require the cogeneration plant to be owned by the City and located at California Paperboard. A 10-year life is assumed for the equipment. The following three tables are taken from the report.

ANNUAL OPERATING COSTS

1977 Dollars
Thousands of Dollars

Investment and annual cost to supply a total of 70,000 pounds per hour of steam plus 10 MWe of electric power. Operating factor: 91.3%

| | Base Case All Power Purchased | Alternative No. 1 2 MW Topping Turbine | Alternative No. 2 10 MW Combustion Turbine |
|-------------------------|-------------------------------------|---|---|
| Investment | | 870 | 3,220 |
| Annual Cost | | | |
| Fuel Oil - Steam | 1,806 | 1,806 | 1,806 |
| Fuel Oil - Power | -0- | 196 | 1,125 |
| Purchased Power | 2,280 ^{1*} | 1,885 ^{2*} | 155 ^{3*} |
| Operation & Maintenance | 70 | 70 | 150 |
| Insurance ^{4*} | 1 | 3 | 10 |
| Total Annual Cost | 4,157 | 3,930 | 3,246 |

COST ESTIMATES

| Description | Alternative No. 1 | Alternative No. 2 |
|---|-------------------|-------------------|
| Building & Structural | \$ 21,000 | \$ 33,000 |
| Power System Electrical | 90,000 | 330,000 |
| Equipment & Building Electrical Wiring | 26,000 | 26,000 |
| Mechanical Systems - Includ- ing boilers, turbine gener- ators, auxiliaries, and associated piping systems | 630,000 | 2,561,000 |
| Subtotal | \$767,000 | \$2,950,000 |
| Contingency | 38,000 (5%) | 90,000 (3%) |
| Engineering | 65,000 | 180,000 |
| TOTAL | \$870,000 | \$3,220,000 |

1* 80 GWh at 2.85¢ per kWh

2* 64 GWh at 2.85¢ per kWh plus demand charge for 1,000 kW average monthly demand at \$2.85 at per kWd - month

3* Demand charge for 5,000 kW average monthly demand at \$2.85 per kWd-month

4* 0.3% of investment

COGENERATION ALTERNATIVES

DISCOUNTED CASH FLOW STUDY

All quantities are in thousands of dollars unless otherwise indicated.

| | Base Case - Purchase All Power, Use Existing Boiler | Alt. 1 2 MW Topping Turbine | Alt. 2 10 MW Combustion Turbine |
|--|---|--------------------------------------|--|
| Investment | | 870 | 3,220 |
| Annual cost | 4,157 | 3,930 | 3,246 |
| Annual cost reduction | | 227 | 911 |
| Ratio: Cost reduction/investment | | 26% | 28% |
| Present worth of 10 years of savings at 8% interest | | 1,523 | 6,113 |
| Ratio: Present worth/investment | | 1.75 | 1.90 |
| Payoff period in years at 8% interest rate | | 4.76 | 4.32 |
| Rate-of-return for 10-year payoff period — | | 22.7% | 25.3% |

V. ENVIRONMENTAL ISSUES

The most critical factor affecting the cogeneration project is the interpretation of the New Source Review Rules. A net reduction in pollutants for the entire air basin can be argued based on a credit allowance for the reduction in power generated by PG&E that is offset by the power cogenerated at California Paperboard. There will, however, be an increase in pollutants in the local area due to the increased fuel required to cogenerate. Since the current New Source Review Rules do not allow the project to take credit for a reduction in pollution by less efficient generators operated within the same air basin, there is uncertainty at the present time as to how the project will be evaluated by the APCD and whether or not it will be approved. The City plans to file a negative declaration under the California Environmental Quality Act based upon this offsetting effect as far as air pollution for the whole air basin is concerned. Air pollution is the only significant environmental effect of the project. A negative declaration will measurably reduce the lead time before design and construction can get underway.

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VI. INSTITUTIONAL ISSUES

As a municipal utility, the City of Santa Clara is not under the jurisdiction of the PUC and its rate structure is kept as simple as possible. California Paperboard and the City of Santa Clara agree on the concepts, ownership, and installation of a cogeneration plant. Both the City and California Paperboard are conservation-oriented, and an agreement is expected to be reached soon.

The City has a concern with respect to the priorities assigned for natural gas. Currently, natural gas used for the generation of electricity has a priority of P5. For industrial processes like California Paperboard, the priority is P4. With the installation of a cogeneration plant at California Paperboard but owned by the utility, the question arises as to which priority will be given to the natural gas required for the plant. The City would like to have the amount of gas currently used by California Paperboard maintained at the P4 priority rating with only the additional requirements on a P5 priority basis. The resolution of this concern rests with the PUC and PG&E, which may have an impact on the implementation of the cogeneration project. Of course, a higher priority rating, given on the basis that cogeneration provides the most efficient use of fuels, would be a very positive incentive which would help assure the economic viability of such a project.

VII. TECHNICAL DATA

A. PROCESSING EQUIPMENT

The operational characteristics of the two boilers used in the process are shown in the table below.

| Type | Size lb/hr | Age, yr | Type of Energy Used | Duty Cycle S = Steady V = Variable | Repair Frequency | Location (clustered vs scattered) | Future Plans |
|--------------------|---------------|------------|--|--|---------------------|--|------------------------------|
| Package Boilers | | | | | | | |
| 1 | 36,000 | 35 | } Natural gas No. 2 oil as backup | } S | } 1-2 days/ yr | } C | None unless cogenerate |
| 2 | 60,000 | 1-1/2 | | | | | |

There are no future process modifications anticipated which would alter the plants steam requirements. The large boiler installed 1-1/2 years ago cost about \$120,000. Steam cost is estimated at \$2/1000 lb with both boilers needed to meet the steam requirements.

B. PROCESS ENERGY PROFILE

1. Electrical Demand

The California Paperboard plant has an average demand of 4 MW and a peak demand of 4.4 MW. The plant operates 24 hours a day year round except for four holiday shutdown periods. The power load is constant with a capacity factor of 90-95%, except for equipment failures and the four shutdown periods. A peak occurs in the load during startups. The two refiners together require 1.0 MW; there are many pumps and other electrical equipment which account for the rest of the demand.

Purchased electricity costs about \$55,000/mo, with a 79% power factor. In May 1977, they used approximately 2.5×10^6 kWh at 2.1¢ per kWh. In August 1977 this was 2.22¢ per kWh, more than a 40% increase over their price of 1.54¢ per kWh less than a year ago.

2. Steam Load

The steam load of the plant is between 60,000 and 70,000 lb/hr with variation occurring only if there is an equipment breakdown. On an annual basis the steam load is constant with the exception of four holiday shutdown periods.

The boiler characteristics are enumerated in the following table:

| Boiler | Capacity, lb/hr | Temp, °F | Pressure, psig | Fuel | Efficiency |
|--------|-----------------|----------|----------------|-----------------------------------|------------|
| 1 | 36,000 | 350 | 100 | Natural gas (No. 2 oil backup) | 80% |
| 2 | 60,000 | 350 | 100 | Natural gas (No. 2 oil backup) | 80% |

3. Fuel Use

The California Paperboard plant uses natural gas when it is available, and burns #2 fuel oil when the gas is curtailed; they pay about \$1.4 million a year for gas. The natural gas is supplied on a priority P4 curtailment schedule. In the current year they have experienced 12 days of curtailment during the winter months.

| Type Fuel | Quantity | Present Cost |
|---------------------|--------------------|--------------|
| Natural gas | 60,000 cu ft/hr | 2.14/MBtu |
| Distillate fuel oil | 56,000 gal storage | 2.75/MBtu |

VIII. KEY PROBLEM AREAS

- (1) Meeting offset provisions of the New Source Review Rules established by the Air Resources Board.
- (2) Acceptable price for steam purchased by California Paperboard.
- (3) Risk associated with a long term agreement with the City of Santa Clara.
- (4) Priority and allocation of natural gas.

APPENDIX A-2

COGENERATION SITE REPORT
CEMENT MANUFACTURING INDUSTRY

CALIFORNIA PORTLAND CEMENT COMPANY
MOJAVE PLANT

Participants

California Portland Cement

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R. G. Patterson
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Jet Propulsion Laboratory

H. S. Davis
R. M. Gurfield

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Air Basin: Southeast Desert
APCD: Kern County
AQMA: None
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(213) 680-2316

This site report is based on notes taken by survey team members during visits to the plant, telephone conversations with plant personnel, and various reports furnished by the company. The report has been reviewed and approved by the company. The opinions, attitudes, and conclusions expressed in the report are those of the company and not necessarily those of the Jet Propulsion Laboratory.

I. GENERAL INFORMATION

There are 164 cement plants in the United States, 12 of which are in California. The California plants belong to eight separate corporate owners. Production quantities for all cement plants are published by the Bureau of Mines, with the figures being about 10 percent on the high side. Production for California is about 10 million tons per year. The California Portland Cement Mojave plant produces 1.11 million tons per year, more than 10 percent of the state's total. The Mojave plant is the second largest in the state; the Kaiser Permanente plant is the largest. The Mojave plant has five kilns located on 460 acres of land. There are 260 employees who operate the plant on a continuous year-round basis.

The most innovative leader in the industry is the Huron Cement Company in Alpena, Michigan. This plant, the largest in the United States, has 29 kilns and an output capacity of 2.9 million tons per year. An article in the August 1976 issue of Rock Products magazine describes this plant and its plans to install two waste heat boilers on two of their new kilns. These waste heat boilers are now in operation. In California, both Kaiser and California Portland Cement are innovative leaders.

The trade organization for this industry, the Portland Cement Association, is performing continuous research in the area of energy conservation. However, it has not taken an industry-wide position on cogeneration or on air pollution. Rather, it lobbies or works with local legislatures and governments to represent the impact on the local cement industry as a result of particular programs.

II. PLANT PROCESSING OPERATIONAL

Cement is composed of raw materials such as limestone, shale, iron ore, and alumina. These materials are processed to form an intermediate product called clinker. The clinker is mixed with imported gypsum (4-5% by weight) and the final product is called portland cement. To manufacture clinker, the raw materials are crushed, mixed, blended, ground, and fired. The firing process takes place in very long kilns and formulates the clinker under tremendous heat (2800-3000°F). Prior to the kiln operation, the plant is similar to a crusher plant with electricity being used for electric motors, cranes, and power-driven devices. The kiln is heated by the burning of fuel. The Mojave plant uses company-owned coal (from their Utah mines) and bunker C fuel (residual fuel oil No. 6), purchased and stored in large tanks. The fuel oil is used only as a backup to the more economical coal, which has a 25-year supply life. The final product, portland cement, is mainly sold in bulk quantities. (The ready-mix industry is the major customer, purchasing 85% of the gross.) Recently, California Portland Cement has been looking at means to save the waste heat from their kilns. Waste heat temperatures range from 1000°F to 1100°F.

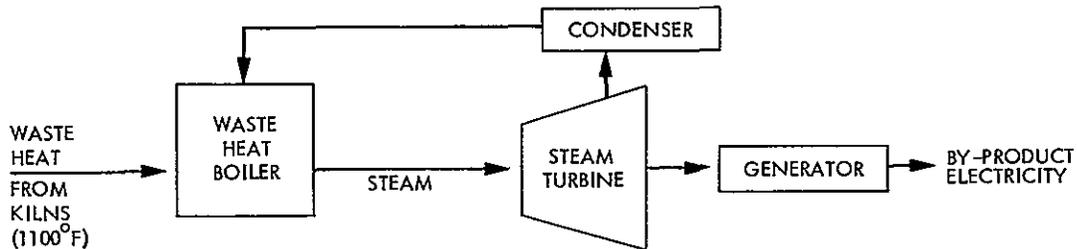
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III. COGENERATION POTENTIAL

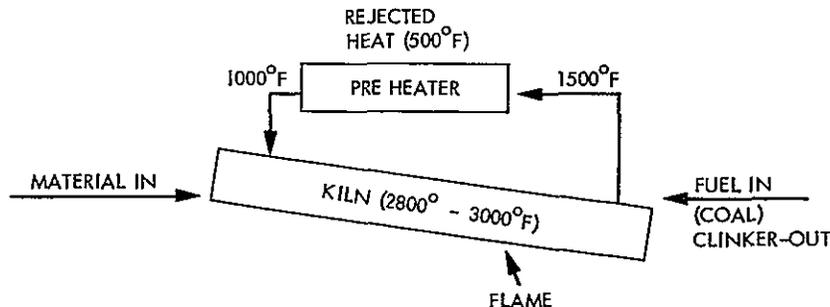
California Portland Cement has an abundant supply of waste heat from their kilns. In its modernization plan for the Mojave plant, the company is considering four cogeneration options:

- (1) Cogenerate by using waste heat from the kilns which will provide 60-70% of the plant's electrical needs. Edison must supply the remainder, plus backup, when a kiln is down. The existing plant could provide 12 MWe under this option.
- (2) Add a supplemental coal-fired boiler to option 1 to meet 100% of the Mojave plant needs. In case of a turbine failure, backup will be required from Edison.
- (3) Add a larger supplemental boiler to provide power for both the Mojave and Colton plants (Colton requires 16 MWe); Edison would have to provide backup power and an attractive wheeling rate.
- (4) Add a larger boiler to provide surplus power to the Edison system, up to 100 MWe.

The diagram for option 1 is as follows:



In addition to the four options for cogeneration, California Portland Cement has the option to reuse the captured waste heat from the kiln process and recycle it to the kiln. The utilization of a preheater system as shown in the following diagram would eliminate the cogeneration concept.



The incentives for California Portland Cement to cogenerate are lower fuel costs (they use their own coal), lower electrical energy charge per kilowatt hour for the electricity used, and an acceptable rate of return on investment. They can generate waste heat power at 0.6¢/kWh and with supplemental firing at 1.6¢/kWh. Furthermore, they would not have to pay peak demand charge on their own power.

IV. ECONOMIC CONSIDERATIONS

The California Portland Cement company does not require a specific percentage return nor do they have a formalized method for evaluating capital investment projects. Rather, they tend to favor projects which will yield a return in the range from 8-12% after taxes, but other factors such as current and predicted market conditions may have a significant impact on the final decision. Ancillary investments are not necessarily evaluated differently from product-related investments.

Each year the company evaluates each plant with respect to major equipment replacements. In some cases, equipment with useful life remaining may be phased out prematurely, especially if the replacement will help keep costs down or improve energy consumption requirements. They do not specify cost limits before projects are evaluated. Their primary concern is to remain competitive.

The expansion plans for the Mojave plant have not been completed, but the capital investment will probably be in the range of \$40-50 million, which does not include the cogeneration scheme. Financing is usually through bank term loans, depending on the amount. A \$30 million investment in the Arizona plant was financed on a 7-year term loan obtained from a bank. Longer term loans may be necessary for much larger amounts.

The company uses a straight line depreciation for both book and tax purposes.

V. ENVIRONMENTAL ISSUES

The Mojave plant presently has a pollution problem with NO_x; SO₂ and particulates will be of added concern with respect to a cogeneration facility. The regulation of emissions will have an effect on the decision to modernize and expand the plant as well as on cogeneration plans.

The most efficient flame temperature for the kilns, from a fuel consumption point of view, is about 2800°F. However, at that temperature, NO_x is produced. A temperature reduction to below 2200°F eliminates the NO_x but it is not possible to make clinker at this temperature.

SO₂ is not a problem in the production of cement because most of the sulfur will combine in the clinker. However, with supplemental firing for cogeneration, SO₂ will go up the stacks. This situation will require the use of scrubbers, which in turn will increase the fuel consumption in the power plant. These consequences may make supplemental firing an uneconomical proposition.

Finally, with respect to particulates, each kiln presently has a rate of emissions of approximately 30 lb/hr. Existing regulations permit an emission rate of 40 lb/hr, but under the New Sources Review regulations for pollution control, only 15 lb/hr or 150 lb/day will be permitted. Therefore, with respect to any new equipment, California Portland Cement would have to add bag houses in order to meet the lower particulate emissions standard.

VI. INSTITUTIONAL ISSUES

The technology for cogeneration is not a problem to California Portland Cement, nor does it matter to them whether they or Southern California Edison run the power plant. The biggest uncertainty is the reaction of the Public Utilities Commission should California Portland Cement request to wheel electric power from the Mojave plant. Another concern is the Federal Energy Program outlined by President Carter, under which new taxes, conservation measures, and fuel availability may affect their operation. Uncertainty with respect to fuel freight rates may also have an effect on cogeneration plans at the Mojave plant.

Agreement with the utility will depend on the ability of California Portland Cement to wheel power to its Colton plant at a favorable transmission charge. In addition, a favorable price from Edison for power made available to the grid and a favorable peak demand charge in case of turbine or waste heat system failures must be obtained. California Portland Cement believes they can obtain an attractive agreement from Southern California Edison because the utility cannot build any more central power stations; thus there is an incentive for the utility to increase its generating capacity through cogeneration.

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VII. TECHNICAL DATA

A. PROCESSING EQUIPMENT

| Type | No | Age, Yr | Life Expectancy, Yr | Type of Energy Used | Duty Cycle | Maintainability and Reliability Record | Location (Clustered vs Scattered) | Future Plans E = Expansion M = Modernization R = Replacement |
|-------------------------|----|---------|---------------------|---------------------|------------|--|-----------------------------------|---|
| Package boiler (15 psi) | 1 | 10 | 10-15 | #6 fuel oil | Steady | None | Clustered | None |
| Kilns | 2 | 22 | 10-15 | Coal | Steady | 9 or more months per yr on 3 weeks off | Clustered | M, R |

California Portland Cement plans to modernize and expand the Mojave plant, possibly doubling its capacity. The degree of expansion depends, in part, on the anticipation of a favorable cement market, a permissive consideration from the Kern County Air Pollution District, the ability to obtain adequate cooling water, and attractive rates with the Edison Company for cogeneration.

B. PROCESS ENERGY PROFILE

1. Electrical Demand

The Mojave plant has a peak load of 18 MWe and an average load of 10.43×10^6 kWh/mo. The baseload is distributed as follows: grinding mills (11), 65%; kiln plans and screw drive elevators, 20%; miscellaneous, 15%.

The cement plant is a continuous operation with no significant variation (less than 5%) during a 24-hour period. Load variation occurs only in response to a kiln shutdown in which case raw mills, blowers, and kiln motors are turned off. The plant's electrical demand decreases by 20% for each kiln down.

The utility charges include a total kilowatt-hours used at 2.4¢/kWh and a monthly peak demand charge (kWh used in 30-minute period).

In practice, the plant operators try to establish peak demand at the beginning of the month. If, say, a kiln is down at the beginning of the month for a three-week repair, California Portland Cement may elect not to start it up until the first of the next month in order to save on electric costs.

The electrical load variation is not seasonal; rather, it depends on the demand for cement and the failure rate of the kilns. The average time between failures for each kiln is nine months and the downtime is approximately three weeks. All five kilns are in operation about 70% of the time and four kilns are concurrently operable about 96% of the time. The demand for cement appears good for the rest of this year and California Portland Cement wants to keep up the maximum output rate for as long as possible.

2. Steam Load

There is no process steam involved in the production of cement.

3. Fuel Use

The fuel options for the Mojave plant are natural gas, residual oil, petroleum, coke and coal. Of these, coal is the cheapest and most available since California Portland Cement owns its own coal mine in Price, Utah. Half the cost of the coal is transportation costs, which is \$15.60/ton. A unit train for coal supply could reduce the cost by \$4/ton. Thus, California Portland Cement will be able to reduce their fuel costs if they can use enough coal. Each kiln requires six tons of coal per hour, or 4.7 million Btus per ton of clinker produced.

VIII. KEY PROBLEM AREAS

The main problems associated with cogeneration implementation are:

- (1) Obtaining favorable wheeling and standby power charges.
- (2) Meeting air quality requirements and their economic effects on modernization and cogeneration plans.

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APPENDIX A-3

COGENERATION SITE REPORT
PETROLEUM REFINING INDUSTRY

EXXON COMPANY, U.S.A.
BENECIA

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APCD: Bay Area
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This site report is based on notes taken by survey team members during visits to the plant, telephone conversations with plant personnel, and various reports furnished by the company. The report has been reviewed and approved by the company. The opinions, attitudes, and conclusions expressed in the report are those of the company and not necessarily those of the Jet Propulsion Laboratory.

I. GENERAL INFORMATION

The Benecia Refinery is located approximately 20 miles northwest of San Francisco along the Carquinez Straits. The refinery is constructed on three parcels of land that constitute an Industrial Park. Excluding the right-of-ways to connect the three parcels, the refinery encompasses 398 acres.

The refinery was dedicated on October 3, 1969. It produces fuel products no heavier than diesel fuel. It was designed to produce a yield of 68 percent motor gasoline, 29 percent distillate fuels, and 8 percent of other saleable products. It is a "sour" plant in that it processes high sulfur crude oil. The capacity of the Benecia Refinery is 88,000 barrels of crude oil per calendar day.

The plant was designed to process high sulfur crude oil and to produce motor fuels. It does not make heavy products such as asphalt, but refines the "bottom of the barrel" so that a maximum of lighter (high market value) products is produced. As a consequence of this design, the Benecia refinery uses more energy per barrel of crude than does a typical refinery. In fact, it uses about twice as much energy per barrel of crude in its processing because the heavier molecules need to be worked twice the normal amount in order to break down the chemical structure. Each process is efficient, but there are twice as many processes compared with many refineries.

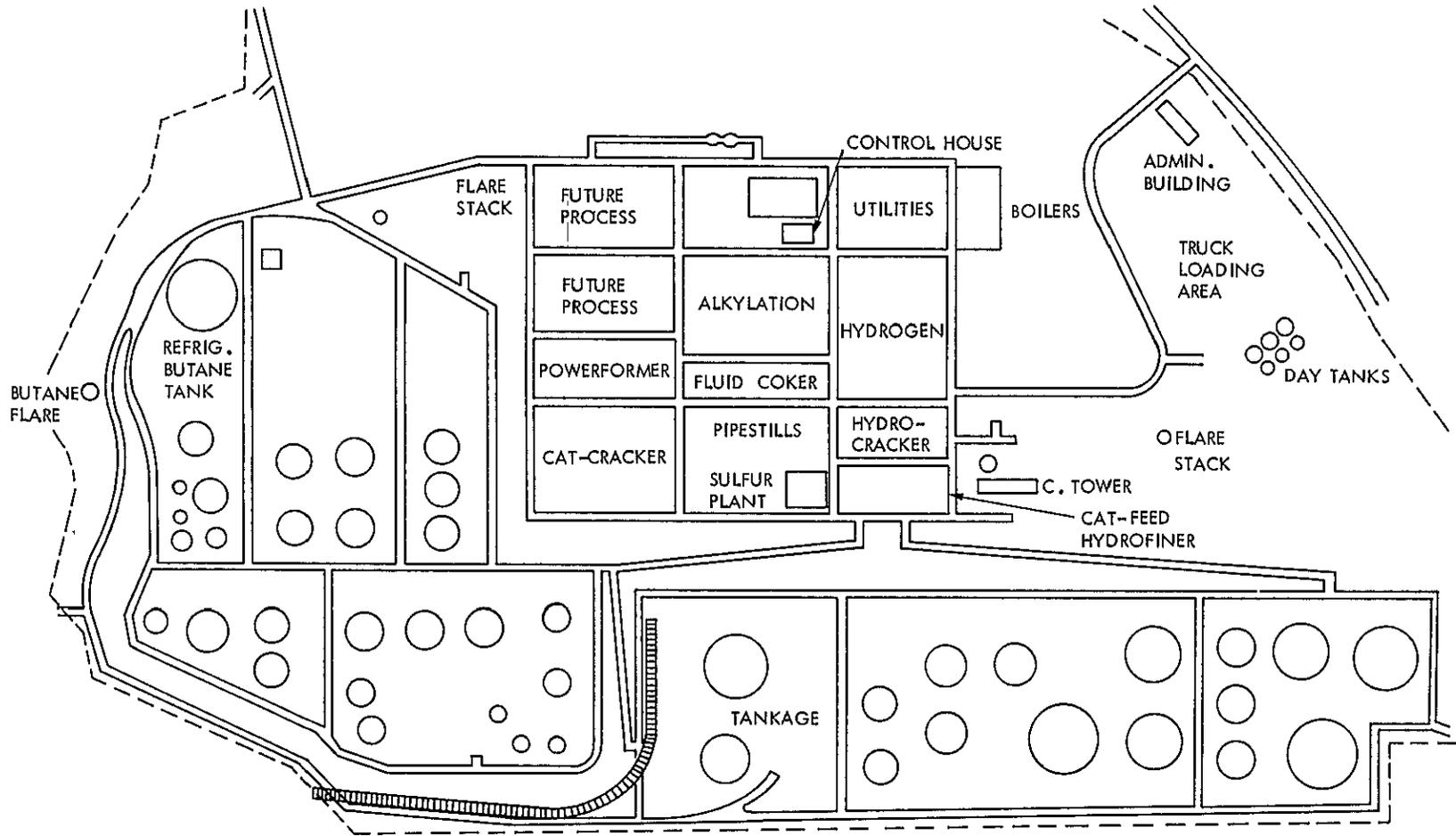
The Benecia Refinery is highly integrated; i.e., there is a minimum of intermediate tankage (storage); the hot stream from one process feeds into the next. Thus, with continuous flow, the modern design conserves energy. Because the plant was constructed in the late 1960s, it incorporated many advanced design concepts, and it is highly automated and centrally controlled.

An important trade organization for the petroleum industry is the American Petroleum Institute, and the Oil and Gas Journal is a widely distributed publication for disseminating information of interest to the industry.

II. PLANT PROCESSING OPERATION

The Benecia plant layout is shown in Figure 1. Figure 2, the plant flow diagram, shows the location of the furnaces used to heat hydrocarbon streams, the gas turbines with waste heat boilers, and the hydrogen plants.

