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USE OF GEOTHERMAL HEAT FOR SUGAR REFINING

FINAL REPORT
FOR PERIOD OCTOBER 1, 1976 – MAY 31, 1977

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ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
DIVISION OF GEOTHERMAL ENERGY

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SUMMARY

The objective of this study was to assess the economic and technical feasibility of applying low grade geothermal heat (<300°F) in the beet sugar refining industry for both new factory construction and retrofit conversion of existing factories. The representative Holly Sugar factory at Brawley, California was utilized as a baseline primarily because of its centralized location with respect to the known and partially developed geothermal anomalies at Brawley, East Mesa and Heber. Nominal values for the key parameters of the sugar refining process and typical values for the geothermal fluid parameters representative of geothermal resources in areas of existing or potential future sugar factories were defined, promising points of application were identified and conceptual designs synthesized for introducing the geothermal heat into the process. The design approaches were then quantified with capital, operating and maintenance costs and comparative economic evaluations were made with other fuels projected to 1995.

In parallel with the detailed study of process conversion to geothermal heat, the existing pattern and potential growth of the sugar refining industry was assessed to estimate the potential market for new factory construction at suitable areas as well as the potential for retrofit conversion of existing factories. The environmental impact of other geothermal application concepts was also assessed and expected technological or industry/government policy changes which might affect the potential for conversion to geothermal heat were identified and evaluated.

Emphasis was placed on achieving results that would stimulate commercial utilization of geothermal heat for beet sugar refining and related processes. Major areas of concern were solicited from beet sugar industry representatives and plans were formulated for demonstration technology developments to resolve engineering and economic uncertainties identified in the process conversion analyses and the expressed concerns of industry. The demonstration critical components and subscale process equipment are defined with supporting test hardware required for testing at the ERDA East Mesa Geothermal Component Test Facility located approximately 18 miles from the Holly Sugar factory at Brawley.

Conclusions

The overall conclusion is that it is technically and economically feasible to utilize 300°F geothermal fluids in a beet sugar factory based on modifications to existing process engineering concepts. A summary of study conclusions, supporting this overall conclusion, is as follows:

(a) The technical feasibility of using 300°F (150°C) geothermal fluids in the beet sugar refining process has been determined. Promising points of application are identified as follows:

   (1) Conventionally throttled process medium pressure (25 to 30 psig) make-up steam could be retrofitted in an existing factory with geothermally generated steam, resulting in 15 to 35% savings in fossil fuel demands.

   (2) New factories could utilize evaporators designed for 100% of 25 psig geothermally generated steam supply.

   (3) Beet pulp drying could be accomplished using geothermal fluids directly and appear to offer the greatest opportunity for fossil fuel savings in that 30 to 50% of a total sugar factory fuel demand is used for drying.

   (4) Nominally 100 tons of refrigeration is required for crystallized and bulk sugar cooling which could be provided with geothermally fired absorption cooling. This process could provide beneficial cascaded utilization of process or bulk drying geothermal effluents.

(b) Thirty-five of the fifty-five United States sugar beet factories are located in the eleven western states where Hydrothermal resources are located. Eleven of these factories are located within 100 miles of potential geothermal resources of 300°F or greater. The resource areas identified in order of their estimated potential are as follows:

   (1) Imperial Valley, California

   (2) Southwest Idaho and adjacent parts of Oregon

(3) Southeast Idaho and adjacent parts of Utah

(4) Northern California

(5) Southern California

(6) Central Washington

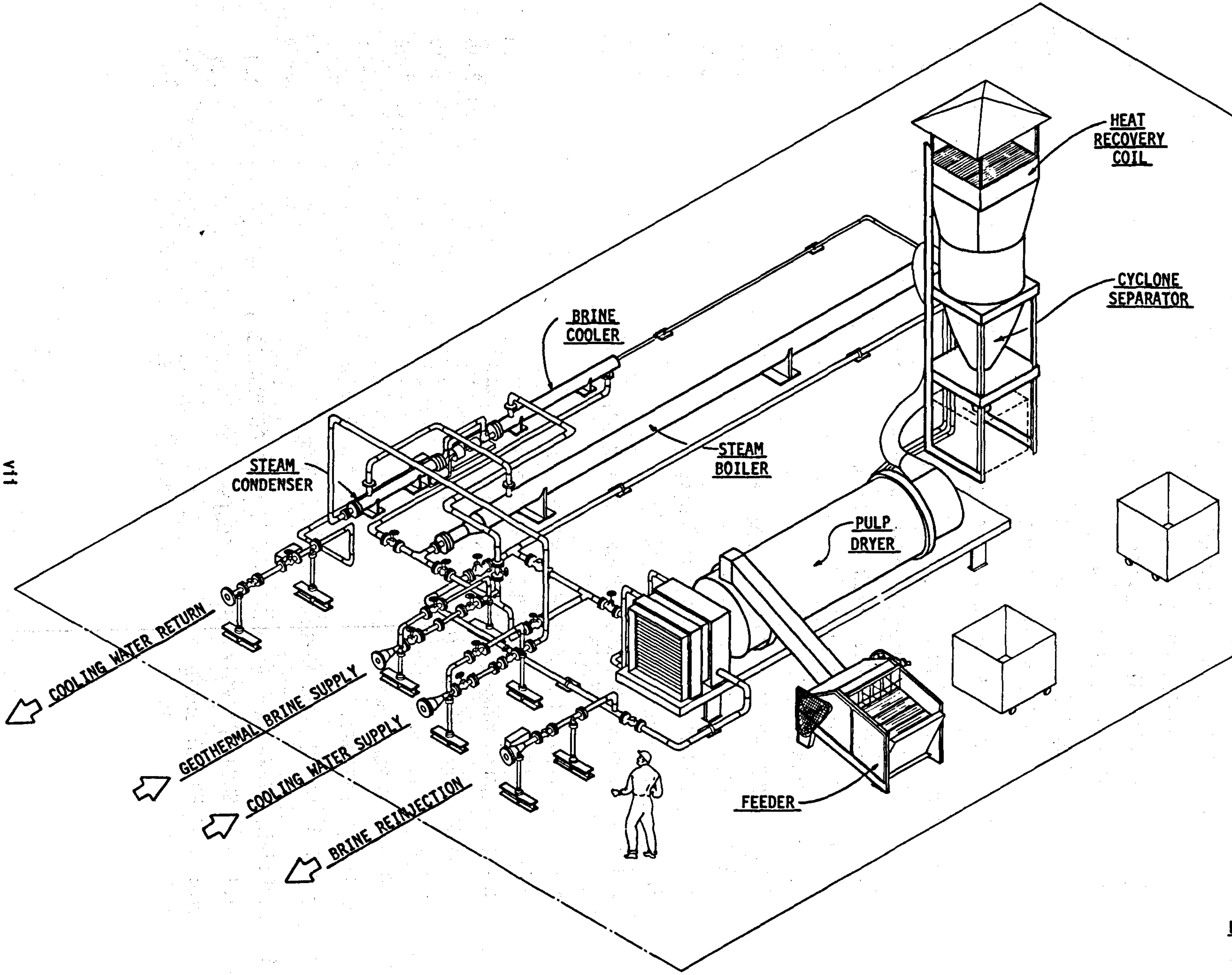
(c) Economic evaluations indicate geothermal energy supply costs are competitive with fossil fuels for sugar factory cascade system and balanced season applications: e.g., cost estimates based on a conceptually designed retrofit at the Holly/Brawley factory providing cascaded boiler and beet dryer operation with off season alfalfa drying, using the same dryers, indicates attractively competitive geothermal energy application costs of $1.73 as compared with 1976 fuel oil costs of $2.23 per million BTU's.