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Figure 1. Benecia Refinery Layout

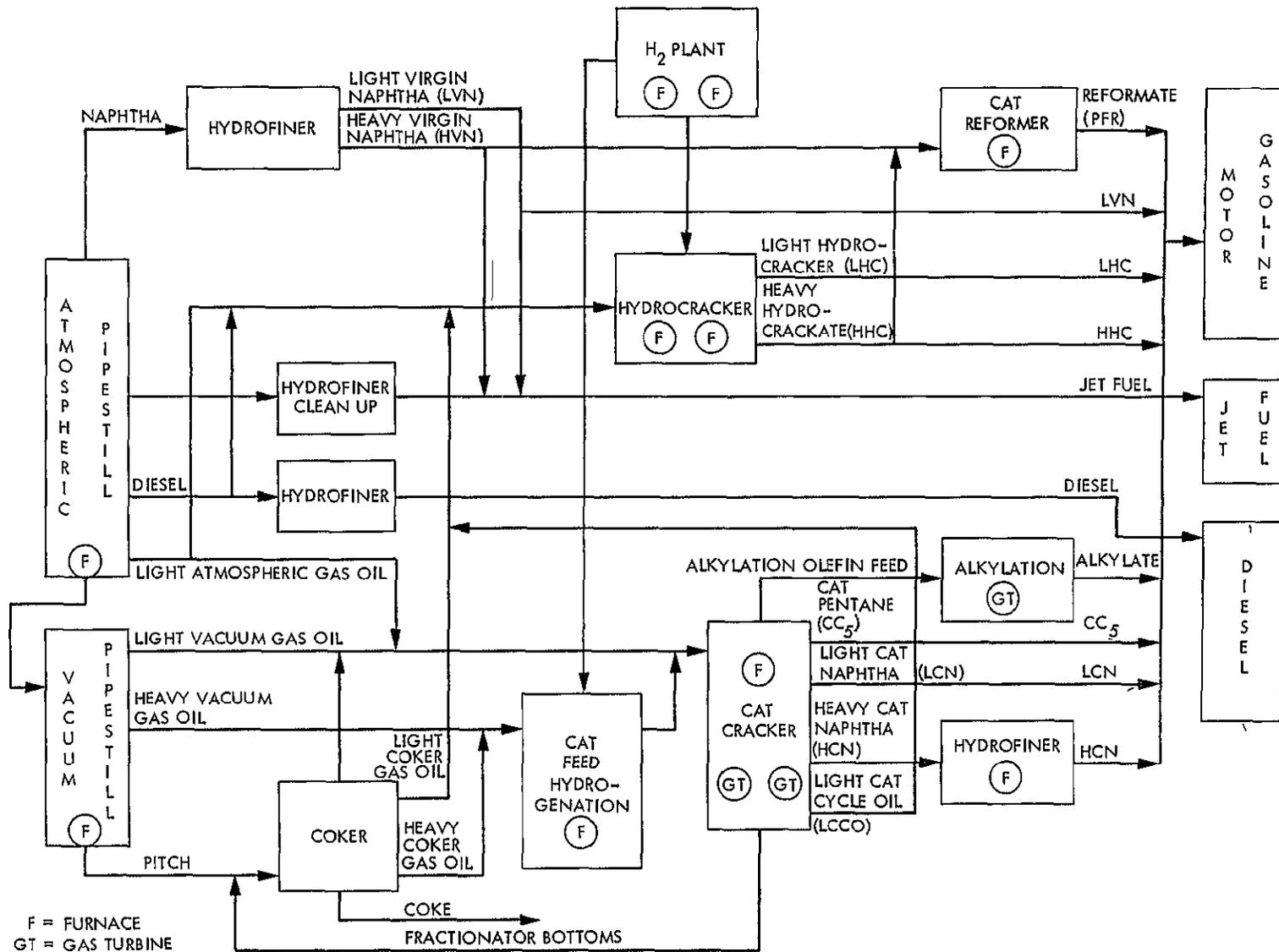


Figure 2. Benecia Refinery Flow Plan

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III. COGENERATION POTENTIAL

The Exxon-Benicia attitude toward innovation and advanced technology is progressive, and while at the present time there are no cogeneration plans, they would be willing to follow the examples of other Exxon refineries and establish a working relationship with the local utility to implement cogeneration.

The following options exist for the refinery:

- (1) Sell fuel gas and liquid fuel to the utility in exchange for sufficient electricity and steam to meet forecast needs. In addition to the exchange, additional operating efficiencies would likely lead to integration of refinery and power plant fuel systems mutually beneficial to the refinery and the utility. The preferable location for the power plant would be in the Benicia Industrial Park as close to the refinery as practical. Other Bay Area refineries having utilities located adjacent to or in the refinery are Lyon Oil, Shell Oil, and Union Oil.
- (2) Cogenerate electricity and process steam, and sell the by-product excess power to the utility. There are no Exxon sister facilities in California for wheeling or sharing of electric power. Current PG&E rates for by-product power (1.4¢/kWh) are not adequate. If the refinery participates in cogeneration, they will likely have to shut down their existing boilers.

IV. ECONOMIC CONSIDERATIONS

Exxon investment philosophy is to invest in processing units, oil production, and discovery while purchasing utilities and services when that is practical. The rate of return required is risk dependent, but the actual value was not obtained. Life matching of components is not a constraint; new equipment will be replaced if it is economically feasible. Investment depends on whether the product will have a strong market over the lifetime of the equipment.

Exxon-Benicia would need a favorable tariff for cogenerated electricity that is sold to the utility. At current rates (1.4¢/kWh), the refinery produced fuel costs are barely covered.

V. ENVIRONMENTAL ISSUES

The New Source Review Rules inhibit expansion or major plant modifications. Exxon and/or PG&E will not likely be permitted to build unless they can offset new facility pollution with a decrease in regional emission burdens. For example, if a new process puts 10 lb/hr of SO_x into the atmosphere, the Bay Area Air Pollution Control District (BAAPCD), California Air Resources Board (CARB), and the Environmental Protection Agency (EPA) will likely not approve a plan that removes less than

Table 1. Total Refinery Emissions

| Emissions | Allowable Standards | Actual Emissions |
|--|---|---|
| Particulates (lb/hr or tons/yr) | Main stack 40 lb/hr based on process weight | 0.8 T/D (1975 BAAPCD data) |
| S (micrograms/m ³) | No regulation | No estimate |
| SO ₂ (ppm) | GLM 0.04 ppm and 6,000 ppm | GLM max. day av. 0.03 ppm 40 T/D (1975 BAAPCD data) |
| SO _x | SGU stack SO ₃ expressed as H ₂ SO ₄ . 0.08 gr/dry cubic foot gas. | No estimate |
| NO _x (milligrams/m ³) | New or mod. heat transfer greater than 250 Btu/hr 125 ppm gas fired | 9.8 T/D (1975 BAAPCD data) |
| CO | No regulation | 4.2 T/D (1975 BAAPCD data) |
| Photochemical oxidants | No reg., but smog alert called when BAAPCD GLM exceeds 0.2 ppm/hr. | No estimate |
| Hydrocarbons | 15 lb/hr per emission point unless exempt | 9.1 T/D (1975 BAAPCD data) |
| Others | | |

12 lb/hr, a 1.2 ratio. Table 1 compares 1975 refinery emissions with regulatory limits.

VI. INSTITUTIONAL ISSUES

The refinery is open to the possibility of establishing a sales or barter arrangement with PG&E. Should PG&E build a power plant near them, Exxon would sell fuel to the utility, and the utility could sell steam and electricity to the refinery to be used for shaft work. This kind of an arrangement is quite familiar to Exxon. For example, under a cooperative agreement, a New Jersey utility has been supplying steam since 1957 to an Exxon Refinery from its nearby power plant at Linden, N.J., in exchange for fuel and boiler feed water. In addition, Exxon supplies additional low sulfur fuel oil to the utility to meet their total utility station requirements. Should PG&E construct a power plant nearby, Exxon prefers that PG&E own it. Exxon has no interest in becoming an electrical utility.

VII. TECHNICAL DATA

A. PROCESS EQUIPMENT

Most pumps are electrically driven, but some spare pumps are driven by 600 psi steam, which expands into 125 psi steam. Four major compressors are driven by combustion gas turbines exhausting to waste heat boilers. Others are driven by either condensing or extraction steam turbines. Figure 1 shows the location of most of the major onsite equipment.

B. PROCESS ENERGY PROFILE

1. Electrical Demand

All normal power for the Benecia Refinery is purchased from PG&E. A small steam-driven generator provides emergency power for the instrument power requirements. In addition to the refinery proper, outlying loads, such as waste water treating, the crude pier, the product pier, and the ballast water area are served from local PG&E 12-kV overhead distribution lines.

Power for the refinery proper is received over two 12-kV overhead circuits from the PG&E area substation. Each of the two circuits is capable of supplying the entire refinery.

Benecia has a 39 MW demand with a 90 percent load factor. The plant thus has an almost uniform demand. The monthly electric bill, at 4+ ¢/kWh, is over \$1,000,000. Except for breakdowns and subsequent startups, the load is constant. The largest motor is the 8,000 hp hydrogen compressor, which is the biggest single electrical user in the refinery.

2. Steam Load

The Benecia Refinery is self-sufficient in the generation of both 600 psig and 125 psig steam. This is accomplished by the operation of four waste heat boilers utilizing gas turbine exhaust for heat to generate steam, and four additional fuel-fired boilers. In addition, some of the process units have internal steam generation capabilities. These eight boilers have a combined total emergency capacity of 1.2×10^6 lb/hr at 600 psig and at 750°F. Nominally, 600,000 lb/hr is used with 100,000 to 150,000 lb/hr generated by the four standby utility boilers.

Much of the refinery 125 psig steam is supplied by letting down 600 psig steam through steam turbine drivers at the various process units. Swings in demand are met with the Powerformer recycle gas compressor extraction steam turbine. If for some reason the supply

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is not sufficient, a letdown station and desuperheater can convert 600 psig steam directly to 125 psig steam.

3. Fuel Uses

Exxon is an aggressive company in all areas, including energy conservation. Since 1972 they have reduced their energy consumption per unit of input by 15 percent. In so doing, they have concentrated primarily on increasing their furnace and heat exchanger efficiencies.

Exxon-Benecia uses fuel equivalent in heat content to approximately 10,000 barrels/day of oil. Most of the fuel used is by-product gas produced by the various process units. Some natural gas is used as a raw material feed for the hydrogen reformers. Fuel use for steam generation is primarily refinery fuel with a very small amount of diesel fuel used for supplemental firing to provide a steady flow.

VIII. KEY PROBLEM AREAS

- (1) Meeting offset provisions of the New Source Review Rules.
- (2) Establishment of an equitable utility rate structure for the purchase of industrially-generated electrical power by a utility.

APPENDIX A-4

COGENERATION SITE REPORT
FOOD PRODUCTS INDUSTRY

HUNT-WESSON FOODS, INC.

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APCD: South Coast Air Quality Management District
AQMA: South Coast

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This site report is based on notes taken by survey team members during visits to the plant, telephone conversations with plant personnel, and various reports furnished by the company. The report has been reviewed and approved by the company. The opinions, attitudes, and conclusions expressed in the report are those of the company and not necessarily those of the Jet Propulsion Laboratory.

I. GENERAL INFORMATION

Hunt-Wesson (H-W) is a subsidiary of Norton Simon, Inc. (NSI) and is a national leader in the production of tomato-based food products and edible oil. The Fullerton plant, located in Orange County, is basically two separate and distinct operations. The Hunt side of the house is a seasonal canning operation (June 16th to November 20th); the Wesson side is an all-year-round refining and bottling operation. The one common denominator is that all the boilers are centrally located near the cannery and the operation and maintenance is the responsibility of the cannery personnel.

II. PLANT PROCESSING OPERATION

The refinery process manufactures edible oil for the consumer market and shortening for the industrial market. Crude oils are purchased from the Chicago Commodities Market; they are then refined, hydrogenated, deodorized and bleached to produce the final product.

The cannery produces tomato-based products for both the consumer and commercial markets. The general operation consists of receiving freshly picked tomatoes from trucks, then cleaning, processing, canning, and packaging them for shipment.

III. COGENERATION POTENTIAL

In the refinery process there is a potential for a 1.6 MWe cogeneration system at a capital expenditure of \$1.0 to \$1.5 million. This plan would meet the refinery steam load and the generated electricity would be utilized internally. Two options were considered. The first option is to operate two steam turbines (750 kW each) with 850 psig, 825°F intake steam and 150 psig saturated exhaust steam. The second option is to operate two gas turbines utilizing a waste heat boiler to produce 150-psig saturated steam. Thayer and Associates, an engineering firm located in Newport Beach, performed an economic feasibility study of energy conservation for the refinery. All results of this study are the sole possession of Thayer and Associates and were not made available. Their basic concept for the total operation (cannery and refinery process) would be a dual fired boiler (natural gas and fuel oil) furnishing 600 psig steam to three or four steam turbines with 165-psig saturated steam exhaust. Thayer and Associates has also recently completed a study for the entire plant but results were not made available.

Cogeneration is of definite interest to Hunt-Wesson's Fullerton plant, and if it is deemed economically feasible, they will most likely install a unit. The actual location would be near their present boilers. With space at a premium, this could present some installation problems and high construction costs.

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IV. ECONOMIC CONSIDERATIONS

The capital investment criteria for production line equipment is normally a 25 percent return-on-investment. For fuel saving equipment (such as that for cogeneration) the required return-on-investment (ROI) is 10-15 percent with a four to five year payback period. Lower ROI's are acceptable for fuel saving equipment because of perceived increases in fuel cost.

Capital investments for energy conservation, which includes heat losses and water quality control, for H-W's eight U.S. based canneries range from \$250,000 to \$300,000 per year. The H-W Fullerton Plant is one of the largest and \$500,000 was spent last year for this plant in the cannery alone. In the next two to three years the expenditures for energy conservation and process changes could go as high as \$2.5 million.

Life matching of their existing equipment is part of their economic analysis. For cogeneration H-W would salvage three boilers and save one for back-up. When H-W performs economic studies they use current prices and perform parametric analysis for future fuel price increases.

V. ENVIRONMENTAL ISSUES

The main source of air pollution is from the boilers. The plant is continuously spending funds for air pollution and water quality control equipment. H-W would like to see more stable air quality standards so they can perform efficient long-term financial planning.

If cogeneration is implemented, H-W will be burning more fuel, thereby increasing emissions and thus increasing their air pollution problems. If environmental regulations require H-W to reduce production in order to install cogeneration they will not proceed with the plan.

The New Source Rules in H-W's opinion, act as a negative incentive for cogeneration. Although H-W would be burning more fuel, the utility would be benefiting since it theoretically reduces fuel consumption at the utility's power plant. H-W feels there should be a trade-off between them and the utility since, from an overall energy conservation viewpoint, cogeneration is more efficient and they should not be penalized for the implementation while others benefit.

VI. INSTITUTIONAL ISSUES

H-W is investigating cogeneration very seriously; their basic requirements for implementing cogeneration depend on economics and their ability to satisfy air quality regulations.

They also feel that if surplus power was available from their cogeneration facility, and a power sale agreement was proposed to the utility, the utility company would not be willing to pay a reasonable price for this power.

At present, H-W is concerned with how Congress may modify the national energy plan. They perceive cogeneration implementation incentives as those which would include tax credits exemption from oil or gas curtailments, and fair utility power sale agreements. H-W would like the CPUC to be more flexible in determining gas curtailment implementation. The food industry cannot afford a fuel shortage during the canning season. Hunt-Wesson would prefer to be exempt from any gas curtailment schedule or be given a higher priority.

VIII. TECHNICAL DATA

A. PROCESSING EQUIPMENT

There are four boilers, all located in one area near the cannery, with a total rating of 300,000 lb/hr as shown below:

| <u>No. of boilers</u> | <u>Rating (lb/hr)</u> | <u>Age (yrs)</u> |
|-----------------------|-----------------------|------------------|
| 2 | 45,000 (each) | 38 (each) |
| 1 | 58,000 | 20 |
| 1 | 150,000 | 7 |

There are other types of equipment and drives such as electric motors, fans, pumps and conveyors and plans call for the installation of economizers on two of the boilers. The plant is being continuously upgraded with a normal maintenance program; two men operate and maintain the boilers.

There are no plant expansion plans at this time. If plant expansion is initiated in the future, there will be a problem with space. Modification of the process itself, however, could eliminate one of the old boilers.

B. PROCESS ENERGY PROFILE

1. Electrical Demand

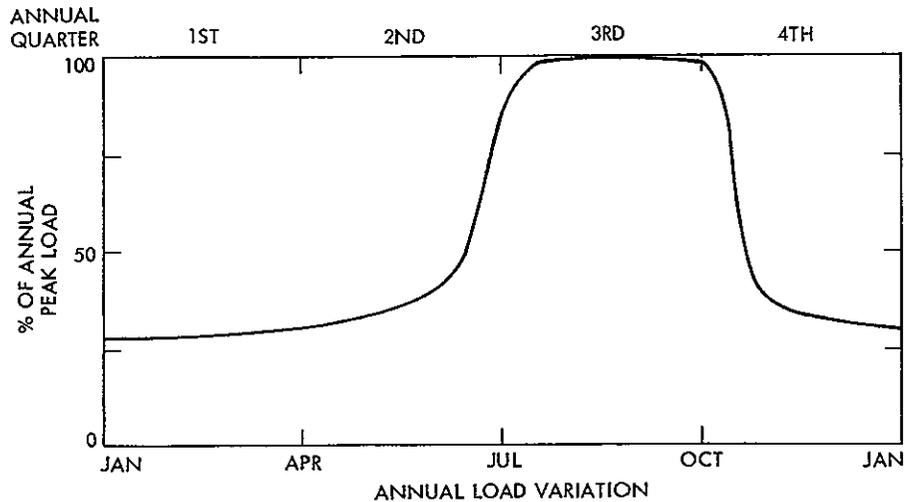
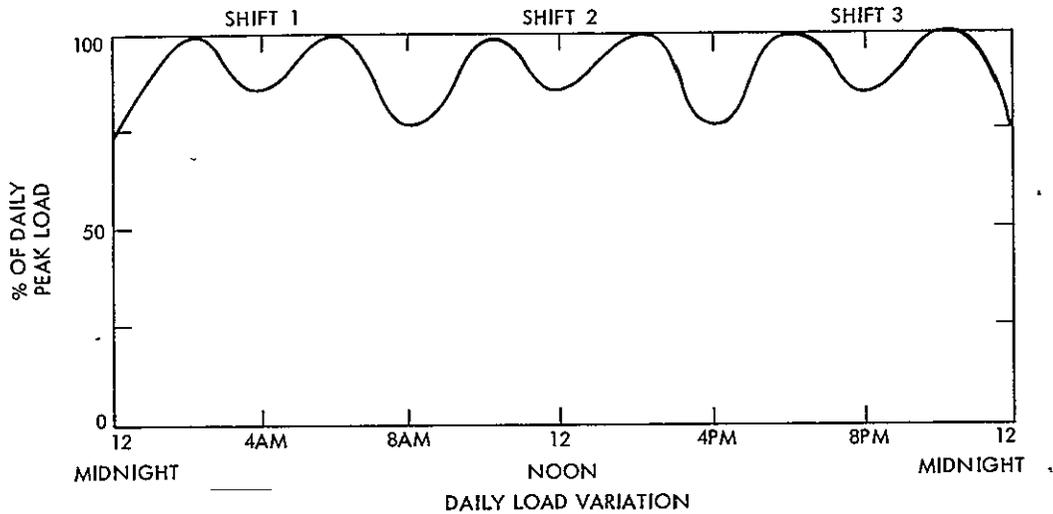
The plant's utility bill is \$500,000 per year with an annual usage of 19×10^6 kWh and a 76 percent to 78 percent power factor. The

variation due to the canning season is reflected in the electricity usage values shown below:

| <u>Month</u> | <u>Monthly Usage</u> (10^6 kWh) | <u>Maximum Demand</u> (MWe) |
|-----------------------|---------------------------------------|--------------------------------|
| February (off-season) | 1.0 | 2.1 |
| July (canning-season) | 2.4 | 4.2 |

For five months out of the year they operate at full load and the remaining seven months at one-third load, with only the refinery operating. Normally, the plant operates on a 24-hour, 7-days-a-week schedule.

Variation with respect to daily and annual electrical load is shown in the following diagrams:



The major valleys occurring in the daily load variation curve are for shift changes and the minor valleys for meal breaks.

For the annual load variations the obvious peak occurs during the canning season (July 16 to November 20), and remaining months are when the refinery process is in operation (24 hours per day, 7 days per week).

2. Steam Load

There are four boilers, located together and having a total maximum capacity of 300,000 lb/hr. During the canning season all of this steam is utilized at 165 psig, saturated condition. In the off-season the load is 30,000 to 40,000 lb/hr with the same steam quality. The condensate return is 10 percent minimum and 60 percent maximum.

The following steam load reflects the difference between the canning season and off-season values:

| <u>No. of Months</u> | <u>Monthly Usage</u> (10 ⁶ lb) | <u>Total Usage</u> (10 ⁶ lb) |
|----------------------|--|--|
| 7 (off-season) | 25 (min) | 260 |
| 5 (canning-season) | 120 (max) | 490 |
| | ANNUAL TOTAL | 750 |

Daily and annual steam load variation is similar to the electricity load diagrams.

3. Fuel Use

The boilers burn natural gas with #2 fuel oil as standby, and have the capability to run on either fuel. Presently, natural gas costs 17¢ per therm and #2 fuel oil costs 24.6¢ per therm.

The plant is on a P4 priority for gas curtailment and in November 1976, Southern California Gas Company notified H-W they would be curtailed during the year. Preparations were then made to burn low sulfur (S = 0.5%) fuel oil, but because of the mild winter total curtailment was not implemented and oil was burned for only a couple of months.

A five-day capacity fuel storage tank was installed two years ago in anticipation of natural gas curtailment. It holds 288,000 gallons above ground and cost \$150,000 to install. This fuel is used as a buffer tank to supply two tanks of 10,000 and 20,000 gallon capacities which are used for the operation. When practical, the plant operates from the oil delivery trucks.

A major concern is that, when gas is curtailed, fuel oil may also become unavailable, since refineries will supply their long-term contract customers first. If a curtailment occurs during the canning

season, the financial losses would be devastating. Conversion to coal is not feasible due to the air pollution restrictions in the Fullerton area. If natural gas and fuel oil were not available, the plant would be forced to shut down. H-W has two consulting firms working on their fuel utilization concerns. One consultant is investigating to determine what fuels are economical for H-W to burn and still meet the air pollution requirements; the other consultant is determining the most efficient operation of the boilers using various fuels. The outcome of these studies is uncertain at this time.

VIII. KEY PROBLEM AREAS

The major problem areas that hinder cogeneration implementation are as follows:

- (1) Interpretation of air quality regulations as they apply to the H-W operation and plans for cogeneration implementation.
- (2) Inflexible CPUC gas curtailment decisions during the canning season.
- (3) Uncertainty associated with legislative action, utility negotiations, and technology implementation.

APPENDIX A-5

COGENERATION SITE REPORT
ENHANCED OIL RECOVERY

HUSKY OIL COMPANY

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R. H. Roda

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This site report is based on notes taken by survey team members during visits to the plant, telephone conversations with plant personnel, and various reports furnished by the company. The report has been reviewed and approved by the company. The opinions, attitudes, and conclusions expressed in the report are those of the company and not necessarily those of the Jet Propulsion Laboratory.

I. GENERAL INFORMATION

Husky Oil is a large, integrated, independent oil company which was founded in Wyoming 40 years ago. Their Pacific Coast operation includes oil fields in south-central California near Santa Maria, and some offshore exploration in Southern California. The California fields are primarily heavy oil fields requiring enhanced oil recovery methods such as thermal recovery.

Thermal recovery includes cyclic steam stimulation (also known as steam soak, push-pull, and huff-and-puff), steam flooding (steam drive) and fireflooding. It is a vital tool in the task of increasing heavy oil production.

Husky Oil has an enhanced oil recovery (EOR) project in their Paris Valley field (100 miles north of Santa Maria) for the development of new oil recovery technology using the "cyclic steam stimulation" and "fire flood" methods for a "combination thermal drive". Husky Oil is considering a cogeneration project in conjunction with their EOR program in the East Cat Canyon field, 8 miles southeast of Santa Maria. Presently Husky Oil produces 4000 barrels of oil per day (BOPD) in the area. Its neighbor, Getty Oil, produces 6000 BOPD.

Cogeneration projects associated with EOR have been studied for a number of years. A 1974 study initiated by PG&E stated that Texaco and Getty Oil, among others, have potential cogeneration capacities of 210 MWe and 280 MWe, respectively. These capacities correspond, respectively, to steam loads of 1.6×10^6 lb/hr at 900 psig for Texaco with a 15-year demand and 2.0×10^6 x lb/hr at 1000 psig for Getty with a 20-year demand. An engineering firm is presently performing an ongoing review of the Texaco, Getty, and Husky cogeneration programs for PG&E. The study will include conceptual design, review of components, development of alternatives, recommended systems, consideration of fuel types and performance of specific designs. Texaco and Getty are presently in cogeneration agreement negotiations with PG&E.

Information sharing on EOR is open and free within the petroleum community. Technical information, published papers and reports are made available as public record. The Oil and Gas Journal is a leading publication in the oil industry and locally the Western Oil and Gas Association is of service. DOE publications and the Journal of Petroleum Technology are probably the most useful publications. Most oil companies are active in EOR, with Getty, Shell, and Chevron generally considered among the most innovative.

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II. PLANT PROCESSING OPERATION

Oil is obtained using cyclic steam stimulation by injecting steam for several weeks and then producing the well for six months to a year, or until the production rate declines to near the pre-steam value. At this point, steam is again injected and the cycle repeated. Increased oil production from cyclic steam stimulation is primarily due to the resulting decrease in viscosity and from well-bore cleanup.

The generators used by Husky Oil in its Paris Valley field are fixed, and insulated lines distribute the steam to various wells. In the steam injection phase a mixture containing about 80 percent steam and 20 percent water is injected into the ground. This permits simpler and less expensive operation of the steam generator. Getty Oil Company is presently performing a steam flood pilot in their Cat Canyon field just west of Husky's East Cat Canyon field. Getty's steam generator system with four injection wells, is shown in Figure 1

Steam generators can be fired with natural gas, propane, or crude oil. Natural gas is the easiest to use but is becoming less available and more expensive. If the crude contains over 0.5 percent sulfur, a stack gas scrubber is required to remove the sulfur dioxide to meet air pollution standards. The heat conduction from the steam which channels out, affects a relatively large amount of the reservoir and the wells are sometimes left shut-in after injection to enhance the spread of heat.

A well stimulated by cyclic steam may produce over 150 BOPD after steam stimulation compared to 5 BOPD before stimulation. It can usually produce steam condensate for a few days, then the oil rate increases sharply, peaks, and finally declines with time. The optimum point to resteam is a matter of economics; some wells are resteamed 15 to 20 times. At some point the project is generally converted to a steam flood when about one-half the wells are converted to permanent injection (as opposed to cyclic steaming when all wells are part-time injectors). The response varies markedly depending on the reservoir properties. Most successful projects are in reservoirs thicker than 30 feet and at a depth less than 3000 feet where the oil is viscous but mobile.

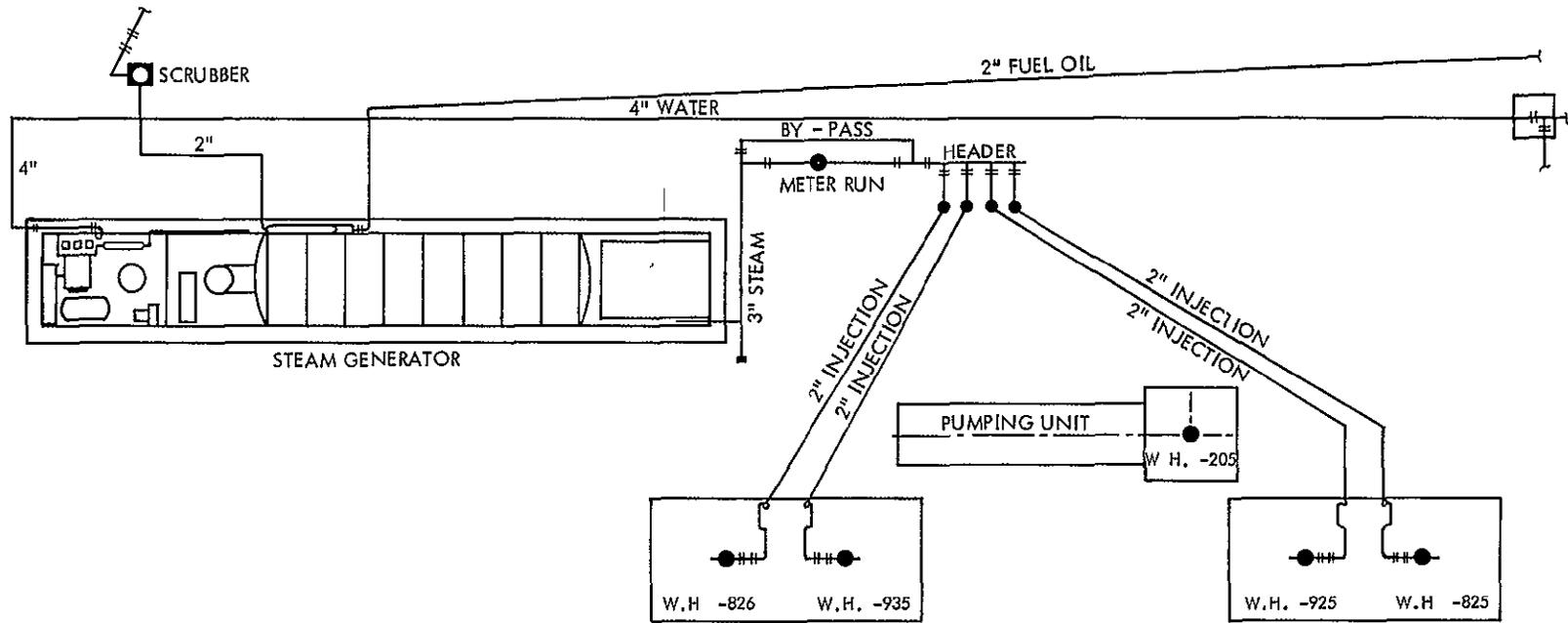
III. COGENERATION POTENTIAL

In current steam flood operations, three out of four barrels of oil recovered are shipped to the refinery for processing and one barrel is used as fuel for the steam generation in the field. The amount of steam to be provided from a cogeneration plant in the East Cat Canyon for recovery operations is under consideration.

With the concept of cogeneration plants being located in the oil field, a new market is established for those companies involved with heavy oil operations. Cogeneration will produce electricity for consumers and steam for the oil company EOR operation, enabling a mutual benefit. The fuel for the power plant is recovered, sold, and used at the same general location, reducing transportation costs for the oil company and assuring the utility of an uninterrupted fuel supply.

PG&E is studying the feasibility of developing an oil field project. So far, a combined cycle plant fueled with heavy crude and/or a cogeneration project are considered candidate systems. The tentative location is in the vicinity of the heavy oil field operations near Santa Maria, possibly near an existing PG&E substation. Figure 2 shows

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ERDA PROJECT LOCATION
50 MM BTU/HOUR STEAM GENERATOR,
INJECTION WELLHEADS AND
W.H. -205 PRODUCING WELL

Figure 1. Getty Steam Generator System

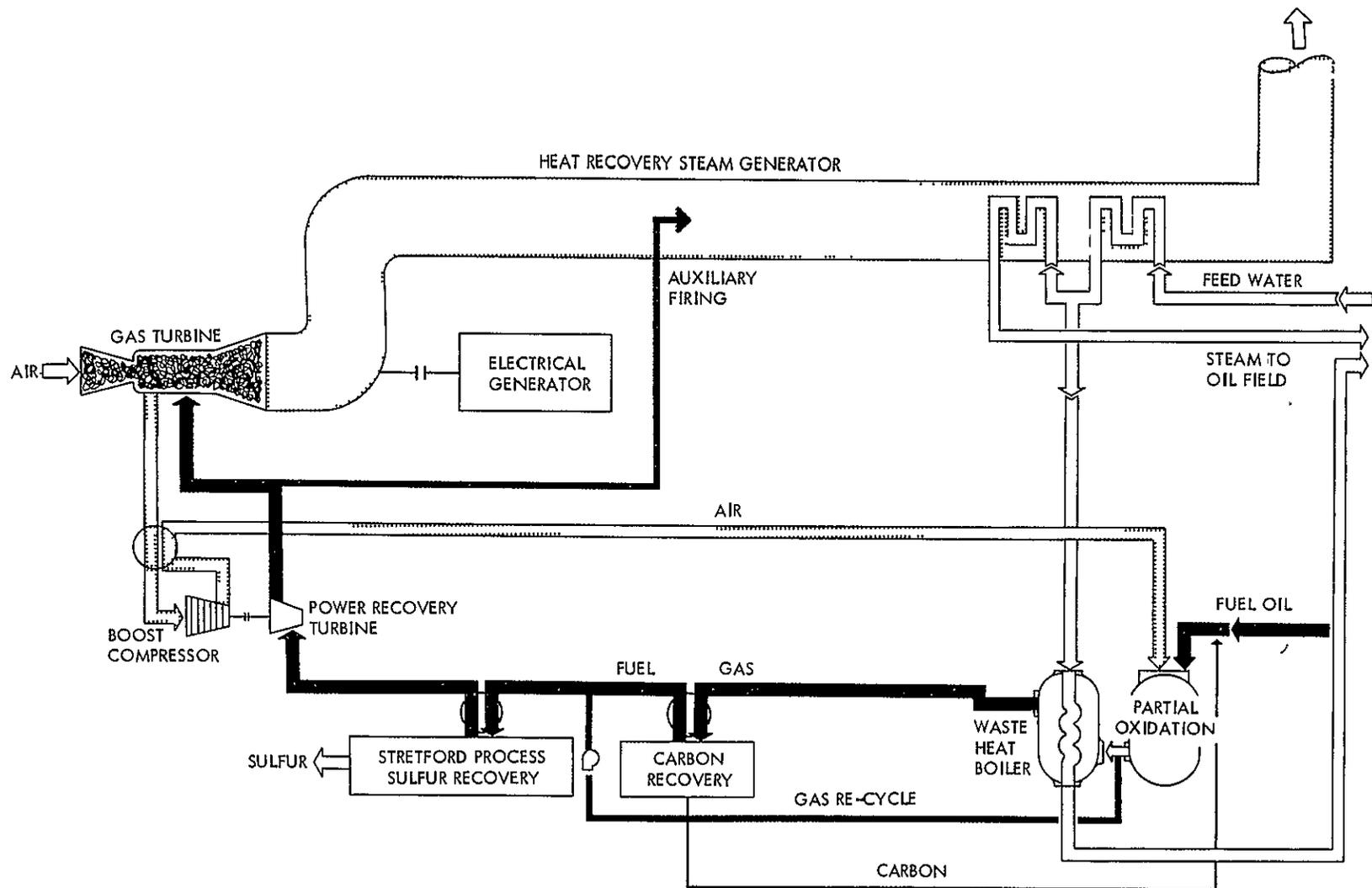


Figure 2. Oil Field Cogeneration Project - Possible Configuration

a possible configuration for an oil field cogeneration project. Husky and/or some other company would tentatively provide fuel to PG&E and receive steam. The power plant would be located on a parcel of land in the East Cat Canyon field. If the fields produce more oil than anticipated, PG&E might expand their power plant. It is now estimated that in the fields only 3 percent of the oil is recoverable by primary recovery, and with steam injection up to 50 percent of the remaining reserves may be recoverable.

The steam will be delivered to the field through a distribution system with a probable maximum radial distance of one mile. Husky's steam load would be on the order of 0.83×10^6 lb/hr (20×10^6 lb/day) at 1300 psig and approximately 750°F. Typical steam injection pressures for East Cat Canyon range from 1300 to 2000 psig at temperatures from 400 to 600°F.

Husky Oil has two heavy oil reservoirs in East Cat Canyon (deep sand stratas): the Sisquoc reservoir at 2000 feet and the Brooks reservoir at 3000 feet. The Sisquoc sand strata is shared by their neighbors and can be tapped with 1500 psig steam pressure. The Brooks sand strata is totally within Husky's East Cat Canyon field and a 2500 psig steam pressure will be required to recover the heavy oil. Husky Oil feels that 50 to 100 million barrels of heavy oil may eventually be recovered from the Brooks reservoir by steam injection. This magnitude of depth and steam pressure has only rarely been attempted before and is considered a risky venture.

IV. ECONOMIC CONSIDERATIONS

Investment criteria were not obtained; however, energy conservation is an important aspect. Expenditures of approximately \$50-100 million are estimated for drilling the oil wells that will be part of the cogeneration system.

For surface equipment (excluding wells) Husky uses a 14-year double declining balance depreciation method. For the wells the depreciation method for tax purposes is a bit more complicated; the percentage of production for each well is computed on an annual basis with respect to the total reserve for the well. This percentage is prorated to the total cost of the well, establishing a unit production annual cost for each well. Thus, the depreciation is computed as a function of the reservoir life for each well extracting oil from that given reserve.

V. ENVIRONMENTAL ISSUES

Fuels used for steam generators are one major cause of pollution. The on-site heavy crudes (5-6% sulfur content) cause serious environmental problems with SO₂ and NO_x emissions. Present EOR programs have severe environmental problems and could be curtailed. In fact, earlier EOR production estimates are now off by a factor of ten due to restrictive environmental controls.

Husky Oil spends approximately \$150,000 per year on environmental control in California. They have installed stack gas scrubbers to the steam generators in their Paris Valley field. In this way the sulfur dioxide content of the stack gas is reduced to less than 25 ppm by coming in contact with water and ammonia. Husky Oil is currently spending \$4 million for a field gas treatment plant which will treat the hydrogen sulfide (H₂S) in the gas which is presently flared. A chemical engineer spends all his time on environmental issues and a production engineer spends half his time on air and water pollution problems. They cannot budget for long-term items because of the uncertainty in the environmental regulations.

Husky Oil must interact with the Santa Barbara County APCD, which is very strict, the State Air Resources Board, and the Federal Environmental Protection Agency. In addition, it must interact with the County Office of Environmental Quality, the Water Quality Control Board and the State Department of Water and Gas. Water quality control is important and a strict control on the injected water must be maintained before injection to protect the fresh ground water. The County Petroleum Administrator is an overseer for the County government and is interested in all environmental aspects of oil production.

The Husky East Cat Canyon oil field produces a heavy crude oil having the following composite set of properties:

| | |
|------------|---------------|
| API | 7.1° |
| Con Carbon | 15 |
| Sulfur | 6.5% (by wt.) |
| Nitrogen | 0.7% (by wt.) |
| Salt | 40 ptb |
| Vanadium | 370 ppm |
| Nickel | 170 ppm |

The heavy crudes have a higher unit energy value per barrel as compared to the sweet crudes, 6.3×10^6 Btu/bbl as compared to 5.8×10^6 , respectively, but the air pollution problem must be overcome. The gasifier in the cogeneration plant will transform the sulfur in the crude to H₂S which is then further treated to produce marketable sulfur, thus producing cleaner emissions and a sulfur residue. Another by-product of the cogeneration plant will be a low Btu carbon dioxide gas, 110-125 Btu per standard cubic feet (SCF). This compares to natural gas which is on the order of 1000 Btu/SCF.

With cogeneration, Husky Oil anticipates their production can be increased by a factor of four while both reducing emissions and producing electrical power. Husky Oil will be tentatively responsible for the water supply to the cogeneration plant. Water for the steam generator is usually drinking water quality and is treated to prevent scale formation or corrosion in the generator. Husky would establish a well pattern and provide water to the plant through a piping system. The water is on the salinity level of sea water and thus must be treated in a modern water purification plant.

The New Source Review Rules will directly affect Husky Oil. They feel that the offset provision benefits older plants that have an overabundance of old equipment as compared to either a modern plant with the latest antipollution devices or a new plant within the basin with no equipment. Husky Oil falls in the latter category, since at this time they do not own any equipment that can be traded off.

Husky's oil fields are continuously being monitored by environmental agencies. The agencies' actions and decision are not, according to Husky, consistent. If environmental limits are exceeded too often, the oil field could be legally shut down. Should this occur, the wells would sand up, resulting in a serious financial loss.

VI. INSTITUTIONAL ISSUES

Husky Oil is discussing cogeneration with PG&E at a preliminary level. The technical aspects of the cogeneration power plant are the responsibility of PG&E. Husky's interest is in selling crude oil to PG&E and purchasing steam for their future EOR operation.

PG&E wants a long-term guarantee for a continuous supply of oil for the cogeneration power plant. This poses a problem to Husky Oil: If Husky is unable to meet PG&E fuel demands, then \$15/bbl oil might have to be purchased and supplied to PG&E at \$7-7.50/bbl; this would be financially disastrous for Husky Oil. PG&E tentatively proposes to purchase the oil for \$7/bbl (\$4 less than world prices as of August 1977) and escalate at an average price per Btu into their system.

PG&E may compute the purchase value of crude oil by the Btu value of the fuel and sell steam to Husky Oil and Getty Oil based on the Btu value of the steam. The oil-to-steam Btu ratio has not yet been determined. Financial arrangements between PG&E and Husky Oil for this potential project are at this time undetermined and subject to contract negotiations. At the present preliminary stages of discussion one proposal is for PG&E to perform feasibility studies, engineering design, purchase and install equipment, own, operate and maintain the plant, and provide steam to Husky Oil. However, other scenarios are possible. The time table would be on the order of one year for formulation and approval of Husky/PG&E agreements; four years to clear the environmental issues and obtain all necessary permits; and two years for the physical construction for a total of seven years.

VII. TECHNICAL DATA

A. PROCESSING EQUIPMENT

Husky's East Cat Canyon operation is a standard oil field with oil well drilling and pumping equipment, and supporting storage, piping and shipping facilities. At the present time Husky has some cyclic steam activity in this field. Typical steam processing equipment is discussed in the plant processing operation section of this report.

B. PROCESS ENERGY PROFILE

1. Electrical Demand

Husky Oil's East Cat Canyon field utilizes approximately 450,000 kWh of electricity per month at a rate of 3.7¢ per kWh. This is fairly constant all year round, 24 hours a day, for an annual billing of approximately \$200,000. In its Paris Valley EOR project, electrical billings are about \$550,000 per year. Total electric power costs are about \$1,200,000 per year to produce 4000 BOPD.

2. Steam Load

Husky Oil's present steam load in the East Cat Canyon field is nonexistent; however, something like a 20×10^6 pound per day load is anticipated with EOR implementation.

3. Fuel Use

Husky Oil presently uses natural gas in the East Cat Canyon, at a price of \$1.80 per thousand standard cubic feet (MSCF). They also use their own fuel gas. All fuel and electric power is used for pumping operations and supportive equipment.

VIII. KEY PROBLEM AREAS

The major problem areas with respect to cogeneration implementation are as follows:

- (1) PG&E requirement of a long-term guarantee of oil supply for new cogeneration plants.
- (2) Required steam pressure of 2500 psig (for the Husky reservoir at 3000 feet) may be too high with present day technology.
- (3) Environmental monitoring performed in the oil fields is perceived to be too excessive and inconsistent, and the offset provisions in the New Source Review Rules are discriminatory against modern and new plants within the air control basin.

APPENDIX A-6

COGENERATION SITE REPORT
STEEL INDUSTRY

KAISER STEEL CORPORATION
FONTANA PLANT

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H. S. Davis
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APCD: South Coast Air Quality Management District
AQMA: South Coast

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This site report is based on notes taken by survey team members during visits to the plant, telephone conversations with plant personnel, and various reports furnished by the company. The report has been reviewed and approved by the company. The opinions, attitudes, and conclusions expressed in the report are those of the company and not necessarily those of the Jet Propulsion Laboratory.

I. GENERAL INFORMATION

Kaiser Steel Corporation is the nation's tenth largest steel producer, manufacturing approximately 2 percent of the nation's total raw steel output. It is the largest steel producer in the western United States and is the only mine-to-metal steel maker in California.

Kaiser Steel's domestic operations include iron ore mining and processing; coal mining, steelmaking, and finishing; fabricating and manufacturing.

The Kaiser plant in Fontana (45 miles east of Los Angeles) was constructed in 1942 and is the only fully integrated steel manufacturing plant in California. It produces approximately 3.4 million tons of steel products annually but is having difficult financial times with stiff competition coming from the modern Japanese steel mills.

Profitability in 1976, was adversely affected by product mix and by lower profit margins, and market conditions continue to be depressed in early 1977. Consequently, one of the corporation's four blast furnaces has been shut down and only three of its open-hearth steelmaking furnaces are in operation. Approximately 2,000 employees were on layoff as of 28 February 1977.

II. PLANT PROCESSING OPERATION

In the steelmaking process, three basic ingredients - iron ore, coke, and limestone - are put into a blast furnace and reduced to molten iron. This is drawn from the bottom of the blast furnace into specially designed, brick-lined railroad cars. When Kaiser Steel's modernization program is complete, many of these cars carrying molten iron will pass through a hot metal desulfurization facility, where a chemical injected into the hot metal will react to remove and dispose of the sulfur under environmentally controlled conditions (Figure 1). The cars will then proceed to one of two basic oxygen process (BOP) shops, where the molten iron will be converted into steel by oxidizing carbon to precise levels and refined with the use of flux.

From the No. 1 BOP shop, steel is teemed into molds which form ingots. After cooling, the molds are stripped off and the ingots placed in soaking pits for reheating. As needed, reheated ingots are then transferred to the blooming or stabbing mills for initial rolling. Subsequent rolling converts blooming mill products into structural and bar products.

Steel from the stabbing mill may be transferred to the plate mill, where it is rolled into steel plates that may be shipped to a customer or may be further processed into large-diameter pipe; or it may be sent from the stabbing mill to the hot-rolled sheet and strip mill and to other finishing mills or directly to the customer.

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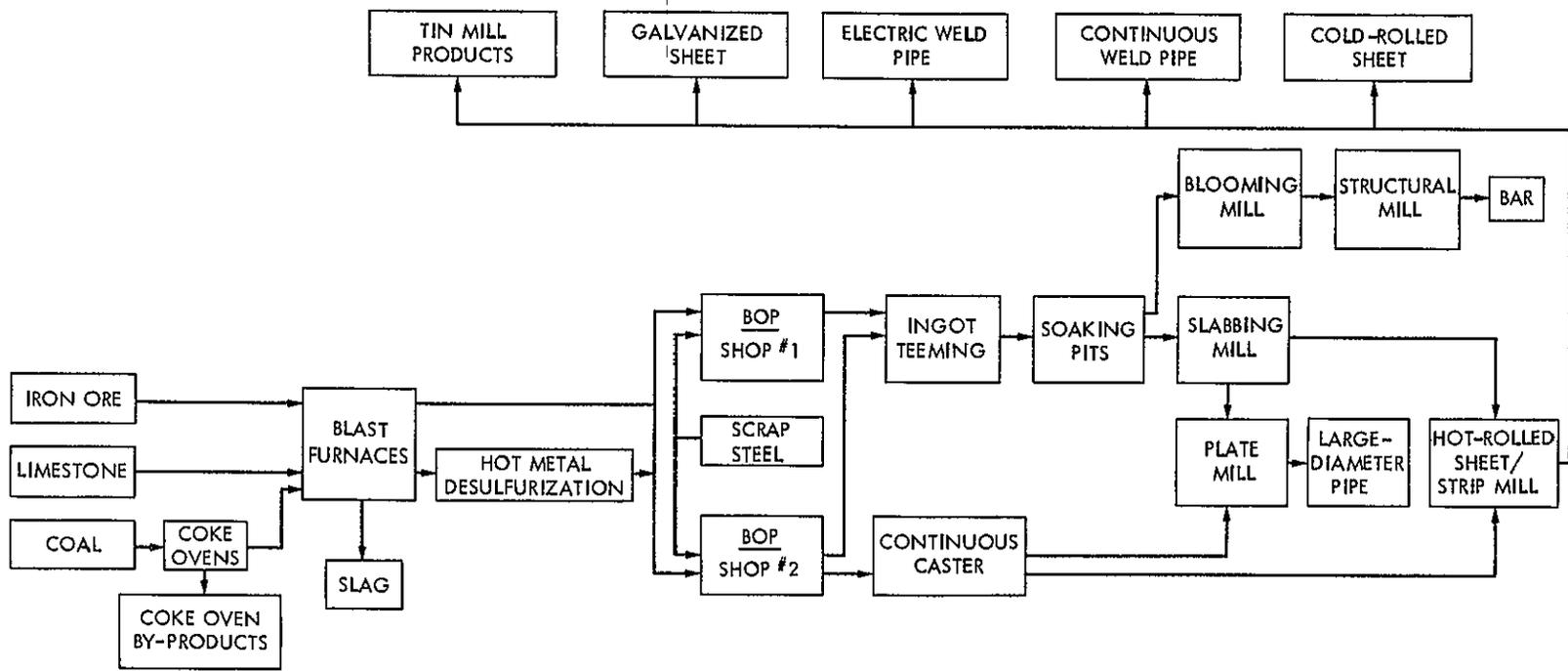


Figure 1. Flow Diagram of Kaiser Steel Process

Some steel from the No. 2 BOP shop (now under construction) will follow the same path. A large part will be fed to a new continuous caster and cast into slabs which will go directly to the plate mill or to the hot-rolled sheet and strip mill. The caster saves several steps in the finishing process and should aid in reducing costs.

Sources of waste heat in the plant include:

- (1) Coke oven gas at 550 Btu/SCF; 400°F-800°F stack temperature.
- (2) Blast furnace gas at 80 Btu/SCF is a function of hot metal fractions and quantity can vary from $1-2 \times 10^9$ ft³/yr.
- (3) Stack gases:
 - (a) Four blast furnace stove stacks at 100-800°F.
 - (b) Two open-hearth furnaces after plant modernization at 300-400°F.
 - (c) Four basic oxygen flare stocks (CO) at 200-300°F.
 - (d) One sinter plant at 300°F.
 - (e) Twenty soaking pit stacks at 300°F.
 - (f) Reheat furnaces at 500°F.
 - (g) Powerhouse steam generator at 400°F.
- (4) BOP gases are difficult to use because of intermittent generation but have an output of approximately 130×10^6 Btu/hr.
- (5) Soaking pits $6-10 \times 10^6$ Btu/ton.

III. COGENERATION POTENTIAL

There are several post-modernization steam generating alternatives for Kaiser Steel. Alternative G (notation used in the Kaiser Engineer Report "Phase I Steam and Fuel Energy Study") represents 55 MWe of cogenerated power. The essence of the report can be summarized as follows:

Alternative A: Burn fuel oil in existing boilers to achieve steam requirements, and flare blast furnace gas (BFG).

Alternative B: Add additional low-pressure boilers, burning a combination of BFG and fuel oil to achieve steam requirements.

Alternative G: Add high-pressure boilers and steam turbines driving electric generators to produce a 55 MWe demand and meet steam requirements.

Alternative G would involve the use of two boilers rated at 500,000 lb/hr each. In addition, there would be two electric generators rated at 25-30 MWe each and an extraction turbine to convert the 1450 psi steam (saturated) to 175 psi steam for yard use. Alternately, the cogeneration system could have a condensing turbine in a closed-loop system. If Alternative G were implemented, Kaiser Steel's fuel costs would be reduced by \$24 million per year and result in a net fuel savings of the equivalent of 4,300 barrels per day (1.6 million barrels per year).

The estimated cost of Alternatives B and G (cogeneration) are \$12.6 million and \$63 million, respectively. The energy allocations and annual costs for the three alternatives are given in the following tables.

ENERGY ALLOCATION AT CAPACITY OPERATION
Equivalent Barrels of Fuel Oil per Day

| Alternative | BFG Available | BFG Used | Fuel Oil Used | Total Energy | |
|-------------|---------------|----------|---------------|--------------|-------|
| | | | | Available | Used |
| A | 7,800 | 0 | 5,600 | 13,400 | 5,600 |
| B | 7,800 | 5,200 | 900 | 8,700 | 6,100 |
| G | 7,800 | 7,200 | 1,300 | 9,100 | 8,500 |

| Annual Cost, \$ Millions | | | Total | Savings/Benefit over Alternate A \$ Millions |
|--------------------------|-------------|-----------|-------|---|
| Alter. | Incremental | | | |
| | Fuel Oil | Maint/Opr | | |
| A | 31 | 0 | 31 | -- |
| B | 5 | 0.5 | 5.5 | 25.5 |
| G | 7 | 2.0 | 9.0 | 22.0 plus value of electricity |

IV. ECONOMIC CONSIDERATIONS

Capital expenditures of domestic operations totaled \$87 million in 1976, compared with \$67.6 million in 1975. It is expected that 1977 domestic capital expenditures, including expenditures for refurbishing older facilities, the modernization and facilities roundout programs, and environmental control programs, will increase to approximately \$150 million.

The modernization program is being partially financed by the issuance of \$148 million first mortgage bonds due 1992. These bonds extend existing debt of \$72 million, including approximately \$24 million which would have been payable during the reconstruction period, and provide \$76 million in new money. Additional required funds are expected to come from internally generated cash, from an additional \$50 million borrowing which has not yet been arranged, and from the possible issuance of pollution control revenue bonds.

A short payback period (risk-modified) is required for any economic-based project at this time. This is particularly true for cogeneration projects, but it applies to other capital-intensive projects as well. The company uses a double declining balance (DDB) depreciation method over a 1-1/2-year period and then switches to a sum of the years digit (SYD) depreciation method for the remaining life of the equipment. Equipment is not depreciated on an individual basis but rather is depreciated as a class of equipment specified, in Kaiser's case, for equipment processing metals as the raw material.

V. ENVIRONMENTAL ISSUES

Overall, capital expenditures to minimize adverse environmental effects for the corporation's mining and steelmaking operations total approximately \$75 million. Environmental control maintenance and operating costs were approximately \$8 million in 1976 and \$7 million in 1975. Capital expenditures for environmental control purposes were \$10.4 million in 1976 and \$6 million in 1975. Partially in connection with its steelmaking modernization program, the corporation expects to spend an additional \$66 million, including \$27 million in 1977, on environmental control equipment over the next three years.

Energy conservation no longer has the number one priority at Kaiser. The environmental issues are so severe that major modifications and new equipment will be required to meet the regulatory standards. The modernization program is mainly concerned with new process equipment that will not only upgrade Kaiser's steelmaking efficiency but also provide energy conservation and environmental control.

Significant additional environmental control expenditures are to be expected as environmental regulations and enforcement policies become even more stringent. Various administrative and judicial proceedings concerning alleged violations of emissions regulations and a consent decree are pending.

The Kaiser-Fontana modernization program is to be completed in mid-1978 and, in addition, Kaiser expects to invest about \$100 million over the next five years in environmental control equipment.

VI. INSTITUTIONAL

Kaiser and SCE discussions about cogeneration over the past several years have been unproductive. Kaiser would like to consider the option of selling cogenerated power to an interested municipal utility, but this option would involve wheeling over SCE lines. Kaiser would also be willing to consider a mixed program in which they would supply the utility with blast furnace gas in exchange for steam and electricity. The utility would build the turbine/generator on Kaiser's land and Kaiser would purchase and own the boiler.

VII. TECHNICAL DATA

A. PROCESSING EQUIPMENT

Kaiser Steel's steelmaking facility at Fontana currently includes four blast furnaces, seven coke oven batteries, eight open-hearth furnaces, a three-furnace basic oxygen steelmaking shop, and various rolling mills and finishing facilities.

The plant is in the process of a major steelmaking modernization program. The modernization and expansion program at the Fontana steel mill, estimated to cost \$233 million, was begun in 1975. Design work is now about 90 percent complete, and 80 percent of the structural steelwork is in place. The program incorporates some features of a facilities roundout program begun in 1974.

Major elements of the modernization program are the construction of a two-furnace basic oxygen steelmaking shop to replace most of the existing open-hearth steelmaking operations, and the installation of a continuous slab-casting facility.

Basic oxygen process (BOP) steelmaking is more efficient and less costly than open-hearth steelmaking and is widely used throughout the domestic steel industry. In 1976, 54 percent of Kaiser Steel's raw steel production came from its existing basic oxygen shop, compared with an estimated domestic industry average of 62 percent. When the new basic oxygen shop reaches full operation - now expected in mid-1978 - virtually all of Kaiser Steel's raw steel production will be by the basic oxygen process. The No. 2 BOP shop will have an annual capacity of 2.3 million ingot tons, which, combined with the existing No. 1 BOP shop, will increase Fontana's annual capacity to 3.6 million tons. The new basic oxygen furnaces have been designed with the most modern and efficient pollution control equipment available.

The new continuous slab caster will process part of the output from the new basic oxygen process shop. The caster will permit a substantial increase in the production of high-quality grades of steel now used extensively in manufacturing large-diameter pipe, in two-piece cans and in constructing ships and offshore platforms.

In traditional steel processing, molten steel is teemed into ingot molds in which the steel is solidified. The ingot is reheated to attain uniform temperature and then rolled into slabs. In continuous casting, molten steel is poured into a water-cooled mold which forms the hardening steel into a continuous slab. The slab continues to solidify in a long casting machine and is automatically cut into desired lengths as it emerges from the caster. The caster and other elements of the modernization program, including modifications and improvements in the blast furnace area, are expected to be on-stream in mid-1978.

In order to determine the precise amount of by-product gases available, an extensive metering program has been initiated. Metering devices have been installed throughout the plant to record all major gas flows. Once this program is completed, plant engineers will have a much greater knowledge of their by-product fuel supply. They feel their energy conservation study cannot be completed without these data, which will not be available until next year.

B. PROCESS ENERGY PROFILE

1. Electrical Demand

Kaiser-Fontana has an average peak requirement of 116 MWe with a monthly usage of $55-60 \times 10^6$ kWh and spends on the order of \$1.5 million per month for electricity.

2. Steam Load

The plant's seven existing boilers are rated at an aggregate 640,000 lb/hr when using maximum blast furnace gas (a by-product fuel) and 950,000 lb/hr when using other fuels such as natural gas or fuel. At present, the by-product, low-Btu (85 Btu/ft³) blast furnace gas provides approximately 30 percent of the boiler fuel requirements. The gases, however, are not steady; they can fluctuate to peak flows only 15 minutes out of each hour. The vessel exit temperatures of the gases can be as high as 3,000°F. This gas is transported throughout the plant through a 72-inch-diameter pipe.

3. Fuel Use

The Fontana steel mill requires large amounts of electrical and thermal energy. At current production levels, about 75 percent of the mill's energy requirement is obtained from coal largely supplied from the corporation's mines. The balance is purchased from outside suppliers of natural gas, diesel and fuel oil, and electric power. Although fuel shortages have had a minimal effect on operations, cut-backs of petroleum (particularly diesel fuel), natural gas, or electricity over an extended period of time would have a significant impact on operations. Fontana currently has fuel oil storage capacities sufficient to allow approximately 35 days of operation during

periods of interruption in natural gas supplies. The cost of fuel oil used during periods of interruption has been substantially greater than the cost of natural gas. Natural gas is in short supply, and according to a forecast issued by the Southern California Gas Company in November 1976, most uses of natural gas at the Fontana steel mill will be fully curtailed by 1980 unless new natural gas supplies are brought into Southern California. Assuming capacity operation, the forecast gas curtailments could significantly increase operating costs. In addition, certain operations at the steel mill will have to be converted to alternate fuels by 1979. The capital costs of such conversions have not yet been determined but are expected to be substantial.

VIII. KEY PROBLEMS

The main problems with respect to cogeneration implementation are:

- (1) Kaiser's metering program is not complete; thus, the exact quantity of gas available to produce steam for cogeneration is unknown at this time.
- (2) Economics might favor selling the blast furnace gas rather than using it to produce steam for cogeneration.
- (3) Kaiser's concept of having a utility-owned (other than SCE) on-site cogeneration power plant would require wheeling of power.

APPENDIX A-7

COGENERATION SITE REPORT
ORGANIC AND INORGANIC CHEMICALS

KELCO COMPANY
SAN DIEGO PLANT

Participants

Kelco

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K. Peterson (telecon)

Jet Propulsion Laboratory

V. C. Moretti
M. L. Slonski

San Diego Gas and Electric

M. Hale
C. May

Utility: San Diego Gas and Electric Company (SDG&E)
Air Basin: San Diego
APCD: San Diego County
AQMA: San Diego

Address:

Kelco Company_____
Division of Merck and Company, Inc.
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San Diego, CA 92113
(714) 292-4900

This site report is based on notes taken by survey team members during visits to the plant, telephone conversations with plant personnel, and various reports furnished by the company. The report has been reviewed and approved by the company. The opinions, attitudes, and conclusions expressed in the report are those of the company and not necessarily those of the Jet Propulsion Laboratory.

I. GENERAL INFORMATION

The San Diego-based operation of the Kelco Company primarily consists of harvesting kelp from the Pacific Ocean and extracting algin through a proprietary process. Kelco also produces xanthan gum, a chemical substance developed through the company's research and development program. The two products are basically used as additives to food and industrial and pharmaceutical products.

The plant, located on 20 acres along the waterfront, employs 270 factory workers and an office staff of 100. Total plant worth is on the order of \$80 million. Kelco is one of the largest kelp harvesting and algin processing plants in the world. The international competitors are England, Germany, Norway, and Japan. The only competitor in California is Ocean Laboratories, which is a subsidiary of Stauffer Chemical Company located in Oxnard.

The plant is one of the top energy users in San Diego County. The San Diego Gas and Electric Company (SDG&E) supplies all its electricity.

Information sharing is not a common practice in this industry. However, within the San Diego industrial community, intense cooperation in energy conservation programs and energy saving ideas is practiced by means of monthly meetings of the largest companies, coordinated by the American Institute of Plant Engineers (AIPE). The local Chamber of Commerce is also very active in the energy and environmental concerns of large industries such as Kelco.

II. PLANT PROCESSING OPERATION

Kelp is harvested at sea in large ships and transported to the San Diego plant for shredding, drying, and processing into a fiber and a granular form ready for market.

With long-term kelp bed leases and new product development, the company feels its future is assured.

Xanthan gum is manufactured by a Kelco process that was under patent until about two years ago. There are now other competitors in this area, but Kelco has a tremendous technical and marketing lead. Since Xanthan gum is not a kelp derivative, the plant need not be located near the ocean. In fact, Kelco has constructed a multimillion-dollar xanthan gum plant in Oklahoma.

Kelco has three separate processing plants on site, designated as Plants A, B, and C. Plant A processes and dries the kelp, producing a granular algin. Plant B is similar to Plant A and produces a fiber algin. Plant C produces xanthan gum and is basically a fermentation, sterilization, and vaporizing process. Plant C utilizes approximately 60 percent of the total steam load and 55 percent of the total electric demand. The remainder is supplied to Plants A and B.

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III. COGENERATION POTENTIAL

At present Kelco has formulated four cogeneration concepts: Two with SDG&E, one internal, and one as a massive joint venture scheme with public and private participants.

SDG&E has a peaking power plant directly across the street from Kelco, and negotiations were initiated with Kelco for the sale of steam and electricity, resulting in Plans I and II.

Plan I

The SDG&E steam turbine peaking power plant would bleed off steam at 1,250 psig, 950°F, during nonpeaking times when this steam is available for selling purposes. Feedwater separation is necessary, so a heat exchanger would be installed giving Kelco steam at 180 psig, 373°F (saturation). This would insure SDG&E that their feedwater would not be contaminated by back flow from Kelco's process steam. The low-grade steam would then be piped across the street for Kelco's operation.

SDG&E steam price to Kelco was about \$4 to \$5 per 1,000 pounds of steam. The estimated amount of steam in which Kelco is interested ranged from 130,000 to 200,000 lb/hr, which would reduce the power plant output capacity from 16,000 to 25,000 kW, based on a steam-to-power ratio of 8 pounds per kW.

The critical issue with the concept is that Kelco could not be guaranteed a steady supply of steam. From the past two years, SDG&E's plant peaked one or two days per year at most; however, future projections are uncertain, and it is SDG&E's opinion that the peaking occurrence will increase with time. Kelco agrees with that opinion and is not interested in pursuing the project.

Plan II

The second concept consists of the installation of 20 to 24 MW_e gas turbine/generator set, on Kelco's property, with a large waste heat boiler (100,000 to 150,000 lb/hr, 125 psig, saturated steam output); all equipment would be owned and operated by SDG&E. In this scheme, Kelco would provide all minor equipment and piping for connection to their process. Kelco would then phase out their existing boilers and purchase steam from SDG&E.

No formal SDG&E/Kelco agreements were made, and ultimately the project was deemed economically unsound by Kelco because the purchase price for the steam was too high.

Plan III

Kelco has also considered a wholly owned cogeneration system which would be located on its site. Its existing boilers would be upgraded to produce steam at 250 psig, saturated. The steam would drive a

turbine connected to a generator which would supply 2.0 MWe of electricity for the plant's operation. No excess by-product electricity would be available, requiring Kelco to remain tied to SDG&E's grid for standby and supplemental power. The turbine's outlet steam (100 psig, saturated, 150,000 to 160,000 lb/hr) would be utilized as process steam for the algin and xanthan gum operations. All on-site cogeneration equipment would be owned, operated, and maintained by Kelco.

It was determined by Kelco that this concept would not meet a payback period of less than three years, which is the requirement for this type of project, and thus would not be economically feasible at this time. They are still considering the plan, and it could be activated if their self-produced electricity ever becomes less costly than that which they purchase from SDG&E.

Plan IV

Kelco's parent company, Merck and Company, Inc., is involved in a major study with the County of San Diego, City of San Diego, SDG&E, and Teledyne National Corporation in a \$25 to \$30 million rubbish collection plant for the San Diego County area. Merck, along with its Kelco Division, has been working on this project for over two years, and construction could start within one year.

The plant would separate solid waste and process it into refuse-derived fuel (RDF), consisting mainly of shredded paper. The by-products of scrap steel, aluminum, and glass would also be salvaged. The RDF would be transported to the Kelco plant and used as an alternate fuel to fire the boilers, supplementing the natural gas and fuel oil they now use.

At the Kelco-plant, a cogeneration system would be installed capable of producing 12 to 13 MWe of electricity and ample steam to meet the plant's steam load. The refuse fuel would fire special boilers, producing superheated steam at 750 psig and 750°F. Three steam turbines (one large and two small) would be used with a steam outlet of 100 to 125 psig in the saturated state. This would be utilized as process steam for the Kelco plant.

Of the 12 to 13 MWe of produced electricity, 6 MWe would be used on site for Kelco's operations. The rubbish collection and processing plant (producer of RDG) would require 5 MWe, which would be supplied by the Kelco cogeneration power plant and "wheeled" over SDG&E's transmission lines. If wheeling is not acceptable to SDG&E, Kelco would construct its own transmission system. The remaining surplus power, approximately 2 MWe, would be offered to SDG&E.

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IV. ECONOMICS CONSIDERATIONS

Kelco has a very strict investment criteria with a one-year pay-back period for most major capital investments. This can vary up to four years, depending on the circumstances. They use a 10- to 15-year straight line depreciation method for tax purposes.

Due to the nature of the process, there is extensive corrosion of the equipment, with equipment life ranging from 20 years to as short as 3 to 4 years. Continuous maintenance, overhaul, and updating is made to the equipment. It is not likely that premature equipment phasing out will occur for the replacement of new equipment.

No major studies have been performed to try to conserve energy. Kelco anticipates the cost for fuel oil and natural gas to increase by 10 percent per year. Electricity is expected to increase 1 ¢/kWh next year, and they anticipate a 75 percent gas curtailment.

V. ENVIRONMENTAL

The San Diego County Air Pollution Control District has a major impact on the Kelco operation. Kelco has submitted a 1,500-page report to the San Diego County APCD identifying all its air pollution sources. Kelco also deals with the ARB, EPA, agencies concerned with water, State Health Department, and the State Coastal Commission. Environmental control is a concern, and new pollution control equipment is installed as needed.

VI. INSTITUTIONAL ISSUES

The San Diego Gas and Electric Company (SDG&E) provides natural gas and electricity to meet all of the Kelco plant's needs. The SDG&E peaking power generating plant located directly across the street lends itself to cogeneration with the sale of steam to Kelco.

In order for Kelco to enter into a cogeneration agreement, the price of steam will have to be reduced. SDG&E/Kelco contractual negotiations have not been initiated; however, joint studies have been performed and a cooperative spirit exists between the two parties.

SDG&E is seeking approval to charge industry peak rates currently with the power plant's peaking in order to discourage electric usage at that time. This is not practical for around-the-clock all-year operational plants. Utility peaking can be predicted by monitoring, and Kelco may be required to shut down some of its major electric equipment during peaking periods.

Positive incentives that would provide reasonable payback periods are welcomed, including any type of financial incentive (tax credit, investment subsidy, depreciation schedule).

Interindustrial communication, cooperation, and information sharing exists in the San Diego business community. The company is a stable organization and maintains a sharp awareness of innovative ideas and advanced technology.

VII. TECHNICAL DATA

A. PROCESS EQUIPMENT

Six existing boilers are clustered on site. Four water tube-type boilers are the primary boilers and are in continuous service, one fire tube-type is rarely used, and one very small boiler (7-1/2 HP, 200 psi) is operational. The company is in the process of installing an economizer on the boiler stack to recuperate heat.

The two algin processing plants will most likely have no major process changes, and the steam load would be affected only by increased production.

The xanthan gum operation is under continuous research, and new methods that will change the process and steam requirements are possible.

B. PROCESS ENERGY PROFILE

1. Electric Demand

The plant operates continuously 24 hours per day, 365 days per year, with a steady electric load and only slight daily and annual base load variations except for equipment failures or maintenance shutdowns. Thus, their base load is the same as their peak load except when they have equipment start-up.

| | Hourly | Daily | Monthly | Annually |
|--|--------|---------|---------|----------|
| Plant's electrical usage | kW | kWh/day | MWh/mo | MWh/yr |
| Base and peak load | 6000 | 144,000 | 4,380 | 52,560 |
| Distribution: Plant A and B = 45%; Plant C = 55% | | | | |

The plant's electricity rate is 3-1/2 ¢/kWh with an annual cost on the order of \$1.7 million.

2. Steam Load

At present the total plant steam load is 130,000 lb/hr (120 psig, 350°F), with Plant C utilizing 60 percent and 40 percent going to Plant A and Plant B. The load is steady every day all year round with only slight variations. All steam is produced by the five existing boilers burning primarily natural gas with diesel fuel as backup.

The plant is in the process of a two- to three-year expansion program which will require an ultimate steam load of 200,000 lb/hr at 180 psig and 380°F.

3. Fuel Use

The plant's natural gas cost is approximately \$2.30/MBtu with a \$1.5 million annual gas bill. They anticipate paying \$3/MBtu by the end of the year, with a 10 percent annual increase thereafter.

In 1976, Kelco was curtailed of gas for 31 days, and used diesel fuel (No. 2 oil) for backup. The SDG&E forecast implies Kelco will burn oil 75 percent of the time in the future; however, in the past SDG&E has overestimated the severity of the winter climate and more natural gas has been available to industry than expected. Fuel oil consumption has been minimal and the cost slightly more than natural gas, but the reverse is expected by the end of 1977.

When transferring to oil from gas, three to four hours' notice is provided and there is minimum process disruption. They are presently negotiating with Arco for an oil line to the plant in anticipation of future gas curtailment.

VIII. KEY PROBLEM AREAS

The major problem areas with respect to cogeneration implementation are as follows:

- (1) Purchase price for steam and assurance of a continuous steam supply from SDG&E.
- (2) Excessive capital expenditures for air pollution and water quality control equipment.

APPENDIX A-8

COGENERATION SITE REPORT
GLASS CONTAINER INDUSTRY

OWENS-ILLINOIS, INC.
Oakland Glass Container Plant

Participants

Owens-Illinois

Jet Propulsion Laboratory

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This site report is based on notes taken by survey team members during visits to the plant, telephone conversations with plant personnel, and various reports furnished by the company. The report has been reviewed and approved by the company. The opinions, attitudes, and conclusions expressed in the report are those of the company and not necessarily those of the Jet Propulsion Laboratory.

I. GENERAL INFORMATION

Owens-Illinois (O-I), Inc., headquartered in Toledo, Ohio, is a worldwide manufacturing organization for packaging products. There are 23 O-I glass container plants in the nation; three of these are in California. O-I, the largest in the industry, produces 23% of the total national production, and feels that they are the most technologically innovative.

The O-I glass container plant in Oakland produces approximately 750-1000 tons per day, and a maximum 320,000 tons per year of glass container products. They have five furnaces, employ 1800 employees, and operate on approximately 32 acres of land. In addition to the glass container operation, there is a corrugated paper facility which provides shipping containers for those product and for marketing purposes. Although the corrugation plant is a separate process, the glass container and corrugated paper operations are operated as one plant.

The industry's primary trade association is the Glass Packaging Institute (GPI) in Washington, D. C. O-I feels that the glass container industry is one which views the future with innovation and advanced technology to make a better product, modernize their product line, conserve energy, and comply with the environmental laws. Industrial communication, cooperation, and information-sharing is prominent within the industry in the noncompetitive area. However, when information relative to the process and/or profits is evident, there is very tight control on information-sharing.

II. PLANT PROCESSING OPERATION

The manufacturing of glass containers is a very intense heat process and large quantities of thermal energy are required. Of the leading thermal energy industrial users, the glass industry ranks approximately seventh. The basic process is to mix a batch of raw materials and melt it in a furnace to generate molten glass. The glass is then transported to molds where the containers are formed. From there on, it is a matter of cooling the bottles in a controlled manner so as to meet the quality control tests. Shockproofing, labeling, and packaging then follows. The major process steps and the percentage of energy required as a function of Btu per ton of product is shown below:

| <u>Major Process Steps</u> | <u>Percentage of Total Btu/Ton</u> |
|---|------------------------------------|
| Batch handling and cullet (scrap glass) crushing | 0.66 |
| Melting (use of furnaces) and refining (removal of gaseous inclusions) | 64.47 |
| Conditioning and delivery | 13.92 |
| Forming | 5.03 |
| Post-forming (annealing, decorating, etc.) | 9.32 |
| Product handling | 2.18 |
| Space conditioning | 4.42 |
| | <u>100.00</u> |

The major raw materials used to make container glass are sand, soda ash, limestone, and feldspar. Minor ingredients are also used as required to adjust color and melting characteristics. These materials are weighed into the proper portions, mixed, and fed into a furnace along with cullet (scrap glass) which has traditionally constituted 15 to 20 percent, by weight, of the total batch. In the furnace (see Figure 1) the raw materials and cullet react and produce molten glass with temperatures reaching from 2700°F to 2800°F. This occurs in the first one-third to one-half of the melting chamber; the remainder of the melting chamber is used to remove most of the gaseous inclusions that form during the melting stages. After passing through a submerged, refractory throat, the glass enters a conditioning chamber in which it is cooled to a uniform temperature (approximately 2300°F), and the remaining small, gaseous inclusions are dissolved. From the conditioning chamber, the glass flows into and through shallow channels called forehearth that uniformly cool the glass to the proper temperature (2000°F to 2100°F) for forming. To properly accomplish this task, the forehearth must simultaneously heat the glass flowing near the sides of the channel and cool the glass flowing in the middle of the channel. The glass is then cut and dropped to forming machines where the glass temperature decreases from 2000°F to 1400°F within a matter of seconds. The formed containers are then conveyed to the lehrs where the annealing process takes place. These are long chambers where the glass is cooled under controlled conditions to 100°F to 150°F, and surface treated for breakage durability and scratch resistance. The glass containers are then inspected, labeled, and packaged for shipment.

The melting units primarily in use in the glass container industry are regenerative furnaces in which fuel is fired from either end-ports or side-ports. In the end-port configuration, the flame and combustion products travel in a horizontal U-shaped path across the surface of the glass within the melter. Fuel and air mix and ignite at one port and discharge through a second port on the same end-wall of the furnace. In the larger side-port furnaces, used by the Oakland plant, the fuel and air mix and burn on one side of the tank while the products of combustion are withdrawn from the other side, as Figure 1 shows.

To conserve fuel, a regenerative firing system is used which employs dual chambers partially filled with brick checkerwork. As the spent products of combustion from the melter pass through and heat one checkerwork system, incoming combustion air is preheated while passing through the opposite regenerator. The direction of the cross-firing and, thus, functions of each regenerator, are interchanged periodically with reversals occurring approximately every 20 to 30 minutes. These regenerators are approximately two stories tall and are positioned on each side of side-port furnaces. The combustion air is heated as it passes through the hot bricks to approximately 2450°F. On the exhaust or wasting side, the temperature of the exhaust furnace gas entering the top of the brick regenerator is on the order of 2850°F; at the bottom it is 1350°F. By the time the exhaust gas is drawn to the bottom of the stack by mechanical exhausters it is slightly above atmospheric pressure at 1000°F. The flow rate of this gas varies sporadically, but on the average it is approximately 15,000 standard cubic feet per minute for each of the five O-I furnaces.

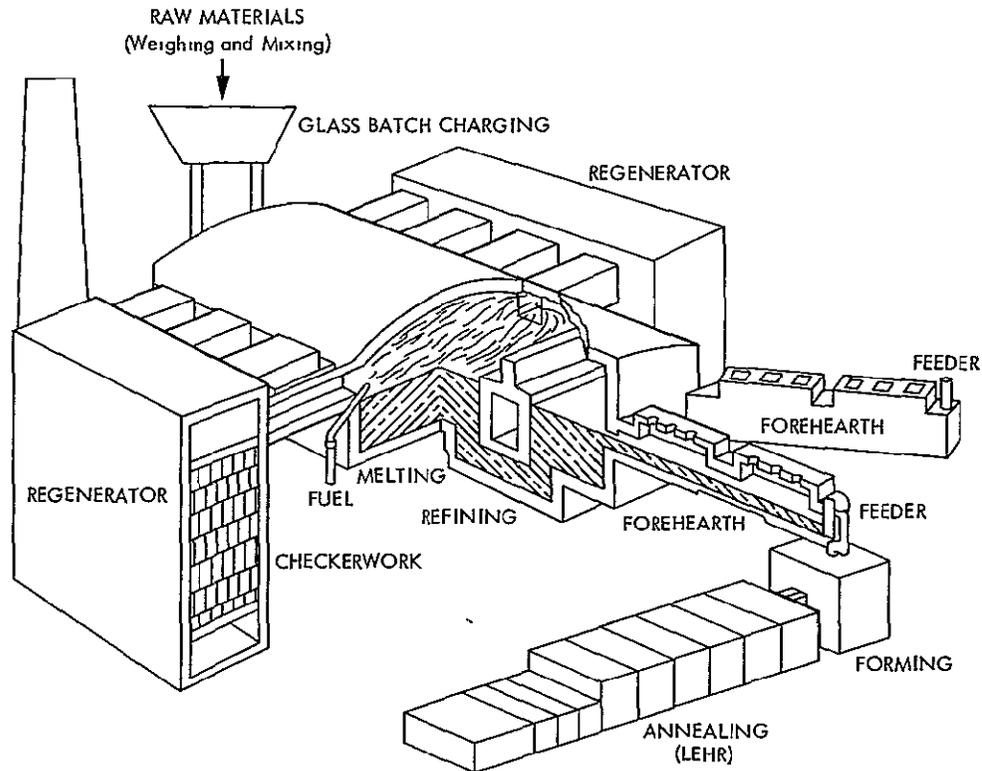


Figure 1. Sketch of a Side-Port Regenerative-Melting Furnace

III. COGENERATION POTENTIAL

The O-I corporate office is presently investigating two concepts for cogeneration. The first concept is to run the 1000°F stack gas through a high pressure (850 psig) waste heat boiler (one boiler for each furnace) to drive a steam turbine. The shaft horsepower would be utilized either for electrical generation or mechanical work, with the exhaust steam being piped to O-I's corrugated paper process. During periods when the corrugated paper plant is not in operation, the steam would be dumped. The main problem with this system is that the exhaust steam from the furnace is contaminated with glass particles and the boiler types of today are easily plugged. New technology is required before this concept is applicable. O-I anticipates that new waste heat boilers that will work for them are at least two years away.

The second concept is to drive a gas turbine with the 1000°F stack gas to generate electrical power or shaft work. Again, the main problem

is that the stack gas is too dirty and would destroy the turbine blades with rapid corrosive wear. One of the drawbacks of this system is the low pressure of the exhaust gas stream (slightly above atmospheric); the inlet pressure to the turbine would have to be boosted or the outlet pressure would have to be at a vacuum condition.

These concepts are presently in the study stage, and O-I is working on the technical details at the corporate level. Economics is the main criteria used for final determination and, at this time, the economic analysis is only preliminary. All numerical and engineering design details are proprietary. It was the general consensus of the O-I attendees that cogeneration for the Oakland plant will not be implemented because of the technical problems and the economics.

IV. ECONOMIC CONSIDERATIONS

The basic requirement for successful cogeneration implementation with O-I's Oakland plant is economics. There are two basic types of capital investments at O-I, a profit maintainability investment and a profit improvement investment. The corporate headquarters makes all financial decisions and the expenditure proposals are reviewed through the chain-of-command, which starts at the plant (expenditures of \$5000 or less do not need corporate approval), then goes to the regional level, to the division level and, finally, to the corporate headquarters. O-I corporate management maintains a 1-year and a 5-year capital investment plan. Like most industries, they feel that regulatory uncertainties (mainly in the environmental area) and rapidly rising fuel costs make it impossible to plan for more than five years. For financial reporting purposes, depreciation and amortization are determined on the straight-line method. For income tax purposes, accelerated methods are used for a substantial portion of the assets.

Some of the cogeneration incentives discussed were tax write-offs, investment credits, sales tax exemption, new cogeneration asset class (exemption from corporate taxes), and low interest long term financing (similar to industrial development bonding for air pollution control and water quality control).

V. ENVIRONMENTAL ISSUES

The Oakland plant now operates under compliance with all air pollution laws. With the burning of natural gas in their furnaces, air pollution is not a major problem. If they burn low sulfur fuel oils, then the SO₂ regulations can be met. In fact, they just installed a \$300,000 baghouse about three months ago, utilizing their own patented design to control emissions from a hot end treatment system.

A critical potential problem they foresee is New Source Review Rules being applied due to the addition of a waste heat boiler to capture waste heat from the stack gas stream. If these rules apply to this modification then, even though no additional emissions are being

generated, it would constitute an undue hardship and may well negate the construction of this energy saving technique.

VI. INSTITUTIONAL ISSUES

The Oakland plant's management believes that their relationship with PG&E is good. O-I has not approached PG&E on issues related to cogeneration. In most of their process, natural gas is the primary fuel supply. When natural gas becomes more and more curtailed, the backup fuels will play a larger role in plant operation. For the glass container industry, propane is a backup fuel for various parts of the process. If propane becomes in short supply during natural gas curtailment, the entire process could be shut down. This could be a major problem to the glass container industry.

One major incentive is the perceived exemption from the new source regulations for this proposed bottoming cycle system. It is O-I's opinion that the industrial community should not come under New Source Review regulations for any proposed heat saving device or system which requires no additional fuel.

VII. TECHNICAL DATA

A. PROCESSING EQUIPMENT

The primary equipment in the O-I plant is the five large furnaces and the eight air compressors (seven reciprocating and one centrifugal) to drive the forming machines, fans, loading devices, and unloading devices. O-I has a diesel engine which is used for backup power to drive four to five fans that generate cooling wind to the furnace. In case of a power outage, the furnaces must be continuously cooled or they will rupture, causing a major spill within the plant.

The furnace size is rated as 100% capacity by the production ratio of one ton of glass per five square feet of melting surface. O-I's furnaces range from 600 to 1200 sq ft each. Within the industry these are considered average size furnaces. A furnace is rebuilt every 5 to 6 years and is modified with new advancements in furnace design. Also, most of the product line machines that are dependent upon the furnace are rebuilt and overhauled. Machinery replacement cost is very high because of the high process temperatures.

The plant operates 320 days per year but the molten glass never stops flowing. There is a 5-8 man furnace maintenance crew that is continuously plugging small leaks and making "hot" repairs. During nonoperating periods the glass is on a low flow and is recycled back into the furnace. This procedure is necessary in order to prevent hardening within the furnace.

The Oakland O-I glass container plant is unique in that it also has a corrugated paper plant as part of the operation. This plant uses a small amount of steam and is supplied by a package boiler, which is eight years old and runs on natural gas only. There are plans to replace this boiler with a dual fuel capacity (natural gas and oil) boiler for about \$100,000.

Plans for plant modernization are continuous; however, plans for expansion are limited because of the lack of space.

B. PROCESS ENERGY PROFILE

1. Electricity Demand

The total annual electric usage in 1976 was on the order of 90×10^6 kWh. For a typical operating 24-hour period this load does not fluctuate and runs very close to maximum. Their 1976 peak was 13.9 MWe at an average cost of 2.077 ¢/kWh. The cost of electricity as of June 1977 was 3.365¢/kWh, a 62% increase.

2. Steam Load

The glass plant has no steam load. There is a small load of 10,000 to 11,000 lb/hr, 200 psig, saturated steam for the corrugated paper operation. The plant operates on two shifts, five days per week, thus there is no need for steam around the clock. When the corrugated paper process is not in operation, the boiler is idle.

3. Fuel Usage

The primary fuel used is natural gas and is supplied by PG&E. At present they are on a P3 curtailment for the furnace and boiler and a P2 for the lehrs and forehearth. In 1976 they used 2.62×10^9 CF at a cost of \$1.86/MCF; as of June 1977 the cost was \$2.28/MCF, a 23% increase.

Other fuels are used on a standby basis. Distillate oil No. 2 is purchased from Exxon, and is stored in their 1-1/2 million gallon fuel oil storage tank complex, which is shared with other O-I plants in California. In 1976, they used 104,578 gallons at an average price of 37¢ per gallon. In 1977 they are paying 40¢ per gallon. Propane is also used as a standby fuel during gas curtailment and is purchased from local brokers. In 1976 they used 61,405 gallons at a cost of 31.7¢ per gallon. So far in 1977 they have not used any propane.

The Oakland plant sustained a gas curtailment for a total of five days in 1976. Each occurrence was for a period of one to two days, and they were given 24 hours to convert over to oil. In this industry, converting from natural gas to oil is difficult. The natural gas burner must be replaced with an oil firing burner; this is a completely different type of system and must be installed each time before use. Startup can cause air pollution problems and great care must be exercised not to damage the furnace. In addition, more energy per ton of product is required when oil is used instead of natural gas.

The primary energy source for the batch and cullet-handling, forming, and product-handling steps is electricity. The melting and refining step utilizes natural gas as a primary fuel with distillate fuel oil No. 2 as a backup. The primary fuel for the conditioning and delivery, and post-forming operations is also natural gas. Fuel oils are generally not used in these steps because they often cause significant quality problems. Natural gas, electricity, and propane are used in the post-forming operations of annealing and decorating with natural gas being the preferred fuel. In the forming operations, electricity is used indirectly to produce compressed air, which drives the forming machines, and directly to drive timing and loading and unloading devices.

VIII. KEY PROBLEM AREAS

The basic problem areas with respect to cogeneration implementation at the O-I Oakland plant are as follows:

- (1) At present, waste heat boilers are not capable of taking contaminated stack gas.
- (2) Advanced technology is required for gas turbines to accept the stack gas which is contaminated with glass particles.
- (3) Lack of a stable policy for the many environmental regulations, enabling industry to perform advance planning (plans for at least five years are desirable).
- (4) New source standards as they may be applied to waste heat recovery or bottoming cycle cogeneration projects.

APPENDIX A-9

COGENERATION SITE REPORT
PULP AND PAPER INDUSTRY

SIMPSON PAPER COMPANY

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Air Basin: Sacramento Valley
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This site report is based on notes taken by survey team members during visits to the plant, telephone conversations with plant personnel, and various reports furnished by the company. The report has been reviewed and approved by the company. The opinions, attitudes, and conclusions expressed in the report are those of the company and not necessarily those of the Jet Propulsion Laboratory.

I. GENERAL INFORMATION

The Simpson Paper Company is a subsidiary of Simpson Timber Company with headquarters in Seattle, Washington. The plant, located in Anderson, just south of Redding, California, is an integrated pulp and paper plant. The pulp is made from wood chips that are purchased from outside sources; 90% of the manufactured pulp is used in the plant's paper machines and 10% is sold on the market. The paper products produced are coated and uncoated fine paper, printing and writing grades. The primary market area is the 11 western states; California accounts for over half of total sales.

The Technical Association of the Pulp and Paper Industry (TAPPI) is the trade organization which provides technical information used throughout the industry. Three monthly trade journals are Pulp and Paper, Paper Trade Journal, and Paper Age.

The Anderson plant consists of two operations: (1) The pulp operation, which produces about 170-175 tons/day and is one of the smallest pulp operations in North America, and (2) the paper operation which produces about 400 tons/day and is one of the largest fine paper operations on the west coast. Competitors in the pulp industry are Fiberboard, Crown-Simpson, Louisiana Pacific, and Simpson Paper (Simpson Paper is the smallest). In the paper industry the competitors for fine grade paper are Champion (Pasadena, Texas), Consolidated Paper, Boise Cascade, Crown-Zellerbach, Northwest Paper, and Simpson Paper (Simpson Paper is the smallest producer). The plant employs a total of 410 union workers and 120 salaried employees.

Crown-Zellerbach Company is considered to be an innovative leader in the industry with respect to energy conservation. In the environmental area, Simpson Paper is one of the leaders in the industry. In particular, Simpson Paper has been especially innovative in the area of water and air quality control to meet Federal and State standards.

II. PLANT PROCESSING OPERATION

For the pulp process, wood chips are cooked in a digester which uses sodium hydroxide to break down the chips into fibers. The pulp goes through a series of screens and filters to remove residue; the clean pulp is then bleached to make it white. At this point the pulp can go directly into storage tanks as sludge pulp for direct processing into paper, or it can be dried and baled into 400-lb bales.

A residue, called black liquor, remains after the digester process. The black liquor contains hydrocarbon chemicals which are recovered and burned in the boilers as supplemental fuel that produces steam sufficient to operate the pulp mill, about 128,000 lb/hr depending on the level of production. In addition, sodium salts bottom-out and are recovered to be made into sodium hydroxide for reuse.

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For the paper process, pulp is in a slush form which goes through a series of refiners, where the fibers are cut to the proper size. This process is a high energy user with two refineries at 1000 hp and two refineries at 400 hp. The cut fibers proceed to cleaners that remove sand and dirt, and on to a paper machine which is a moving wire, where the pulp is pressed to remove water, dried, and then wound into rolls of machine finished paper.

The paper is produced for a selected market and often a coated finish is required. Coated papers go through an additional process where the coating is applied and shined before it is wound into rolls or cut into sheets.

Throughout the papermaking process there are pumps and drivers that use steam or electrical energy.

III. COGENERATION POTENTIAL

Two alternative plans for the installation of a cogeneration capability have been developed. Each is based on the same central concept, the primary difference being the amount of electricity generated and its distribution.

The basic cogeneration concept calls for the installation of boilers which will burn both hog fuel and coal. The boilers would have the capability to burn either type of fuel, or any combination of the two. The steam would drive a condensing extraction turbine generator which would generate the electricity. Hog fuel is a waste product of the lumber industry and is in plentiful supply. Presently, the cost is \$3 to 4/ton, bone dry, but it may go up to \$14 to \$17/dry ton as the demand increases.—Hog fuel is rated at 8800 Btu/lb, bone dry. The efficiency of burning hog fuel, however, is about 60% because the fuel usually contains 50% moisture.

The coal supply would come from Utah and has a very low sulfur content. Simpson Paper has discussed the supply of coal with the Coastal States Energy Company which owns the mine. The mine can furnish more than two million tons of coal per year. If the boiler were to burn only coal, the requirement would be about 200,000 to 300,000 tons/yr. The delivered price for the coal is \$32/ton and it is rated at 10,000-11,000 Btu/lb. The efficiency of burning coal is about 78%.

Option 1 would utilize a boiler rated at 300,000 lb/hr, generating steam at 850 psig and 900°F, and a condensing extraction steam turbine rated at 19 MWe peak capacity. Steam extraction would be at 175°F and 75 psig, to be used in the process. The steam turbine efficiency (including the generator and gear box) is rated at 80% but would fall to 73.6% when corrected for the extraction.

All power generated would be utilized by Simpson Paper. The equipment would be installed on the company's property next to the recovery boiler. The installation would require about 200 sq ft plus

space for fuel storage and equipment to handle the fuel. Once approved, installation would take about 2-1/2 years at a total cost of about \$24 million. No interruption in the plant operation would occur.

Option 2 would utilize equipment similar to that in Option 1 with a boiler rated at 400,000 lb/hr to generate about 22.5 MWe. The basic concept is essentially the same as Option 1 except that the steam and electricity would be used by both Simpson Paper and a nearby lumber producer. With this option, Simpson Paper would take approximately 75% of the power and steam produced.

At present, Simpson Paper believes the only feasible arrangement to accomplish this cogeneration option is to set up a new organization or company to own and operate the cogeneration plant on leased property. Both parties would purchase power and steam from the new company. This arrangement is deemed necessary because a company that sells power is considered a utility; neither party wants to be regulated as a utility. The installation of this option would take about 2-1/2 years at a total cost of about \$26.8 million. This time frame does not include obtaining environmental studies and permits, which could extend the time to about 6 years and increase costs substantially, impairing the economic feasibility of the project. The cost would be divided between the two companies on the basis of prorated energy usage. No price has been formulated with respect to the purchase of electricity from a third party. PG&E is interested in becoming the third party, but only if they can be guaranteed a constant supply of electricity.

IV. ECONOMIC CONSIDERATIONS

The Simpson Paper Company uses a discounted cash flow, return on investment analysis to evaluate capital investment projects. A project is usually expected to have at least a 22-25% pre-tax return. In some cases, however, a lower return may be accepted; for example, just because of the uncertainties with respect to future energy supplies and costs, a lower rate of return may be accepted for energy related projects.

Financing for a project of the magnitude of the proposed Option 1 cogeneration project (approximately \$24 million) would probably be a combination of external and internal financing.

The company uses accelerated depreciation methods for tax purposes. Life matching or prematurely phasing out old, useful equipment will not present a problem to the installation of cogeneration. The only items affected would be the three package boilers, and it is not definite that they would have to be phased out.

The company has a three-phase energy conservation program, each phase increasing the size of investment and complexity of the project as outlined below:

- I. Energy savings accomplished with no capital investment.
- II. Energy savings accomplished with small capital investment in the range of \$1,000 to \$20,000.
- III. Energy savings accomplished with a large capital investment, above \$20,000.

The company can achieve a 7 to 10% savings from phase I, and up to an additional 12% savings from phase II projects. A cogeneration program would be classified as a phase III project.

With respect to future expectations, the company believes the electricity rate will increase by 40% in the next five years. That expectation does not include any increase in taxes which are included in President Carter's energy plan. In addition, the company expects a 100% curtailment on natural gas in the next five years. Purchasing fuel oils is not expected to be a problem but they may have to expand their storage facilities.

The company suggested that one incentive would be help from the state in the form of tax-exempt financing. They feel a financing program similar to the one for environmental equipment would definitely be beneficial to the status of cogeneration. Other incentives that would help considerably are additional investment tax credits, an accelerated depreciation schedule, and exemption from property tax assessments of cogeneration facilities.

V. ENVIRONMENTAL ISSUES

The environmental issues are a major concern with respect to the proposed cogeneration project. It is estimated that approximately 25% of the total cost of the cogeneration project will be for complying with environmental regulations.

Requirements with respect to the sulfur content of coal are the biggest concern. The company would prefer that the requirements focus on actual emissions rather than on the sulfur content before the fuel is burned. The cogeneration plan calls for the burning of hog fuel mixed with coal. A typical mix will be about 95% hog fuel and 5% coal. Thus, the sulfur emissions will be averaged for the two fuels resulting in a cleaner environment with respect to air pollution than if only coal were burned. The company believes it should not be required to burn a fuel with a specified sulfur content when it is not necessary to do so because of the low emissions output.

The New Source Review Rules may or may not be a problem depending on the fuel mix that is burned. If only hog fuel is burned there is no problem with sulfur emissions; however, particulates may be a problem requiring the installation of bag houses. Today hog fuel is a waste product that is buried in open fields; this is a disposal method which is energy wasteful and environmentally objectionable. The utilization of hog fuel as an energy source for cogeneration will greatly reduce the problem. If only coal is burned a precipitator will be required. Also, the Shasta County area may be designated as a Class I buffer area

resulting in more stringent sulfur and particulate requirements. In addition, there is the possibility that an Air Diffusion Modeling study, costing \$50,000, will also be required to determine the effects of emissions on the air basin.

The environmental requirements are probably the biggest and most important factors that will work against the implementation of cogeneration. A serious problem is the fact that at the present time there is a great deal of uncertainty in this area. Without predictability in this area, the company is in a quandary and does not want to commit to a capital expenditure program. Predictability of the environmental requirements is necessary to evaluate the effect on the economics of the project. Without this, no decision on cogeneration can be made.

VI. INSTITUTIONAL ISSUES

Simpson Paper Company has had some contact with PG&E concerning the cogeneration project. The utility has indicated they would be interested in any surplus power that would be available. If the amount is below 3000 kW they will pay about 14 mills/kWh; if the amount is greater than 3000 kW special rates will be negotiated. The charge for a stand-by service connection would be about \$1/kW per month.

Simpson Paper is the largest customer of PG&E in the area. At one time the utility did not want to lose customers, especially large ones, but now the utility doesn't have any excess capacity in the area and their attitude has changed. There is some problem with communications between the company and the utility in that it is difficult for the company to get a timely response from the utility.

Cooperation from the local air agency and the Air Resources Board would be helpful. The requirement for an Air Diffusion Modeling study seems to be redundant since similar studies have been performed in the past.

VII. TECHNICAL DATA

A. PROCESSING EQUIPMENT

The following is a table depicting the types and operational characteristics of the equipment used in the process.

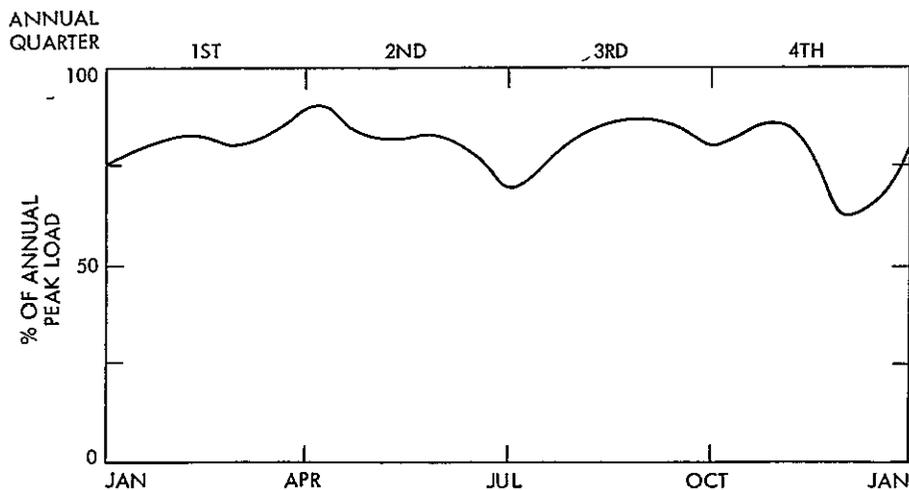
| Type | Size Max Cap. | Age, yr | Type of Energy Used | Duty Cycle S = Steady V = Variable | Maintenance Schedule | Location (cluster vs. scattered) |
|--|--|----------------|--|--|-------------------------|--|
| Package Boilers 1 2 3 | 74,000 lb/hr 74,000 lb/hr 74,000 lb/hr | 13 13 10 | } Natural gas, No 6 fuel oil as backup | } V | } 3 times per year | } C |
| Recovery boiler | 142,000 lb/hr | 2 | | | | |
| Furnances (total of 4) Economizers (total of 4) Dryers | Small | | Natural gas | S | | } S |

The company has a standard preventive maintenance program with a 68-man crew. As much as 20-25% of their time is spent on heat-related equipment.

B. PROCESS ENERGY PROFILE

1. Electricity Demand

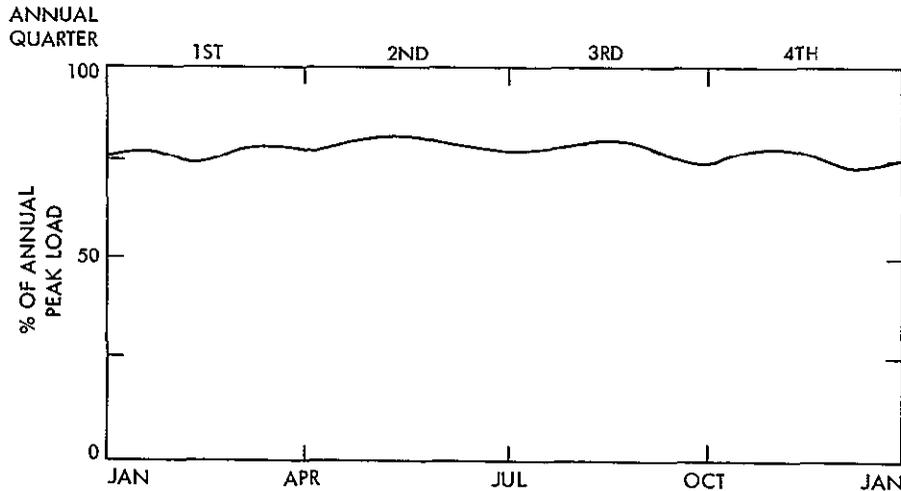
The paper plant has a peak demand on 19 MW and an average demand of 17 MW. The average usage is 12×10^6 kWh/mo at an average rate of 4.1 kWh. The plant operates on a continuous basis 350 days/yr. There is little variation in the electrical daily load. The annual load variation is depicted in the following graph:



The company is on a time-of-day rate structure and about 70% of Simpson's electricity bill consists of demand and adjustment charges.

2. Steam Load

The average daily steam load is 200,000-240,000 lb/hr. The three package boilers operate at 600 psig and 600°F, and are supplemental to the recovery boiler which operates at 600 psig and 750°F. The annual steam load variation is depicted in the following graph:



3. Fuel Use

Simpson Paper Company normally burns natural gas. Most of their gas is used in boilers and has a priority of P4; however, some, used in their dryers, has a priority of P2. Little gas curtailment (14 days in January 1977) has been experienced during the past year. The plant uses about 1.2×10^5 MBtu/mo of natural gas at \$2.29/MBtu, up 69% from a year ago.

For backup to the natural gas, the plant uses low (less than 0.3%) sulfur fuel oil. They have two storage tanks with a capacity of 250,000 gallons. The price for fuel oil is \$11.70/barrel (FOB refinery), or 34¢/gallon (\$14.28/barrel, FOB plant). The fuel oil is rated at 150,000 Btu/gallon indicating a price of \$2.26/MBtu.

Even though the fuel oil is less expensive per MBtu than the natural gas, the plant burns natural gas whenever it can because natural gas is thermally more efficient in addition to being more convenient. The physical ability of the boiler to burn fuel oil is not as efficient as burning natural gas because fuel oil soots up the boiler tubes and reduces the thermal efficiency of the heat transferred. Thus, the boiler efficiency is reduced and the steam output per Btu is less than for natural gas.

VIII. KEY PROBLEM AREAS

- (1) Environmental requirements especially with respect to sulfur content of fuel oil and coal.
- (2) Cooperation from the utility with respect to:
 - (a) High standby service charges.
 - (b) Providing available forecasts of natural gas curtailments and electrical energy costs.

APPENDIX A-10

COGENERATION SITE REPORT
TIMBER INDUSTRY

SIMPSON TIMBER COMPANY

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Air Basin: North Coast
APCD: Humboldt County
AQMA: None

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This site report is based on notes taken by survey team members during visits to the plant, telephone conversations with plant personnel, and various reports furnished by the company. The report has been reviewed and approved by the company. The opinions, attitudes, and conclusions expressed in the report are those of the company and not necessarily those of the Jet Propulsion Laboratory.

I. GENERAL INFORMATION

The Simpson Timber Company, headquartered in Seattle, Washington, is a privately owned and managed company. Simpson operates in Canada and the United States with sawmills, plywood manufacturing plants, pulp and paper plants, building supply operations, and intensive programs in resource management and half a million acres of timberland. About 300,000 acres of that are in California, with the remainder in the Pacific Northwest. In addition to its own land, Simpson has management responsibilities and harvest opportunities on other lands in the United States and Canada.

Production capacity and classification of the five plants are as follows:

| <u>Plant</u> | <u>Type of Plant</u> | <u>Miles from Arcata</u> | <u>Production Capacity</u> |
|--------------|------------------------------------|--------------------------|----------------------------------|
| Arcata | Lumber manufacturing | 0 | 6 x 10 ⁶ board ft/yr |
| Fairhaven | Plywood | 11 | 320,000 SF/day (3/8" plywood) |
| Klamath | Sawmill | 70 | 85,000 board ft/day |
| Korbel | Sawmill and lumber remanufacturing | 11 | 400,000 board ft/day |
| Mad River | Plywood | 1 | 400,000 SF/day (3/8" plywood) |

The basic product of these plants is fir and redwood plywood and redwood lumber. Some fir and hemlock timber is processed, but only on a very limited basis.

The federated trade organization for the timber industry is the National Forest Products Association which is also the industry lobby. In California Simpson Timber is also active in the California Manufacturers Association and the California Forest Protective Association. The primary trade publication is Forest Industry.

Simpson Timber is in competition with Miller Redwood, Arcata Redwood, Louisiana Pacific, Georgia Pacific and Pacific Lumber. Simpson Timber, along with Pacific Lumber and Louisiana Pacific, are the largest producers in the state for redwood plywood, all producing about the same quantities. Simpson Timber is rather small in the production of fir plywood, but is considered to be an innovative leader in the production of redwood lumber and plywood.

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II. PLANT PROCESS

Of the five California plants, only the Korbel sawmill was toured. At Korbel the operation is fairly straightforward. Logs are debarked using an advanced hydraulic system; then high pressure jets debark the log as it is rotated. Even though the hydraulic debarker is a high energy user, hydraulic debarking is more efficient for large, thick-barked redwood. In order to avoid any water pollution problems, the process water is treated within a large clarifier and recycled for further use.

The logs are cut to rough lumber sizes and sold either as rough lumber to finishing mills or stacked outside for natural drying, which may take up to two years prior to finishing. To finish, the lumber is placed in kilns or dryers, then followed by a planing operation.

Coarse residue and sawdust from the mill called "hog fuel" is used as a byproduct fuel for the plant's large boiler. Chips from residue wood chopped up in the plant, are sold in large quantities; they are mainly used to make paper pulp with some being sold for nursery products. Redwood bark is too moist to use as fuel so it is burned in a large on-site "smokeless incinerator".

III. COGENERATION POTENTIAL

Cogeneration projects have been investigated for the Fairhaven and Mad River plywood plants and it has been determined that, at the present time, it is not economically feasible to cogenerate in California. Cogeneration will not become practical until PG&E cooperates with respect to wheeling of power and offers reasonable standby charges.

The most economical concept for Simpson is to build one large central cogeneration power plant and wheel the power to their various plants. The steam could not be transported so it would most likely be a condensing, extraction turbine system.

A local engineering firm, Windsor and Kelly of Arcata, has performed a study for Humboldt County utilizing a resource recovery boiler to burn refuse derived fuel. In addition, Humboldt County is seeking new methods for waste disposal and a resource recovery boiler would be suited to their needs. A joint project sponsored by Humboldt County is quite attractive at this time. A resource recovery boiler would burn a mixture of solid waste and hog fuel supplied by the County and Simpson Timber respectively, at the rates shown below:

| | <u>Quantities (tons per day)</u> | |
|---|----------------------------------|-------------------------------|
| <u>Fuel Type</u> | <u>Initial Startup</u> | <u>20 years after Startup</u> |
| Primary Fuel (domestic solid waste) | 280 | 500 |
| Supplemental fuel (hog fuel) | 450 | 250 |

Unit energy capacity for domestic solid waste is not known at this time; hog fuel varies from 4000 Btu/lb (50% wet) to 8000 Btu/lb (dry).

A detailed design has not yet been performed for the resource recovery boiler, but it would be similar to an off-the-shelf type wood waste boiler, and it would produce 250,000 lb/hr of 600 psig, 750°F steam. This process steam would be sold to a PG&E power plant.

PG&E would install a 25 MWe (full capacity) power station adjacent to the boiler. A condensing steam turbine would match the boiler steam and drive a 25 MWe rated generator at about 20 MWe output. An extraction steam turbine would also be considered with bleed-off steam used to pre-heat the feed water and perform other tasks.

Water supply could be a problem, since the condenser would recirculate 50×10^6 gals per day (gpd). With evaporation taking place, a 1×10^6 gpd makeup requirement would exist. Switching gear and auxillary equipment would bring the estimated total cost in the neighborhood of \$25 million. PG&E currently plans to sell the power at 37 mills/kWh and does not want to discuss future escalation. It might be noted at this date that for power PG&E is willing to purchase they will pay 17 mills/kWh for base load power and 14 mills/kWh for surplus power.

IV. ECONOMIC CONSIDERATIONS

The Simpson Timber Company expects a payback period of from four to five years. Major investment decisions are made at the company headquarters in Seattle, Washington. A project like cogeneration would be analyzed at headquarters after the feasibility has been determined at the local level.

Capital commitment for Simpson is on a priority rating system. Top priority is given to those projects with the largest rate-of-return and smallest payback periods. The facility projects, relating to expansion and production line improvements, generally have the highest priority, with energy and environmental projects having the lowest priority. Cogeneration projects in Simpson's California operations have a low priority at this time.

V. ENVIRONMENTAL ISSUES

The company has installed a smokeless burner for disposing of redwood bark and a zero-discharge water purification and recycling system for debarking logs hydraulically at the Korbel sawmill.

The New Source Review Rules do not appear to pose any major obstructions to cogeneration implementation at this time. Proximity to a Class 1 area could result in more stringent particulate standards within the buffer zone which would require installation of more expensive control equipment.

Coastal zone restrictions might hamper siting an energy facility for cogeneration within the coastal zone.

VI. INSTITUTIONAL ISSUES

The timber industry has an abundant supply of residue wood, or hog fuel, which can be utilized as fuel. A general characteristic of plants within the industry is that they have enough hog fuel to generate more steam and electricity than needed. Ideally, a plant owner would like to burn all his hog fuel to generate electricity and steam. The excess electricity could be "wheeled" to other plants, and steam could be either sold to local firms or dumped. In the Northwest, wheeling is a common practice, but in California industrial wheeling has been blocked by the utilities for years.

For two years, Simpson Timber has been turned down by PG&E with respect to the "wheeling" principle. Simpson has capacity in their State of Washington operation to support some of their California plants in case of an emergency. Another wheeling option could be arranged with Crown-Simpson Paper Company, a pulp mill located adjacent to the Fairhaven plywood plant. Other alternatives are under study. Simpson Timber would like some type of wheeling arrangement, but PG&E has not cooperated to date.

If cogeneration were implemented, the Simpson plants would require standby power from PG&E. The problem here is establishing a standby charge for power that is mutually acceptable by Simpson Timber and PG&E. Finally, according to Simpson Timber, the price PG&E is willing to pay for excess power is about half of what they sell it for and they will not discuss rate escalation. No consideration is given to "new source" costs.

Permits for the proposed cogeneration project are expected to be very difficult to obtain. It was estimated by Windsor and Kelly that the environmental permits alone would take 20 to 24 months to obtain and the total permit process would take at least three years. It was suggested that the State of California review the concept used by the State of Washington's Department of Ecology. The department has a "one-step" permit procedure where all permits (municipal, county, state, and federal) are obtained from one source. After submitting an application, a review is made and a permit processing completion date given to the applicant. If the department does not meet this date, all permits are automatically approved, and the project can commence. This type of procedure would benefit cogeneration implementation.

VII. TECHNICAL DATA

A. PROCESSING EQUIPMENT

The processing equipment for each site is listed below:

- (1) Arcata. The redwood remanufacturing plant has two boilers. One is operational and burns natural gas; the standby boiler burns diesel fuel. The plant has 26 kilns and operates on a continuous basis, operating with two shifts seven days per week, 238 days per year.

- (2) Fairhaven. This plywood plant has two boilers that burn hog fuel and supply steam to four veneer dryers. There are nine block steaming vaults, three plywood presses, and other assorted equipment. The plant is operational 24 hours per day, five to six days per week, and 240 days per year.
- (3) Klamath. Klamath is a small "one-sides" sawmill having only mechanical equipment and no steam requirements. The sawmill is too far away to economically transport their hog fuel to the other plants, so the sawdust is burned onsite with the bark. Some of the redwood chips are sold to Crown-Simpson Paper Company as pulp. (Simpson Companies all operate independently and products are bought and sold among them as though they are separately owned.) The Klamath plant operates one shift Monday through Friday for 238 days per year.
- (4) Korbel. Korbel is a redwood sawmill having one boiler that burns hog fuel; it is operated at half capacity. In addition, there are 13 kilns. The plant operates on a continuous basis 24 hours per day, seven days per week, and 238 days per year.
- (5) Mad River. This plywood plant has two boilers that burn hog fuel and supply steam to four operational dryers. A fifth dryer is used on a standby basis. There are three plywood presses and the equipment is operated 24 hours per day, five days per week, and 240 days per year.

B. PROCESS ENERGY PROFILE

1. Electrical Demand

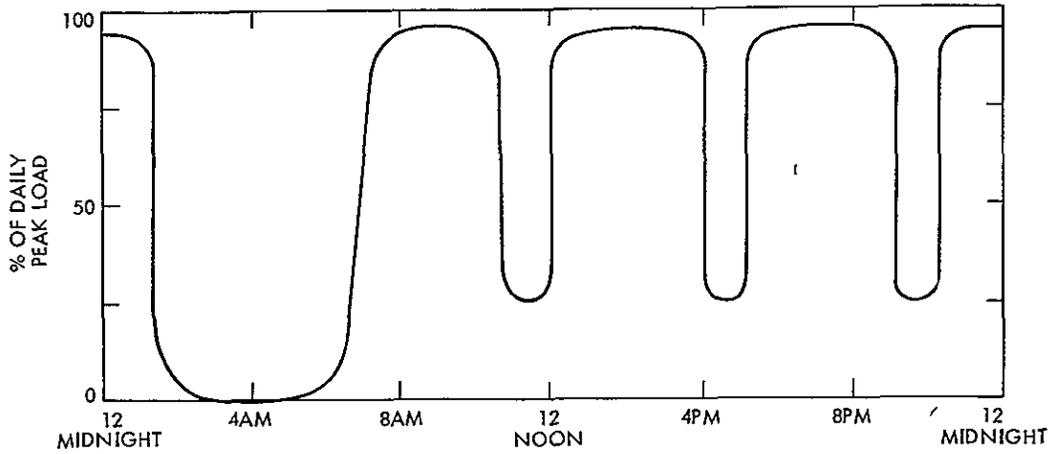
Four of the five plants (Arcata, Fairhaven, Korbel, and Mad River) are served by PG&E at an average rate of 32.7 mills per kWh. The average rate of the Klamath sawmill, serviced by Pacific Power and Light, was 23 mills. The Korbel sawmill is on a time-of-day rate structure and the remaining plants are expected to follow suit in the near future.

The electrical demand for each plant follows:

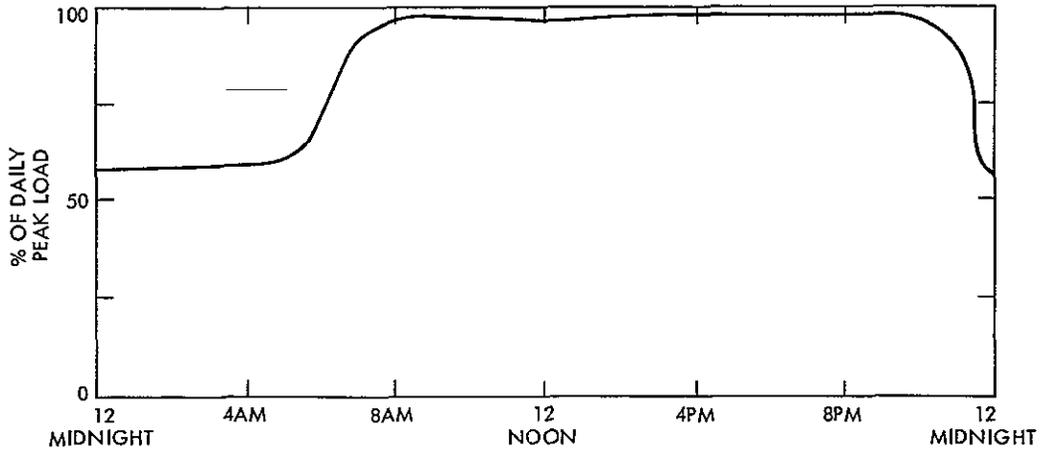
| Plant | Peak Demand, MWe | Average Usage, 10 ⁶ kWh/mo. | Load Variations | |
|-----------|---------------------|---|-----------------|--------------|
| | | | Daily Graph | Annual Graph |
| Arcata | 2.2 | 1.5 | A | D |
| Fairhaven | 2.7 | 1.8 | B | D |
| Klamath | 0.9 | 0.9 | C | D |
| Korbel | 4.4 | 5.5 | A | D |
| Mad River | 2.7 | 1.8 | B | D |

The daily and annual variations are shown in the following graphs, with the first three daily graphs representing A, B, and C curves for the specified plants shown in the previous table.

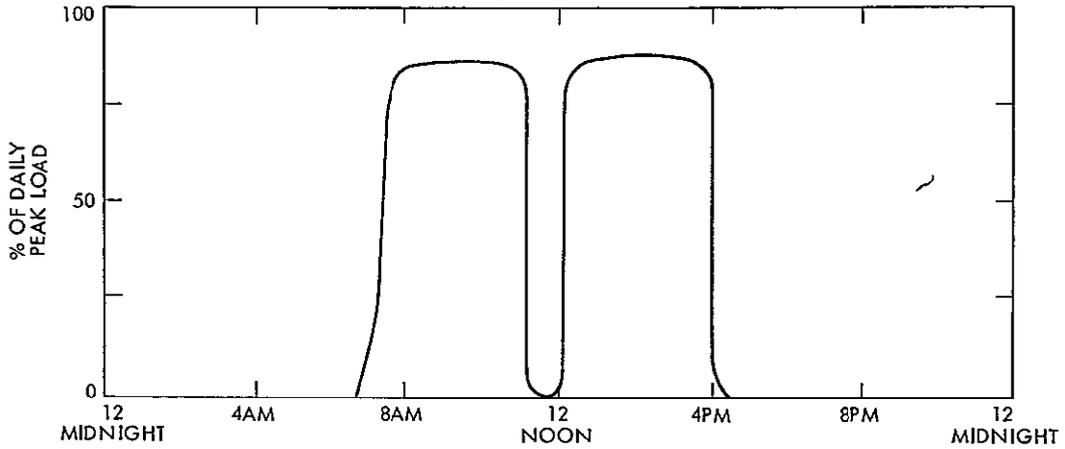
ARCATA AND KORBEL - DAILY (GRAPH A)



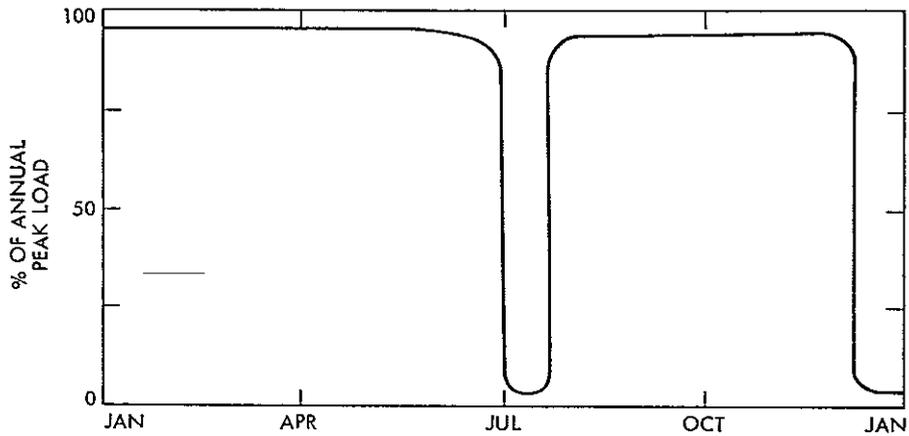
FAIRHAVEN AND MAD RIVER - DAILY (GRAPH B)



KLAMATH - DAILY (GRAPH C)



ALL FIVE PLANTS - ANNUAL VARIATION (GRAPH D)



2. Steam Load

The Klamath sawmill does not use process steam; the steam characteristics of the remaining four plants are shown below:

| Plant | Quantity, lb/hr | Pressure, psig | Temp | Boiler Operations | |
|-----------|--------------------|-------------------|--------------------|-------------------|---------|
| | | | | % of Capacity | Days/wk |
| Arcata | 15,000 | 15 | Saturated steam | ? | 7 |
| Fairhaven | 80,000 | 250 | | 80 | 6 |
| Korbel | 15,000 | 15 | | 50 | 7 |
| Mad River | 70,000 | 250 | | 60-70 | 6 |

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3. Fuel Use

The Arcata plant burns natural gas (135,000 therms per month) and has diesel fuel available for standby (which they have not used for 1-1/2 years). The three remaining plants, Fairhaven, Korbek, and Mad River, all burn hog fuel. The Klamath sawmill purchases electricity and does not use steam.

VIII. KEY PROBLEM AREAS

The major problem areas with respect to cogeneration implementation are as follows:

- (1) Privately owned company financial investment criteria which sets low priority for energy saving expenditures as compared to production-related projects.
- (2) Strict environmental regulations and uncertainties imposed by the various environmental agencies.
- (3) Mutually acceptable agreements with PG&E on wheeling, standby charge, surplus charge, and rate escalation issues.
- (4) Delays and pitfalls of the State of California environmental permit procedure.

APPENDIX A-11

COGENERATION SITE REPORT
SUGAR BEET REFINING INDUSTRY

SPRECKELS SUGAR COMPANY
MANTECA PLANT

Participants

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Jet Propulsion Laboratory

V. C. Moretti
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Air Basin: San Joaquin Valley
APCD: San Joaquin County
AQMA: Stanislaus - San Joaquin

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Amstar Corporation
Spreckels Sugar Division
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San Francisco, CA 94111
(415) 362-5600

This site report is based on notes taken by survey team members during visits to the plant, telephone conversations with plant personnel, and various reports furnished by the company. The report has been reviewed and approved by the company. The opinions, attitudes, and conclusions expressed in the report are those of the company and not necessarily those of the Jet Propulsion Laboratory.

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I. GENERAL INFORMATION

Spreckels Sugar Company is considered to be an innovative leader in the beet sugar industry. In 1967-1968 Spreckels remodeled their Manteca plant to increase capacity and at the same time improved their total heat balance throughout the plant. Currently, their Spreckels California plant near Salinas is being remodeled, and the project should be completed next spring.

Spreckels Sugar is a subsidiary of Amstar Corporation, an East Coast firm which refines cane sugar. The company owns four beet sugar refineries in California and is the largest producer in the state and third in the nation. The largest producer in the nation is Great Western Sugar, located in Colorado. There are nine beet sugar refineries in California.

The Manteca plant processes 4200 tons of sugar beets per day, which yield about 10,000 hundred weights of sugar, equivalent to 500 tons. The plant has 330 employees and operates on a continuous basis 300 days a year.

Spreckels' competitors in California are Holly Sugar, Union Sugar, and American Crystal for beet sugar, and C&H sugar, which produces cane sugar. There is no difference in the sugar produced from beets and cane; however, the processes are different. Cane sugar must be extracted from the cane and processed into a raw sugar which is then refined to a pure sugar for market, usually at another facility. Beet sugar, on the other hand, is processed directly from the beets through extraction, purification, and crystallization of the final white sugar, all within a single factory. The difference in the processes is that the extraction-process for cane sugar is done abroad and the raw sugar is shipped to the cane sugar refineries; beet sugar is extracted and refined at the same factory. The extraction process is more energy-intensive than the refining process.

II. PLANT PROCESSING OPERATION

Raw sugar beets are cleaned and sliced mechanically into cossetts which look like shoestring potatoes. The cossetts are then put through a diffusion process which extracts the sugar from the beets. The Manteca plant has two diffusers which use secondary steam to raise diffusion water temperatures to 80°C. At the end of the diffusion process, the near-sugarless cossetts (beet pulp) go to a drying process and are then used for cattle feed. The sugar in solution, called diffusion juice, has many impurities at this stage. The next step is to remove these impurities; the diffusion juice is heated to 85°C and then put into a carbonation process where it is mingled with milk of lime. A lime kiln produces carbon dioxide and lime for this process;

the by-product from the carbonation process, calcium carbonate, is recycled into ponds and mined after a three year period for use in the kiln. The resulting thin juice from the carbonation process has most of the impurities removed and consists of about 10 percent sugar.

The evaporation process concentrates the sugar in a thick juice which contains about 60 percent sugar. This process involves the use of five evaporation stages and reduces 1200 gallons of thin liquid down to 400 gallons of thick liquid through evaporation.

The next stage is an activated-carbon treatment process to remove some of the remaining impurities, which will produce a juice, about 88 percent pure. This thick juice goes into high and low melters and dissolves the sugar crystals in syrup.

The sugar syrup is boiled at reduced pressure and temperature until the solution is saturated; it is then given a mechanical shock to cause crystals to form. The crystal growth process is watched carefully, and at the proper time growth is halted. The crystal mixture is then centrifuged and washed. The resultant damp sugar is dried before storing.

In a beet sugar plant the energy used for the actual sugar refining is basically waste heat from the raw material or extraction part of the process. The sugar refining process is the last part of the whole process for beet sugar, whereas it is the entire process for domestic cane sugar; thus, there is a significant difference in the energy use in the two industries.

III. COGENERATION POTENTIAL

The Manteca plant was modernized from 1967 to 1968 in order to double plant capacity. At that time, the plant was heat balanced in order to fully utilize electrical generation in conjunction with the steam production required for the process. The cogeneration electrical output of 4.2 MW meets about 80 percent of the plant's needs. The plant does not have the capability to generate more power than it consumes and, therefore, cannot sell power to PG&E. Their self-generated power is in parallel with the power from PG&E. Table 1 gives a description of the cogeneration equipment. In addition, there are seven steam turbines, which are used to generate mechanical energy. The plant is totally heat balanced utilizing exhaust steam in a five effect-evaporation system. Boilers 1 and 2 generate 220,000 lb/hr; 19,000 lb/hr is used for mechanical energy driving one 500 hp and two 400 hp turbines; 135,000 lbs/hr goes directly to the turbogenerator, and another 4,000 lb/hr drives the variable frequency generator; 11,000 lb/hr drives a 450 hp steam turbine and 7,200 lb/hr drives a 275 hp steam turbine. The remaining steam is desuperheated and combined with all the exhaust steam yielding 173,000 lb/hr used for the evaporators, 3,000 lb/hr used for the granulator heaters, and the remaining 12,000 lb/hr to the three stages of the crystallization process. The energy to refine the sugar, which comprises the crystallization process, is basically waste heat from the evaporation process.

Table 1

| Type | Size | Age, yr | Life, yr | Duty Cycle | Maintenance | Capital Cost |
|------------------------------------|---------|---------|----------|------------|---|---|
| G.E. turbo-generator | 5.0 MW | 14 | 20 | Steady | None - nominal inspection every 3 years | Replacement cost: \$1.2 million installed |
| Terry variable frequency generator | 0.15 MW | 14 | 20 | Steady | | |

The turbogenerator is a single-shaft, noncondensing type. The characteristics of the inlet steam are 400 psig at 600°F; the steam outlet is 45 psig, saturated condition.

The Spreckels' plant near Salinas is now undergoing modernization and is expected to be operational in the spring of 1978. This plant will also be heat balanced for a cogeneration potential of 7.0 MW of electricity. Planned expenditures for the Salinas plant are about \$6.35 million, and the company is planning to replace a number of inefficient boilers as part of the project.

IV. ECONOMIC CONSIDERATIONS

The company uses the discounted cash flow method for evaluating projects and expects a return on investment (ROI) of 20 to 25 percent. However, equipment replacements, product improvements, and environmental expenditures do not need to meet this criteria.

The depreciation method used for tax purposes was not obtained, but it is most likely an accelerated depreciation method. At the present time, energy costs comprise about 12.5 percent of the total product cost.

V. ENVIRONMENTAL ISSUES

SO₂ requirements limit the ability of Spreckels Sugar to acquire fuel oil. They are a small purchaser, and with a limited world supply it is difficult for them to buy what they need. With respect to the fuel used in their dryers, the sulfur is absorbed in the beet pulp and

is not released to the atmosphere. However, the regulation specifies a maximum sulfur content in the oil supplied to the burners but does not address the stack emissions. Therefore, the low sulfur fuel requirement for the dryers is unnecessary.

The company is not convinced that 0.5 percent sulfur fuel emits significantly fewer pollutants out the stack and would like to see an environmental study on the effects of SO₂. To install scrubbers in their boiler stacks would be too expensive, about \$2 million per stack or \$6 million total. In addition, they are not sure of the technology of this equipment.

Currently, the Manteca plant is burning 0.2 percent sulfur fuel, and they do not know what the future requirements are going to be. With more stringent requirements, the boiler stacks will cause the biggest problem. With the economics of the sugar industry as they are, the company could not consider the large capital expenditures required for environmental control.

VI. INSTITUTIONAL ISSUES

Spreckels Sugar considers their relationship with PG&E to be good. The utility has been cooperative and very responsive when service is needed. Spreckels does not like the rate they pay but feels that the utility does not have control over that anyway.

VII. TECHNICAL DATA

A. PROCESSING EQUIPMENT

Table 2 depicts the types and operational characteristics of the equipment used in the process.

There are no future process modifications anticipated which would alter the plant's steam requirements.

B. PROCESS ENERGY PROFILE

1. Electrical Demand

The Manteca plant has a peak demand of 5.4 MW which occurs about six times a year, and for only a few minutes at each occurrence, after a factory shutdown or equipment failure. The base load is 5.0 MW, of which 4.2 MW is cogenerated and 0.8 MW is purchased from the utility. There is a slight daily load variation as depicted in the graph on page A-104.

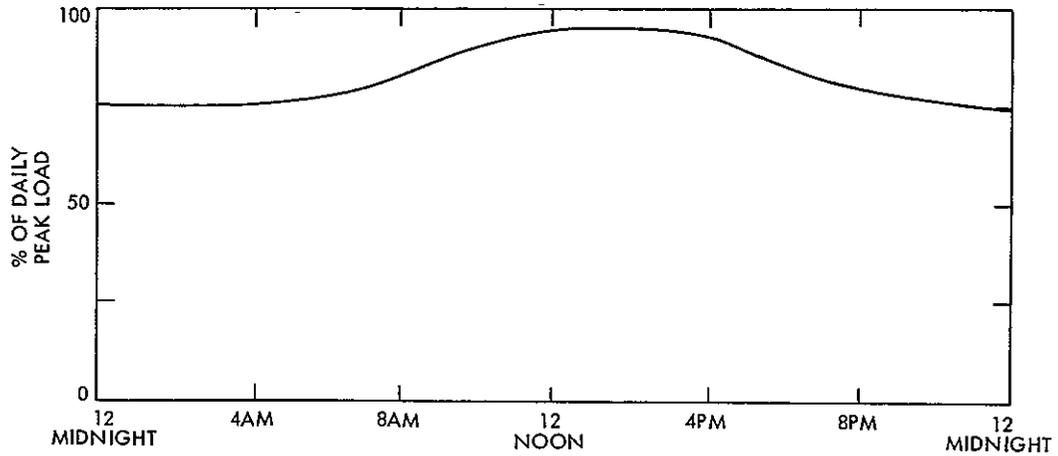
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Table 2

| Type | Size | Age, yr | Life Expectancy, yr | Type of Energy Used | Duty Cycle S= Steady V=Variable | Maintainability and Reliability Record | | Location (clustered vs. scattered) | Future Plans E=Expansion M=Modernization R=Replacement |
|-----------------|--|---------|---------------------|-------------------------------------|---------------------------------------|--|--------------------------|------------------------------------|---|
| | | | | | | Major Repairs per yr | Operator Man-yrs | | |
| Package Boilers | | | | | | | | | |
| 1. | 100,000#/hr | 13 | 20 | Natural gas or #6 fuel oil | S | \$20-25,000 | 1 operator for 3 boilers | C | None |
| 2. | 125,000#/hr | 10 | 20 | | S | \$20-25,000 | | C | None |
| 3. | 17,000#/hr | 60 | 0 | | -- | -- | C | C | Being replaced New, to be installed |
| 4. | 50,000#/hr | New | 20 | | S | No history | | | |
| Kilns | | | | | | | | | |
| 1. Lime kiln | 1x10 ⁶ ft ³ /day | 10 | 20 | Natural gas or fuel oil | S | Less than \$8,000 | No oper. | 1 location | |
| 2. Carbon kiln | 30,000 ft ³ /day | 10 | 20 | Nat. gas only | S | Less than \$1,000 | No oper. | | |
| Pulp Dryers | | | | | | | | | |
| 1. | 10"-6" Ø dia each | 17 | 20 | Nat. gas or fuel oil directly fired | S | \$10,000 each | 1 oper. for both | C | None |
| 2. | 10"-6" Ø dia each | 10 | 20 | | | | | | |

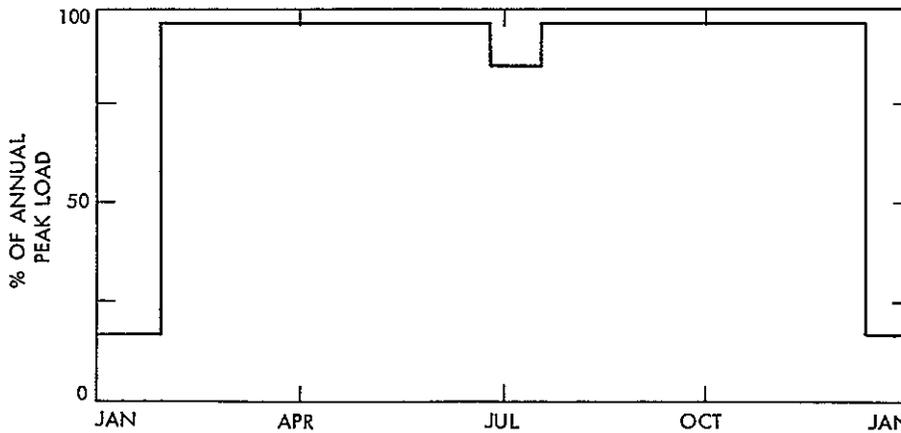
A-103

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Purchased electricity costs about \$10,000/month at a price of 3.5¢ per kWh.

The annual electrical load variation is depicted in the following graph. The plant is shut down for about 60 days at the end of December plus an additional three or four days in July. The rest of the year, operation is continuous around the clock.



2. Steam Load

The steam load of the plant is 220,000 lb/hr with minimal variation throughout the day. The annual steam load is continuous 300 days a year, and the plant is shut down for 60 days a year.

3. Fuel Use

The Manteca plant can burn natural gas or No. 6 bunker C fuel oil in the boilers, dryers, and lime kiln. Only natural gas can be burned in the carbon kiln. The natural gas priority is P3 for the dryers and carbon kiln and P4 for the boilers. Therefore, from a gas curtailment incentive, there is less motivation to convert the dryers to oil.

VIII. KEY PROBLEM AREAS

Major problems with respect to additional cogeneration implementation are as follows:

- (1) Environmental control restrictions with respect to the sulfur content of fuel oil.
- (2) Disruption of the plant's existing cogenerating heat balance.

APPENDIX A-12

COGENERATION SITE REPORT
PETROLEUM REFINING INDUSTRY

UNION OIL COMPANY
WILMINGTON

Participants

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Utility: Los Angeles Department of Water and Power (LADWP)
Air Basin: South Coast
APCS: South Coast Air Quality Management District
AQMA: South Coast

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This site report is based on notes taken by survey team members during visits to the plant, telephone conversations with plant personnel, and various reports furnished by the company. The report has been reviewed and approved by the company. The opinions, attitudes, and conclusions expressed in the report are those of the company and not necessarily those of the Jet Propulsion Laboratory.

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I. GENERAL INFORMATION

The Union Oil Refinery is located in Wilmington near San Pedro in Los Angeles County. Constructed in 1919, it is one of the oldest petroleum refineries in California. The refinery processes an average of 108,000 barrels/day of crude oil plus an additional 40,000 barrels/day of other raw materials. Fifty-five percent of its output is gasoline; turbine fuel, diesel fuel, solvent, and low-sulfur oil make up the rest of the product mix. Highly specialized fuels or products are not made at this refinery.

I. PLANT PROCESSING OPERATION

The Union Oil refinery typifies the standard petroleum refinery process. Crude oil is brought into three crude processing units: Unit (1) produces gas where a special treatment for clean fuel gas is performed; Unit (2) produces a gasoline blending stock; and Unit (3) produces turbine and diesel fuel. Additional processing is performed on by-products.

How a particular crude oil input will break down for processing in the refinery is determined in advance and adjustments are made before the particular batch is processed.

The refinery has an extensive heat exchange system. There are approximately 65 furnaces which are basic units to the process. These furnaces vary in size and all are over 1 million Btu/hr with stack temperatures varying from 300 to 900°F. At the present time the refinery produces steam from product waste heat in four locations for a total of 450×10^6 lb/mo., 450 psi saturated steam. The largest steam producers other than the boiler plant are the Fluid Cat Cracker (FCC) unit and a catalytic reforming unit.

III. COGENERATION POTENTIAL

Union Oil has a preliminary study in progress at the corporate level. The Wilmington refinery has two areas that lend themselves to cogeneration with a potential of 40 MW at a capital cost of about \$20 million.

A 20 MW potential exists with the FCC unit as the prime source. The FCC unit maintains a 25 psig steady pressure. The proposed insertion of an expander (turbine-generator) to replace the valve will facilitate the generation of usable energy. Such a conversion calls for a capital expenditure in the neighborhood of \$8-12 million. If a new FCC unit were installed, this type of unit would be included; however, conversion of an existing FCC unit requires the elimination of some existing equipment.

Another 20 MW potential exists with the utilization of the carbon monoxide (CO) flue gas to run a low Btu gas turbine. The capital expenditure for this project would also be in the neighborhood of \$10 million.

The company would utilize the Los Angeles Department of Water and Power facilities to distribute power to its own refinery. The Department of Water and Power has indicated in a preliminary letter that it would consider such a proposition and is in the process of determining the charge for the arrangement.

It is not anticipated that the refinery would become a power producer and net exporter of electricity since the plant would always consume more electricity than it could cogenerate. The cost and availability of standby power is an important factor and could greatly influence the profitability of the cogeneration project.

IV. ECONOMIC CONSIDERATIONS

The Wilmington refinery spends up to \$10 million a year on capital investment projects. Approximately 30 percent of the proposed projects are energy related. Projects which reduce costs take precedence over those which will result in market or sales expansion. The basis for evaluating projects is their expected return on investment (ROI); to become an acceptable investment the ROI for a cogeneration project should be about 20 percent.

A major portion of the capital is currently spent satisfying government requirements. In the last 10 years little capital has been expended to significantly improve product throughput. The reduction of energy consumption could become part of the investment decision criteria.

The Los Angeles Department of Water and Power has recently undergone a review of its rate structure by a Blue Ribbon Committee formed by the Mayor of Los Angeles. The committee, which is primarily consumer- rather than industry-oriented, recommended that a flat time differentiated rate block rather than a declining rate structure be adopted. Opposition to this new tariff has been expressed by large industrial users.

V. ENVIRONMENTAL ISSUES

It is Union Oil Company's understanding that the Air Resources Board is currently considering new SOx and NOx requirements. If true, it could be another year before the regulations are promulgated. This state of flux in environmental regulations affects Union Oil Company plans for their process, their products, and the installation of cogeneration equipment. The New Source Review Rules require that equipment be removed which more than offsets new equipment being installed. No credit is allowed for the power that is generated which alleviates the load from the utility. All of these environmental questions tend to reduce the attractiveness of cogeneration.

VI. INSTITUTIONAL ISSUES

The Union Oil Company has approached the Los Angeles Department of Water and Power on the subject of cogeneration, and the utility has indicated they would consider any proposal. This attitude represents a change over the past year; previously, the utility was a strong solicitor for customers and appeared to be uninterested in cogeneration projects.

VII. TECHNICAL DATA

A. PROCESSING EQUIPMENT

There are seven boilers clustered in a utility area of the Wilmington refinery. Boilers 1-5 produce a combined total of 550,000 lb/hr, and boiler 7, which is the carbon monoxide (CO) boiler, produces 240,000 lb/hr. These boilers are in continuous operation around the clock. In addition, boiler 6 has the capability to produce 200,000 lb/hr but is utilized as a standby. All boilers formerly used natural gas, but are now on fuel oil or refinery gas.

There are many furnaces throughout the refinery which operate at 70-80 percent efficiency. Economizers and preheaters have been installed in some exhaust stacks and stack temperatures are in the neighborhood of 300-800°F.

There are also many heat exchangers which are constantly monitored, some by computer. As soon as any degradation in performance occurs, they are prepared for cleaning.

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B. PROCESS ENERGY PROFILE

1. Electrical Demand

Electrical demand is constant. Everything runs all the time and is shut down only for major maintenance. The refinery averages 30-35 x 10⁶ kWh/mo with a demand average of 50 MWe at a cost of about 3.1¢ kWh, including both demand and usage charges. The daily load factor remains fairly constant at about 85-98 percent, and varies only when there is a major equipment shutdown.

2. Steam Load

| Boiler | Quantity, lb/hr | Temp., °F | Pressure, psi | Type of Fuel Used |
|---------------|--------------------|--------------|------------------|----------------------------------|
| 1 | 550,000 | 700 | 450 | Natural gas and fuel oil |
| 2 | | | | |
| 3 | | | | |
| 4 | 200,000 | 700 | 450 | Natural gas and fuel oil |
| 5 | | | | |
| 6 pkg. boiler | 240,000 | 700 | 450 | Natural gas, CO, and fuel oil |
| 7 CO boiler | | | | |

The average steam-load of the refinery is 625,000 lb/hr, excluding the CO boiler.

3. Fuel Use

Three types of fuel are utilized by the refinery: natural gas, refinery fuel gas, and low-sulfur fuel oil (0.5 percent). The refinery has the ability to switch from natural gas to alternate fuels in the furnace operations, which use 80 percent of the natural gas and have a priority of P3. The remaining 20 percent of the natural gas used in anti-knock compounds in gasoline has a priority of P2A. The company is looking at alternatives and expects the cost to be about \$15 million to install new equipment.

VIII. KEY PROBLEM AREAS

- (1) State of flux with respect to environmental regulations.
- (2) Meeting offset provisions of the New Source Review Rules established by the Air Resources Board.
- (3) Equitable utility rates for the purchase of power.

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APPENDIX B

ENERGY BALANCE EQUATIONS

Basic thermodynamic energy balance equations used in the analysis of the topping and bottoming cycle cogeneration systems calculated in this study are described in this appendix. A sample computation is given for a gas turbine cogeneration system. The energy needed to meet the plant demand was calculated and, in each case, compared to a base (nongenerating) system in order to determine the net energy savings. Energy units (10^6 Btu/hr) were converted to units of electric power (MWe), and conversely, by using the factor 3.412×10^6 Btu/MWe-hr.

I. TOPPING CYCLE

In the topping cycle, a gas or steam turbine is the prime mover. The exhaust (gas or steam) is utilized to produce steam for the plant's process.

A. GAS TURBINE

The gas turbine cogeneration systems utilize a waste heat boiler; if

E_{co} = energy required for the cogeneration system, Btu/hr

E_2 = energy output of turbine, Btu/hr (also defined as calculated cogeneration capacity in MWe, which is the cogeneration unit size)

Q_1 = gas turbine exhaust, the input heat to the waste heat boiler

Q_2 = heat out of the waste heat boiler, the process steam for the plant

η_{gt} = total efficiency of the gas turbine, including the compressor gear box, and generator

η_{wb} = efficiency of the waste heat boiler, including the feed water

then

$$Q_1 = Q_2 / \eta_{wb}$$

$$E_{co} = Q_1 / (1 - \eta_{gt})$$

and

$$E_2 = \eta_{gt} E_{co}$$

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B. STEAM TURBINE - BACK PRESSURE TYPE

The back pressure turbine cogeneration system provides process steam directly to the plant at a specified pressure and temperature. E_{co} and E_2 definitions are the same as for the gas turbine case. If

Q_2 = heat out of the turbine, the process steam for the plant

η_{st} = efficiency of the steam turbine power plant, which includes the boiler, turbine, gear box, generator, and all of the auxiliary equipment

then

$$E_{co} = Q_2 / (1 - \eta_{st})$$

and

$$E_2 = \eta_{st} E_{co}$$

C. STEAM TURBINE - CONDENSING TYPE

For a condensing steam turbine, the energy computations are based on an isentropic expansion with corresponding enthalpies obtained from the Mollier diagram. If

\dot{m} = mass flow of the steam into the turbine, lb/hr

h_1 = enthalpy in, output of the boiler, Btu/lb

h_2 = enthalpy out, Btu/lb of condensing steam at 0.5 psia after isentropic expansion

η_{ct} = efficiency of condensing turbine

W = work of the turbine, Btu/lb

E_2 = energy output of turbine, Btu/hr (same definition as for gas turbine)

then

$$\Delta h = h_2 - h_1$$

$$W = \eta_{ct} \Delta h$$

and

$$E_2 = \dot{m} W$$

D. STEAM TURBINE - EXTRACTION TYPE

For an extraction/condensing steam turbine, the same approach is used as for the condensing turbine. Assume a two stage extraction turbine; if

- \dot{m} = mass flow of the steam into the turbine, lb/hr
- x = fraction of mass flow being extracted at first stage
- y = fraction of mass flow being extracted at second stage
- h_1 = enthalpy in, the output of the boiler, Btu/lb
- h_I = enthalpy of steam at first stage after isentropic expansion
- $h_{I'}$ = enthalpy of steam in turbine after first stage work
- h_{II} = enthalpy of steam at second stage after isentropic expansion
- $h_{II'}$ = enthalpy of steam in turbine after second stage work
- h_2 = enthalpy out, the condensate
- η_{et} = efficiency of extraction, condensing turbine
- W_I = first stage work, Btu/lb
- W_{II} = second stage work
- W_{III} = final stage work
- W = work of the turbine, Btu/lb
- E_2 = energy output of turbine, Btu/hr (same definition as for gas turbine)

then

$$W_I = (h_1 - h_I) \eta_{et}^{1/3}$$

$$h_{I'} = h_1 - W_I$$

$$W_{II} = (h_{I'} - h_{II}) \eta_{et}^{1/3}$$

$$h_{II'} = h_{I'} - W_{II}$$

$$W_{III} = (h_{II'} - h_2) \eta_{et}^{1/3}$$

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$$W = W_I + (1 - x)W_{II} + (1 - x - y)W_{III}$$

and

$$E_2 = \dot{m}W$$

II. BOTTOMING CYCLE

In the bottoming cycle, high temperature waste heat and/or stack gases drive a gas turbine or pass through a waste heat recovery boiler which in turn generates steam to drive a steam turbine. An electric generator attached to the turbine (gas or steam) provides electricity for the plant.

A. GAS TURBINE

High temperature gases are cleaned and then used to drive a gas turbine/generator which then generates electricity. To eliminate blade damage, contaminated gases may be required to first pass through a heat exchanger rather than to pass directly into the turbine.

First, the gas heat capacity is required. If

Q_1 = heat available from high temperature gases, Btu/hr

\dot{m}_g = mass flow of gas, lb/hr

T_1 = temperature of gas at turbine inlet, °F

T_2 = temperature of gas out of waste heat boiler, °F

$\Delta T = T_1 - T_2$, °F

$T = T_1 + 460$, °R

$C_p = 0.219 + 0.342 T/10^4 - 0.293 T^2/10^8$, specific heat of gas, Btu/lb-°F

then

$$Q_1 = \dot{m}_g C_p \Delta T$$

This heat is equivalent to the energy required to operate the gas turbine for the topping cycle system. Thus,

$$Q_1 = E_{co}$$

and

$$E_2 = \eta_{gt} E_{co}$$

B. STEAM TURBINE

High temperature waste heat is captured and utilized to generate steam to drive a steam turbine, which in turn operates a generator to provide electricity for the plant. First, the heat available from the gases must be determined. The same equations are used as for the gas turbine bottoming cycle. After computing Q_1 , let

$$Q_2 = \text{heat out of heat exchanger}$$

$$\eta_{he} = \text{efficiency of heat exchanger}$$

then

$$Q_2 = \eta_{he} Q_1$$

If

$$\dot{m}_s = \text{mass flow of steam out of waste heat boiler, lb/hr}$$

$$h_1 = \text{enthalpy of steam out of waste heat boiler}$$

$$h_2 = \text{enthalpy of feedwater}$$

then

$$\Delta h = h_1 - h_2$$

and

$$\dot{m}_s = Q_2 / \Delta h$$

The steam exiting the heat exchanger is then used to directly drive a steam turbine. Equations previously developed for the condensing or extraction type steam turbines may then be used. In this context,

$$\dot{m} = \dot{m}_s$$

III. UTILITY ENERGY DISPLACED BY COGENERATION

Cogenerated energy, if delivered to the utility grid, could displace energy generated by a conventional central power station. In the figure, Plant II receives its energy requirement, E_{II} , from the grid. This energy, previously generated by the utility, is now assumed to originate from Plant I and available to Plant II via a tie-in to the grid. The cogenerated energy, i.e., the excess by-product energy, ΔE_I , is assumed to be equal to the displaced utility-generated energy, E_{DIS} , corrected for transmission losses and the efficiency of the utility power plant. That is,

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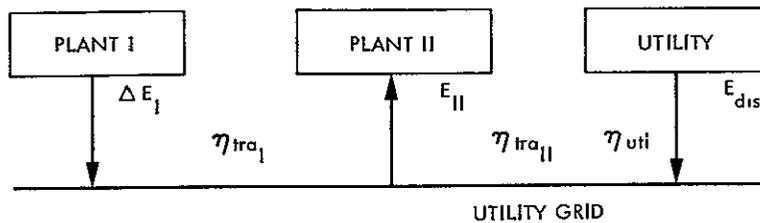
$$\Delta E_I \eta_{tra I} = E_{DIS} \eta_{utl} \eta_{tra II} = E_{II} .$$

The corresponding energy displaced by cogeneration is then

$$E_{DIS} = \Delta E_I \frac{\eta_{tra I}}{\eta_{utl} \eta_{tra II}} ;$$

where the corresponding cogenerated energy is the plant cogeneration capacity minus the plant electrical demand. That is,

$$\Delta E_I = E_2 - D_e .$$



IV. NET ENERGY EQUATIONS

The net energy savings is the benefit of the cogeneration system as compared to a standard base system for the same plant and utility power involved.

A. BASE SYSTEM

The base system is defined as the existing utility-dependent plant, which basically purchases the necessary energy to meet the plant's electrical and steam demands. If, for the base system,

η_{utl} = utility power plant efficiency

η_{tra} = utility transmission efficiency

\bar{C}_{plt} = average electrical demand capacity, MWe

D_e = plant electrical demand, Btu/hr

E_e = energy required to meet electrical demand, Btu/hr

\dot{m} = mass flow of process steam, lb/hr

p_g = gage pressure of process steam, psig

- P_a = absolute pressure of process steam, psia
 T = temperature of process steam, °F
 h = enthalpy of process steam, Btu/lb from steam tables
 D_s = plant steam demand, Btu/hr
 E_s = energy required to meet steam demand, Btu/hr
 η_b = plant boiler efficiency
 E_{base} = energy required to meet the base system electrical and steam demand, Btu/hr

Then, for the electrical demand,

$$D_e = \bar{C}_{plt} \times 3.412 \times 10^6$$

$$E_e = D_e / \eta_{utl} \eta_{tra}$$

and for the steam demand,

$$P_a = P_g + 14.7$$

$$D_s = \dot{m}h$$

$$E_s = D_s / \eta_b$$

Hence, for the base system the total energy required is

$$E_{base} = E_e + E_s$$

$$E_{base} = D_e / \eta_{utl} \eta_{tra} + D_s / \eta_b$$

B. NET ENERGY SAVINGS

The net energy savings is calculated by comparing the base system, adjusted for energy displaced by cogeneration, with a cogeneration system. The energy required for the cogeneration system is obtained from previous calculations, shown in prior sections of this appendix. If

E_{co} = energy required for the cogeneration system

E_{dis} = utility energy displaced by cogeneration

$E_{\Delta s}$ = supplemental energy required for boiler firing

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$E_{\Delta e}$ = supplemental energy required for purchased electricity

E_{net} = net energy required for the cogeneration system

E'_{base} = $E_{base} + E_{dis}$, base system energy, adjusted for energy displaced by cogeneration

then

$$E_{net} = E_{co} + E_{\Delta s} + E_{\Delta e}$$

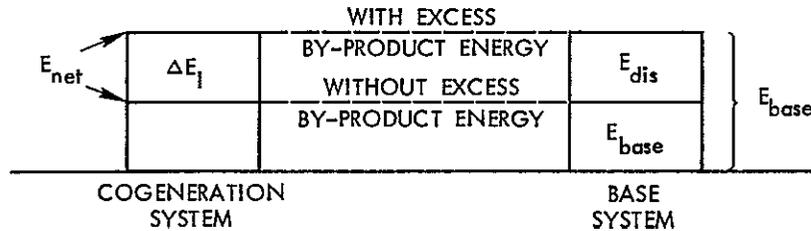
with the net energy savings

$$\Delta E_{net} = E'_{base} - E_{net}$$

and

$$\% \Delta E_{net} = \left(\frac{\Delta E_{net}}{E'_{base}} \right) \times 100$$

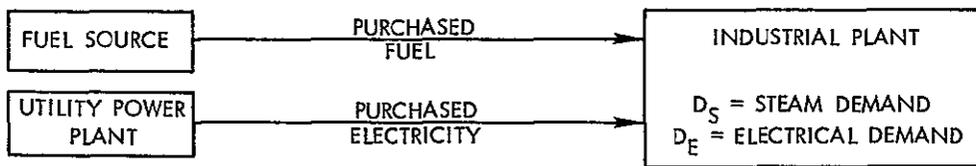
ENERGY REQUIREMENTS



V. SAMPLE CALCULATION

The California Paperboard Corporation is selected for the sample calculation. A gas turbine, topping cycle, cogeneration system is utilized, with plant data taken from the tables in the text and equations from this appendix. Plant energy requirements are computed for the base system and then for the cogeneration system. The net energy savings computations, the final step, were made by comparing the base system to the cogeneration system.

A. BASE SYSTEM



For the system demand:

$$\dot{m} = 70,000 \text{ lb/hr}$$

$$p_g = 140 \text{ psig}$$

$$p_a = 155 \text{ psia}$$

$$T = 400^\circ\text{F}$$

and, from steam tables,

$$h = 1219 \text{ Btu/lb}$$

Then

$$D_s = \dot{m}h = 70,000 \times 1219 = 85.3 \times 10^6 \text{ Btu/hr}$$

and

$$E_s = D_s / \eta_b = 85.3 \times 10^6 / 0.80 = 106 \times 10^6 \text{ Btu/hr}$$

For the electrical demand:

$$\text{Peak demand} = 4.4 \text{ MWe}$$

$$\text{Average demand} = 4.0 \text{ MWe}$$

Then

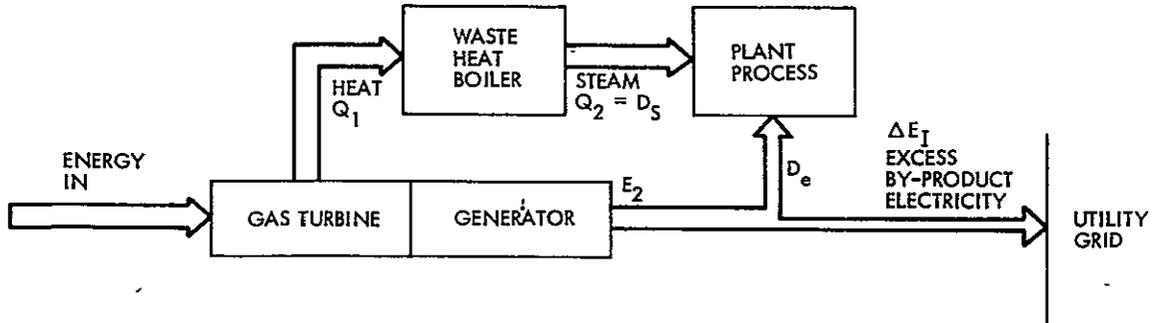
$$\bar{C}_{plt} = 4.0 \text{ MWe}$$

$$D_e = 4.0 \times 3.412 \times 10^6 = 13.6 \times 10^6 \text{ Btu/hr}$$

$$E_e = D_e / \eta_{utl} \eta_{tra} = 13.6 \times 10^6 / (0.37)(0.90) = 41 \times 10^6 \text{ Btu/hr}$$

$$\begin{aligned} E_{base} &= E_e + E_s \\ &= 147 \times 10^6 \text{ Btu/hr} \end{aligned}$$

B. COGENERATION SYSTEM - GAS TURBINE



$$\eta_{gt} = 0.27$$

$$\eta_{wb} = 0.75$$

$$Q_2 = 85.3 \times 10^6 \text{ Btu/hr (} D_s \text{ from base system calculations)}$$

$$Q_1 = Q_2 / \eta_{wb} = 85.3 \times 10^6 / 0.75 = 113.7 \times 10^6 \text{ Btu/hr}$$

$$E_{co} = Q_1 / (1 - \eta_{gt}) = 113.7 \times 10^6 / (1 - 0.27) = 156 \times 10^6 \text{ Btu/hr}$$

$$E_2 = \eta_{gt} E_{co} = 0.27(156 \times 10^6) = 42.1 \times 10^6 \text{ Btu/hr}$$

$$\text{Capacity of cogeneration unit} = 42.1 \times 10^6 / 3.412 \times 10^6 = 12.3 \text{ MWe}$$

1. Utility Energy Displaced by Cogeneration

From section III (Utility Energy Displaced by Cogeneration):

$$D_e = 13.6 \times 10^6 \text{ Btu/hr (from base system calculations)}$$

$$\Delta E_I = E_2 - D_e = 42.1 \times 10^6 - 13.6 \times 10^6$$

$$= 28.5 \times 10^6 \text{ Btu/hr}$$

Assuming the transmission losses are equal, i.e.,

$$\eta_{tra I} = \eta_{tra II}$$

then

$$E_{dis} = \Delta E_I \eta_{tra I} / \eta_{tra II} \eta_{utl}$$

becomes

$$E_{dis} = \Delta E_I / \eta_{utl} = 28.5 \times 10^6 / 0.37 = 77 \times 10^6 \text{ Btu/hr}$$

2. Net Energy Savings

Given

$$E_{co} = 156 \times 10^6 \text{ Btu/hr}$$

$$E_{dis} = 77 \times 10^6 \text{ Btu/hr}$$

$$E_{\Delta s} = 0$$

$$E_{\Delta e} = 0$$

then

$$E_{net} = E_{co} = 156 \times 10^6 \text{ Btu/hr}$$

and the net energy savings, ΔE_{net} , is

$$\begin{aligned} \Delta E_{net} &= E_{base} - E_{co} \\ &= 224 \times 10^6 - 156 \times 10^6 = 68 \times 10^6 \text{ Btu/hr} \end{aligned}$$

$$\% \Delta E_{net} = (68 \times 10^6 / 224 \times 10^6) \times 100 = 30\%$$

APPENDIX C

ASSUMPTIONS AND SUPPLEMENTAL COMPUTATIONS

| <u>System/Equipment</u> | <u>Efficiency, %</u> |
|---|----------------------|
| Utility power plant | 37 |
| Utility transmission | 90 |
| Steam turbine on-site power plant | 30 |
| Steam turbine unit, condensing and back pressure type | 80 |
| Steam turbine unit, extraction with condensing type | 73 |
| Gas turbine on-site power plant | 27 |
| Conventional boiler, new | 85 |
| Conventional boiler, old | 80 |
| Waste heat boiler | 75 |
| Counter flow heat exchanger | 60 |
| Fuel processing unit (partial oxidation) | 80 |

California Paperboard

- (1) Steam load of 70,000 lb/hr and the pressure of design alternative 2 as proposed in Slinger and Associates report.
- (2) Isentropic expansion for back pressure turbine.
- (3) Feedwater enthalphy negligible.
- (4) $\eta_{tra I} = \eta_{tra II}$
- (5) 313 operating days per year.

California Portland Cement

- (1) Computed electric demand = 15.8 MWe by using 10.43×10^6 kWh/mo demand from site report.
- (2) Determined number of operating days as follows:

Kiln operating

4 kilns 96% of time = $365 \times 0.96 = 350 \times 4/5 = 280$ days

1 kiln 70% of time = $365 \times 0.70 = 255 \times 1/5 = 51$ days

Plant operating days per year 331 days
- (3) Electric demand = $10.43 \times 12/331(24) = 15.8$ MWe.
- (4) Coal used to fire kilns:

4.7×10^6 Btu/ton of clinker $\times 1.11 \times 10^6$ tons/year =

596×10^6 Btu/hr.
- (5) Exhaust flow from kiln = 95,000 ACFM/Kiln @ 1100°F from SCE report, assumed at 15 psia.

- (6) Specific volume of exhaust = RT/p
 $V_E = 53.3(1100 + 460)/15(144) = 38.5 \text{ ft}^3/\text{lb}$
 $\dot{m} = 95,000 \times 60/38.5 = 148,000 \text{ lb/hr}$
- (7) Kiln load factor
 4 Kilns at 96% = 3.84
 1 Kiln at 70% = 0.70
 Total 5 kilns = 4.54
 Load factor = $4.54/5 = 0.91$
- (8) Total exhaust mass flow
 $\dot{m}_E = 148,000 \times 0.91 \times 5 \text{ kilns} = 673,000 \text{ lb/hr}$
- (9) Electrical output = 12 MWe
 Energy supplied to turbine = $12 \times 3.413 \times 10^6/0.8 = 51.2 \times 10^6 \text{ Btu/hr}$
 Heat into heat exchanger = $51.2 \times 10^6/0.6 = 85.3 \times 10^6 \text{ Btu/hr}$
 Heat into heat exchanger = kiln exhaust
 $Q_E = \dot{m}_E C_p \Delta T$
 $\Delta T = 85.3 \times 10^6 \text{ Btu/hr} / 673,000 \times 0.27 = 470^\circ\text{F}$
 Temperature of waste heat from heat exchanger = $1100 - 470 = 630^\circ\text{F}$.
- (10) Condensing steam turbine, $\eta = 80\%$
 Condensate = 90°F , 0.7 psia
 Isentropic expansion
 Steam inlet to turbine at 800°F
 Counter flow heat exchanger, $\eta = 60\%$
- (11) Gas turbine with compressor, $\eta = 27\%$
 Air-to-air heat exchanger, $\eta = 60\%$
 Kiln exhaust, heat value = $85.3 \times 10^6 \text{ Btu/hr}$ obtained from previous steam turbine calculation
- (12) 365 operating days per year

Exxon

- (1) Electric demand computed using plant's maximum capacity and a 90% load factor $D_E = 39 \times 0.9 = 35 \text{ MWe}$.

- (2) Average steam demand = 600,000 lb/hr, 600 psig, 750°F
 Four boilers = 150,000 lb/hr, refinery fuel gas
 Four gas turbines = 450,000 lb/hr, refinery fuel gas
- (3) No fuel is purchased for steam generation.
- (4) Utility owns cogeneration unit. They sell electricity and steam and purchase refinery fuel gas. This system would replace the four boilers.
- (5) Steam pressure drop and temperature losses = 10% pressure stepped down in the refinery.
- (6) 365 operating days per year.

Hunt-Wesson

- (1) Equivalent number of operating days
 Canning = 2.4×10^6 kWh/mo \times 1/4.2 MWe \times 1/24 = 24 days/mo.
 Off-season = 1.0×10^6 kWh/mo \times 1/2.1 MWe \times 1/24 = 20 days/mo.
- (2) Total operating hours per season
 Canning = 24 \times 24 \times 5 mo = 2880 hr
 Off-season = 20 \times 24 \times 7 mo = 3360 hr
- (3) Gas turbine sized for maximum condition; during off-season operation excess heat dumped.
- (4) Steam turbine sized for off-season conditions and during canning season steam supplied by conventional boilers.
- (5) Displaced energy computations assume $\eta_{tra I} = 1.0$, $\eta_{tra II} = 0.9$
- (6) Canning season = 120 operating days per year.
 Off-season = 140 operating days per year.

Husky Oil

- (1) For conventional steam injection assumed boiler efficiency = 85% with 10% steam energy losses for transporting steam to well location. Overall efficiency = $0.85 \times 0.90 = 0.77$.
- (2) Steam demand = 833,000 lb/hr at 1300 psig, 750°F.
- (3) PG&E cogeneration plant in East Cat Canyon Field sells electricity and steam for field operation, assumed 10% pressure drop and 10% thermal losses.
- (4) PG&E purchases heavy crude oil from Husky Oil.

- (5) A fuel processing unit (partial oxidation) was used to clean the crude oil, efficiency = 60%.
- (6) Displaced energy computations assume $\eta_{tra I} = \eta_{tra II}$
- (7) 365 operating days per year.

Kaiser Steel

- (1) Peak electrical demand = 116 MWe, load factor = 90%
Average electrical demand = $116 \times 0.9 = 104$ MWe
- (2) Electric use = 60×10^6 kWh/mo maximum condition
- (3) Total steam demand from 7 boilers = 950,000 lb/hr
Blast furnace gas (BFG) provides 30% = 285,000 lb/hr
Steam provided from purchased fuels = 665,000 lb/hr
- (4) Steam assumed at .175 psig, saturated condition
- (5) Alternate G used for cogeneration system
Two boilers at 500,000 lb/hr each = 1×10^6 lb/hr
Assumed 95% load factor
Boiler steam = 950,000 lb/hr, 1450 psig, saturated superheater between boiler and steam turbine, $\eta_{st} = 80\%$; back pressure turbine $\eta = 80\%$, isentropic expansion
Feedwater = 60°F
Assumed 85% of total fuel required is provided by blast furnace gas
- (6) Equivalent number of operating days = 60×10^6 kWh/mo \times $1/104$ MWe \times 12 mo/24 hr = 288 days/year.

Kelco

- (1) Electric demand: Avg. = 6.0 MWe, Avg. monthly = 4.4×10^6 kWh/mo
- (2) Operating days = 4.4×10^6 kWh/mo \times $1/6.0$ MWe \times 12 mo/24 hr = 365 days/yr
- (3) Gas turbine system, $\eta = 2.7\%$; used Kelco's Plan II
Steam demand = 150,000 lb/hr, 125 psig, saturated waste heat boiler $\eta = 75\%$
- (4) Displaced energy computations assume $\eta_{tra I} = \eta_{tra II}$
- (5) Back pressure steam turbine, $\eta = 80\%$; used Kelco's Plan III
Feedwater = 60°F, boiler steam = 240 psig, sat; 150,000 lb/hr

Isentropic expansion in turbine

Turbine exhaust heated to saturation condition, 100 psig

Owens-Illinois

(1) Peak electrical demand = 13.9 MWe (1976 figures)

Avg. electrical usage = 90×10^6 kWh/yr

$$\text{Avg. elec. demand} = 90 \times 10^6 \frac{\text{kWh}}{\text{yr}} \times \frac{1}{320 \frac{\text{d}}{\text{yr}}} \times \frac{1}{24 \text{ hr}} \times \frac{1}{1000 \frac{\text{kW}}{\text{MWe}}} =$$

11.7 MWe

Steam demand = 0

(2) Natural gas used to fire five kilns

Annual consumption = 2.62×10^9 ft³/yr

Heat value of natural gas = 1025 Btu/ft³

$$\text{Natural gas used} = 2.62 \times 10^9 \frac{\text{cf}}{\text{yr}} \times 1025 \frac{\text{Btu}}{\text{ft}^3} \times \frac{1}{320 \frac{\text{d}}{\text{yr}}} \times \frac{1}{24 \text{ h}} =$$

$420 \times 10^6 \frac{\text{Btu}}{\text{hr}}$

(3) Condensing steam turbine, $\eta = 80\%$

Counter flow heat exchanger, $\eta = 60\%$

Furnace exhaust = 15,000 SCFM/furnace, 1000°F, 15 psia

Standard air = 14 ft³/lb, 70°F, 14.7 psia

Furnace exhaust = $15,000 \times 60/14 = 64,300$ lb/hr per furnace

For five furnaces = 321,000 lb/hr (total)

Steam out of heat exchanger = 850 psig, saturated (527°F)

Temperature gradient in heat exchanger = 50°F

Waste heat temperature = $527 + 50 \doteq 580^\circ\text{F}$

Condensate = 90°F

Heat of furnace exhaust = $\dot{m} c_p \Delta T$

$$Q_F = 321,000 \times 0.26 \times 420 = 35 \times 10^6 \text{ Btu/hr}$$

Heat from exchanger in form of steam

$$Q_S = 35 \times 10^6 \times .60 = 21 \times 10^6 \text{ Btu/hr}$$

Work of turbine = $21 \times 10^6 \times 0.8 = 16.8 \times 10^6$ Btu/hr =
4.9 MWe

(4) Gas turbine with compressor, $\eta = 27\%$

Air-to-air heat exchanger, $\eta = 60\%$

Heat value of stack gases = 35×10^6 Btu/hr from previous steam turbine calculations.

- (5) 320 operating days per year.

Simpson Paper

- (1) Peak electrical demand = 19 MWe
Avg. electrical demand = 17 MWe (option I used)
- (2) Total steam demand = 240,000 lb/hr
Boiler #1, 2 and 3 = 112,000 lb/hr, 600 psig, 750°F
Recovery boiler = 128,000 lb/hr (black liquor)
- (3) Assumed black liquor (fuel used in recovery boiler) available in same quantity for cogeneration system.
- (4) Assumed all black liquor steam used within process and none available for cogeneration system.
- (5) Condensing, extraction steam turbine, $\eta = 73.6\%$
Total steam supplied to turbine = 300,000 lb/hr
Stage I extraction at 175 psig = 120,000 lb/hr sat.
Stage II extraction at 75 psig = 120,000 lb/hr sat.
Condensate (assumed 80% load factor) 0.5 psig = 60,000 lb/hr, wet.
Plant's process steam = 240,000 lb/hr (does not include recovery boiler steam).
Isentropic expansion
- (6) Case where electrical demand is met (steam turbine system).
Work of turbine = $W_T \times \dot{m} = 17 \text{ MWe} \times 3.413 \times 10^6 = 58 \times 10^6 \text{ Btu/hr}$
 $\dot{m} = 58 \times 10^6 \text{ Btu/hr} / 355 \text{ Btu/hr} = 163,440 \text{ lb/hr} > 112,000 \text{ lb/hr}$
No additional steam required.
- (7) Equivalent number of operating days = $12 \times 10^6 \text{ kWh/mo} \times 1/17 \text{ MWe} \times 12 \text{ mo}/24 \text{ hrs} = 353 \text{ days/yr}$

Simpson Timber

- (1) Korbell saw mill was selected for analysis.
- (2) Average electrical demand = 4.4 MWe
- (3) Avg. electrical usage = $4.4 \text{ MWe} \times 24 \text{ hr} \times 238 \text{ d}/12 \text{ mo} \times 1000 = 2.1 \times 10^6 \text{ kWh/mo}$
Site report states $5.5 \times 10^6 \text{ kWh/mo} \neq 2.1 \times 10^6 \text{ kWh/mo}$ (latter number used in calculations).

- (4) Maximum boiler capacity = 15,000 lb/hr
- (5) Boiler operates at 50% capacity
- (6) Steam demand = 7500 lb/hr, 15 psig, saturated
- (7) Back pressure steam turbine, $\eta = 80\%$
 Process steam = 7500 lb/hr, 30 psia, wet
 Assumed boiler outlet steam = 600 psig, 750°F
- (8) No. of operating days = 238 days/yr

Spreckels Sugar

- (1) Existing cogeneration system
- (2) Plant electrical demand = 5.0 MWe
 Existing cogeneration = 4.2 MWe
 Purchased power = 0.8 MWe
- (3) Total steam demand = 220,000 lb/hr
 For shaft work in plant = 81,000 lb/hr
 Cogeneration steam = 139,000 lb/hr
- (4) Assumed only cogeneration steam of 139,000 lb/hr was used;
 plant's shaft work steam not included in analysis.
- (5) Back pressure turbine, $\eta = 80\%$
 Process steam = 139,000 lb/hr, 105 psia, wet
 Boiler outlet steam = 400 psig, 600°F
 Feedwater = 60°F
- (6) No plant expansion anticipated, therefore net energy savings was
 not computed.
- (7) Operating days = 300 days/yr

Union Oil

- (1) Electrical demand = 50 MWe
- (2) Steam demand = 625,000 lb/hr, 700°F, 450 psig
- (3) Cogeneration achieved by updating existing equipment and
 utilizing refinery fuel gas; thus 40 MWe of cogenerated power
 is obtainable without additional purchased fuel.
- (4) Fluid Cat Cracker will expand 450 psig steam to 25 psig through
 a steam turbine producing 20 MWe.

- (5) Catalytic reforming unit generates low Btu CO flue gas and will fire a gas turbine for an additional 20 MWe.
- (6) Cogenerated power uses no additional energy.
- (7) 365 operating days per year.

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GLOSSARY

This glossary contains a list of terms frequently used in discussions of cogeneration. The selection of terms was based on experience with the relevant literature. Sources for the terms are contained in the Bibliography.

APCD

Air Pollution Control District

AQMA

Air Quality Maintenance Area

ARB

Air Resources Board

Base Load

The minimum load of electric power which is generated or supplied continuously over a period of time.

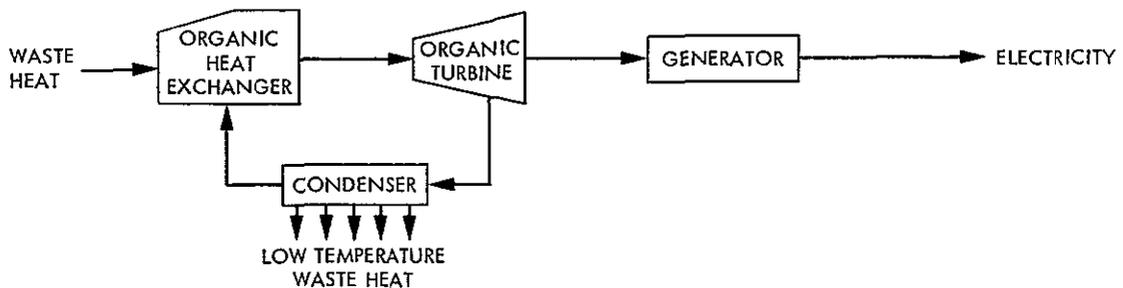
Bottoming cycle

Waste heat from an industrial process is utilized for the generation of electricity.

Bottoming cycle, combined/organic

Waste heat from a gas/steam turbine is utilized for the generation of electricity in an organic bottoming cycle.

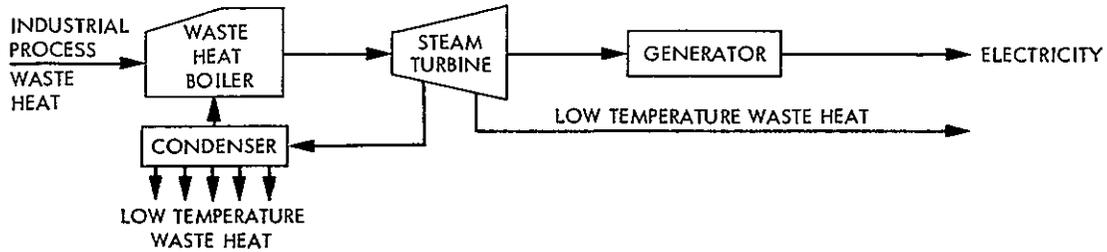
Bottoming cycle, organic



The utilization of low temperature waste heat from an industrial process for the generation of electricity in a system using an organic working fluid.

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Bottoming cycle, steam



The utilization of waste heat from an industrial process for the generation of electricity using a steam turbine.

Brayton cycle

A reversible thermodynamic cycle which describes the heat to work conversion process in a gas turbine power plant.

By-product power

Power which is generated in conjunction with an industrial process which optimizes or matches the generation of electricity to the steam and/or heat requirements.

Capacity

The load for which a generating unit, generating station, or other electrical apparatus is rated either by the user or by the manufacturer.

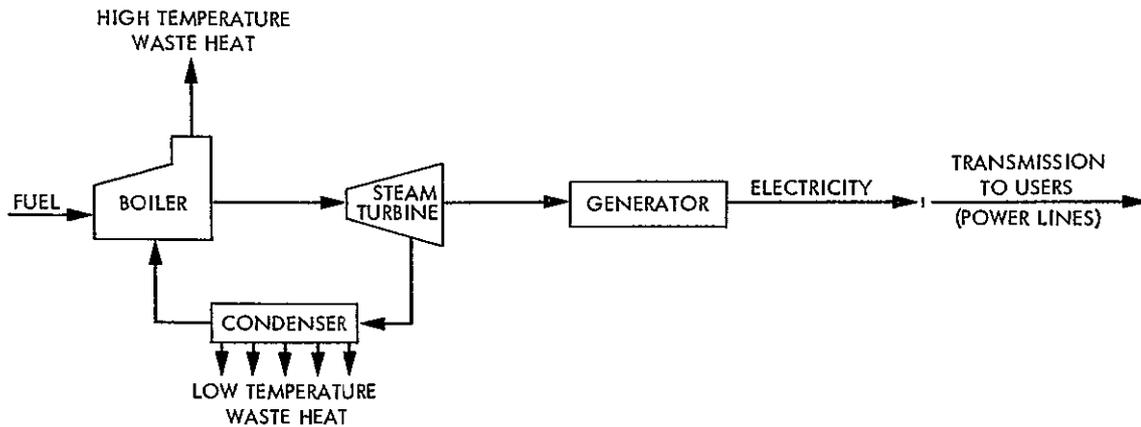
Capacity factor

The ratio of the average load on a machine or equipment for the period of time considered to the capacity rating of the machine or equipment.

Capital cost

Cost of construction of new plant (additions, betterments, and replacements) and expenditures for the purchase or acquisition of existing facilities.

Central power generation, steam



Electricity generated by a utility at a large power generating plant, the primary purpose of which is the generation of electricity.

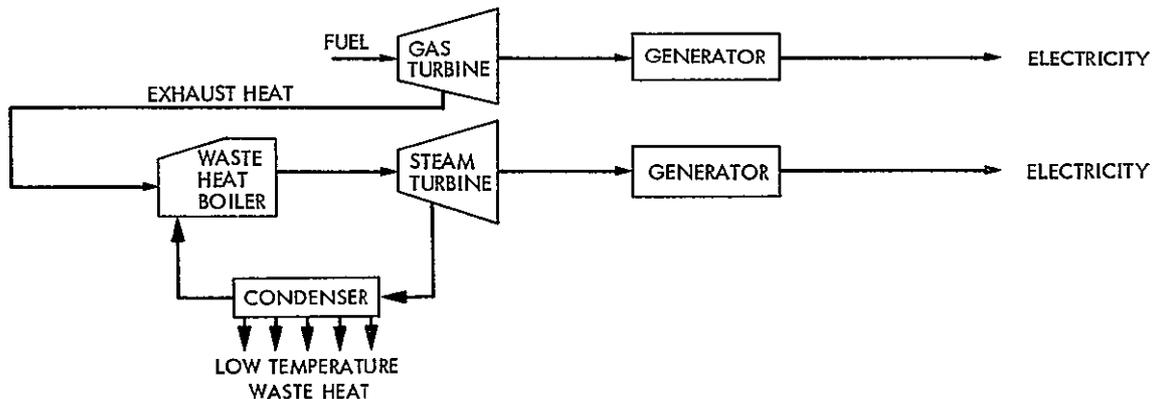
CERCDC

California Energy Resources Conservation and Development Commission

Cogeneration

The generation of process steam, process heat or space conditioning combined with the generation of electrical power which leads to an efficiency of fuel utilization greater than that resulting from the independent generation of equivalent units of process steam, process heat, space conditioning, and electrical power.

Combined cycle



Waste heat from a gas turbine topping cycle is utilized for the generation of electricity in a steam turbine/generator system.

Condensing power

Power generated through a final steam turbine stage where the steam is exhausted into a condenser and cooled to a liquid to be recycled back into a boiler.

CPUC

California Public Utilities Commission

Dual-purpose power plant

See cogeneration.

Engine topping

See topping cycle.

Feedstock

With respect to cogeneration, it is the type of fuel supply to a combustion process for the production of heat used for energy conversion to steam or electricity.

Field assembled boiler

A high pressure boiler which usually has a large capacity. Generally oil and gas fired, it can also burn solid fuels and costs about \$40-45/lb of steam per hour.

Fuel allocation

Natural gas is allocated by the priority basis consistent with defined end-uses. Priorities, from a high of P1 to a low of P5, are effective May 31, 1976.

Grid

A utility's power generation, transmission and distribution system, including transmission lines, transformer stations, etc.

Heat rate

A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting net kilowatt-hour generation.

Heat recuperators

Equipment used to recycle heat back into the process creating a higher thermal efficiency of the overall process.

High grade waste heat

Waste heat in the high temperature range of 1000°F or above which can be used for power generation in a steam turbine.

Hog fuel

A waste product of the lumber industry consisting of coarse residue and sawdust which can be used as by-product fuel.

Industrial cogeneration

Power generation at an industrial site using either a topping cycle or a bottoming cycle.

Industrial dual-purpose power plant

See industrial cogeneration.

Industrial steam

Steam that is produced as part of the industrial process.

In-plant generation

See industrial cogeneration.

Internal rate of return

The discount rate which equates the present value of expected future receipts to the cost of the investment outlay.

Interruptible power

Power made available under agreements which permit curtailment or cessation of delivery by the supplier. Advance notice is usually given from 1 to 1-1/2 hours prior to the interrupt.

Investment tax credit

A specified percentage of the dollar amount of new investment in each of certain categories of assets that a firm can deduct as a credit against their income tax bill.

Load

The amount of electric power delivered or required at any specified point or points on a system. Load originates primarily at the power-consuming equipment of the customers.

Load factor

The ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load occurring in that period.

Low grade waste heat

Waste heat in the temperature range of less than 1000°F.

Megawatt (MWe)

One thousand kilowatts of electric power.

Net present value

A capital budgeting method which takes into account the time value of money through discounted cash flow analysis. The method determines the present value of the expected net revenue from an investment minus the cost outlay, discounted at the cost of capital.

New Source Review Rules

Adopted by the California Air Resources Board, these rules constitute a set of guidelines to be used by state and pollution control officers when ruling on permits to construct new stationary sources or modifications to existing stationary sources.

Operating cost

A group of expenses applicable to operations.

Package boilers

A low pressure boiler, usually small enough to be shop assembled. It generally burns gas or liquid fuels and costs about \$10/lb of steam per-hour.

Parallel generation

Industrial power generation facilities whose AC frequencies are exactly equal to and operate in synchronism with the utility service grid.

Payback period

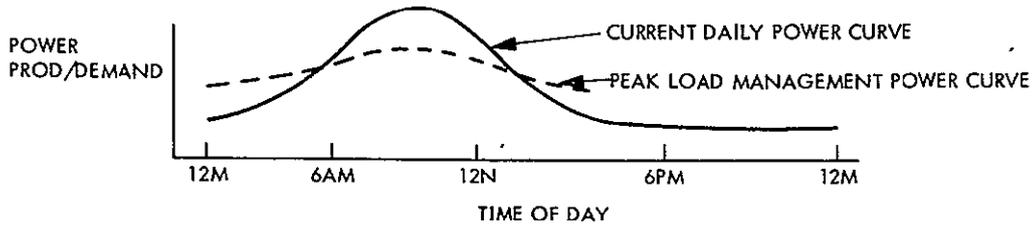
The number of years required for a firm to recover the original investment from net returns before depreciation but after taxes.

Peak load

The maximum of all demands of the load which has occurred during a specified period of time.

Peak load management

An attempt to reduce the system peak load by leveling the daily power curve.



Power factor

The ratio of real power to apparent power for any given load and time. Generally, it is expressed as a ratio.

Preheaters

Equipment used to pre-heat the intake air prior to entering a combustion process creating a higher thermal efficiency for the overall process.

Present value

The present value of a cash flow is its real value adjusted for the interest that could be earned, or must be paid, between the time of the actual flow and the specified "present" time.

Process heat

Heat used for the industrial process of a plant and not the housekeeping chores such as space heating.

Process Steam

See industrial steam.

Process steam load

Number of pounds of steam per hour required for a specified industrial process.

Rankine cycle

A reversible thermodynamic cycle which describes the heat to work conversion process in a steam power plant.

Rate base

The value of assets, established by a regulatory authority, upon which a utility is permitted to earn a specified rate of return. Generally, this represents the amount of property used and useful in public service.

Sinking fund

Cash or other assets, and the interest or other income earned thereon, set apart for the retirement of a debt, the redemption of a stock, or the protection of an investment in depreciable property.

Spinning Reserve

Generating capacity which is on-line and ready to take load, but in excess of the current load on the system.

Standby power

See standby service.

Standby reserve

See standby service .

Standby service

Service that is not normally used but which is available through a permanent connection in lieu of, or as a supplement to, the usual source of supply.

Sunk costs

Costs which have already been committed and thus are irrelevant to future investment decisions.

Surplus electricity

Energy generated that is beyond the immediate needs of the producing system. This energy is frequently obtained from spinning reserve and sold on an interruptible basis.

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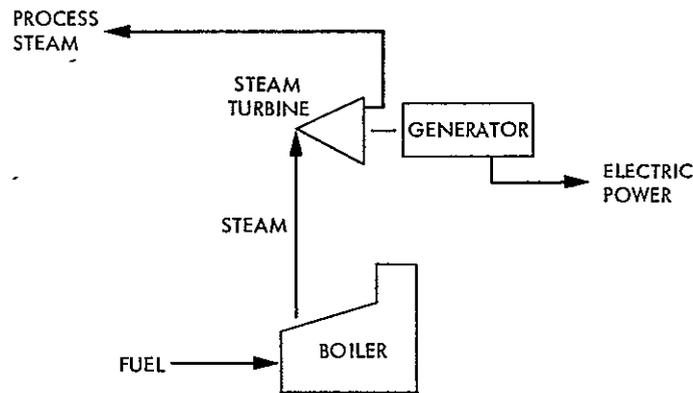
Thermally integrated energy system (TIES)

The electric power output of the local power generation plant goes into the utility company distribution grid, rather than directly to the user. The user is served power from the grid but also receives heating and cooling media produced from power generation by-product heat from the TIES plant.

Topping cycle

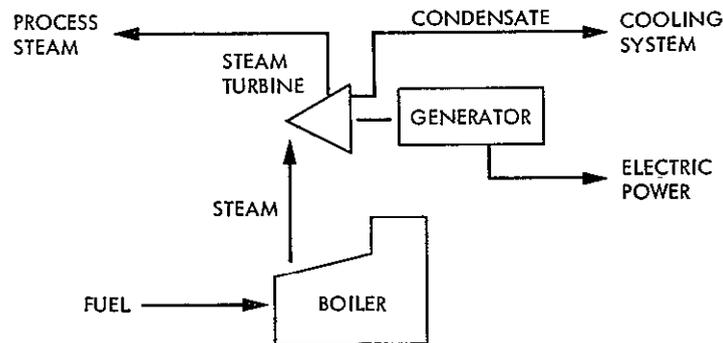
Energy is first used to generate electricity then used in an industrial process.

Topping cycle, back-pressure steam turbine



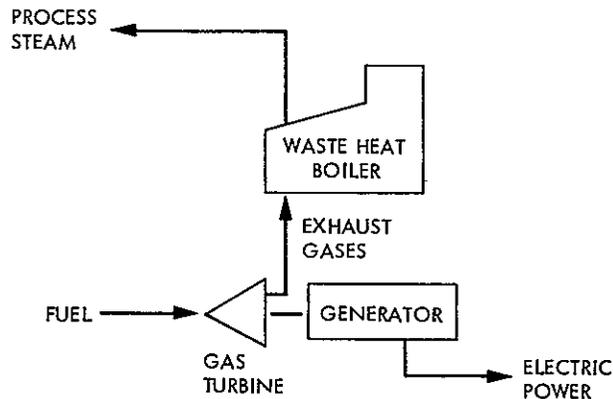
Steam is generated in a boiler then sent through a turbine-generator, producing electricity. The steam is discharged from the last stage of the turbine at pressures needed for industrial process use.

Topping cycle, extraction steam turbine



This system operates in a similar manner to the back-pressure steam turbine, except that steam is extracted at different pressures from intermediate stages of the turbine and used in industrial processes, while the steam exhausting from the final stage is condensed and returned to the boiler for reuse.

Topping cycle, gas turbine/waste heat boilers



Compressed air and a gaseous fuel or light petroleum product are fired in a gas turbine. The hot combustion gases pass through a turbine-generator, producing electricity. The hot exhaust gases from the turbine are passed over water-filled tubes in a waste-heat boiler, producing steam at pressures needed for industrial process use.

Total energy system

On-site generation of electricity with beneficial use of waste heat.

Turbine

An enclosed rotary type of prime mover in which heat energy in steam or gas is converted into mechanical energy by the force of a high velocity flow of steam or gases directed against successive rows of radial blades fastened to a central shaft.

Utility cogeneration

Utilization of waste heat from a central power generating plant to produce either thermal energy to sell for space or process heat, or additional electrical energy.

Utility dual-purpose power plant

See utility cogeneration.

Waste heat

Unused thermal energy which is exhausted to the environment from an electric generation system or an industrial process.

Wheeling

The use of the transmission facilities of one system to transmit power of and for another system.

Wheeling charges

Cost of wheeling power.

Working capital

The amount of cash or other liquid assets that a company must have on hand to meet the current costs of operations until such a time as it is reimbursed by its customers.