(d) A feasible accelerated development schedule for geothermal application to sugar refining was developed using the Holly/Brawley plant as a retrofit model. It appears that a retrofitted plant could start operation as early as the second quarter of 1980 considering sugar campaign time periods, technology developments, equipment and reservoir development lead times, if the test equipment designs were complete enough to order long lead items in October of this year. If the October date is missed the earliest estimated operation would slip one year to second quarter 1981 as explained in Section 11.

(e) There is little likelihood of any new beet sugar factories being built, near term, because without sugar legislation the sugar price is not high enough or stable enough to project return on investment. However, the factories are energy intensive and with projected rising fossil fuel costs factory operators have expressed an interest in retrofitting in areas where factories now exist and geothermal energy is readily available.

(f) Based on the study evaluations of retrofit potential at the Brawley factory and the 7 potential factories identified, a fossil fuel savings of approximately 1,606,000 barrels of oil equivalent per year is projected with sugar factories retrofitted to utilize geothermal energy. It is noted, however, that the total savings would be in excess of 3,000,000 barrels equivalent per year if off season uses, such as alfalfa drying, were utilized as well.

(g) Representatives from the beet sugar refining industry indicated that there is a need for geothermal demonstration technology experiments to resolve engineering and economic uncertainties identified in this study. The sugar manufacturers contacted by TRW indicated they would require satisfactory sub-scale demonstration before proceeding with plans for retrofitting of a new plant. A demonstration experiment sub-scale configuration of the cascaded application satisfying these expressed needs is illustrated in Figure 1 and described in Section 11.



ERDA EAST MESA
GEOTHERMAL COMPONENT
TEST FACILITY

FIGURE I
CASCADED BOILER/DRYER
DEMONSTRATION EXPERIMENT

CONTENTS

CONTENTS (Continued)

CONTENTS (Continued)

LIST OF FIGURES

LIST OF FIGURES
CONTINUED

LIST OF TABLES

LIST OF TABLES
CONTINUED

1. BASELINE SUGAR REFINING PROCESS DESCRIPTION

The study objective is to assess the potential for use of geothermal heat in the sugar refining industry for both new factory construction and retrofit conversion of existing factories. In keeping with the objective, we have selected the Holly Sugar factory at Brawley, California as the baseline for initial analyses since the factory is:

a. Typically representative of the composite North American beet-sugar factory flow diagram as displayed and described in "Beet Sugar Technology," Beet Sugar Foundation, Second Edition, 1971.

b. Located near the Brawley KGRA (see Figure 1-1), which makes it a prime candidate as a demonstration plant for future retrofit conversion to geothermal energy. The Brawley KGRA contains tested production wells within 8 miles of the plant. Exploratory wells are also being planned for mid-1977 completion within one mile of the plant, pending approval of a geothermal loan guaranty application to ERDA..

c. Located within 20 miles of the Heber and East Mesa KGRA's (see Figure 1-1), which have sufficient reservoir definition to be considered for new or moved factory locations. Each of these KGRA's has 10 or more flowing wells for which abundant data on geothermal fluid characteristics is available.

d. Located approximately 14 miles from the ERDA East Mesa Geothermal Component Test Facility, which could be used for preliminary demonstration experiments prior to retrofit of the Brawley factory or new factory locations in the area.

The Holly Brawley factory is a multimillion dollar facility which processes nominally 6,000 tons of sugar beets per day. The plant produces approximately 1,050,000 pounds of high-purity sugar per day, which is shipped as granulated sugar in bulk or packaged form. Figure 1-2 is an aerial view of the Brawley factory with locaters on the main elements for subsequent discussion reference.

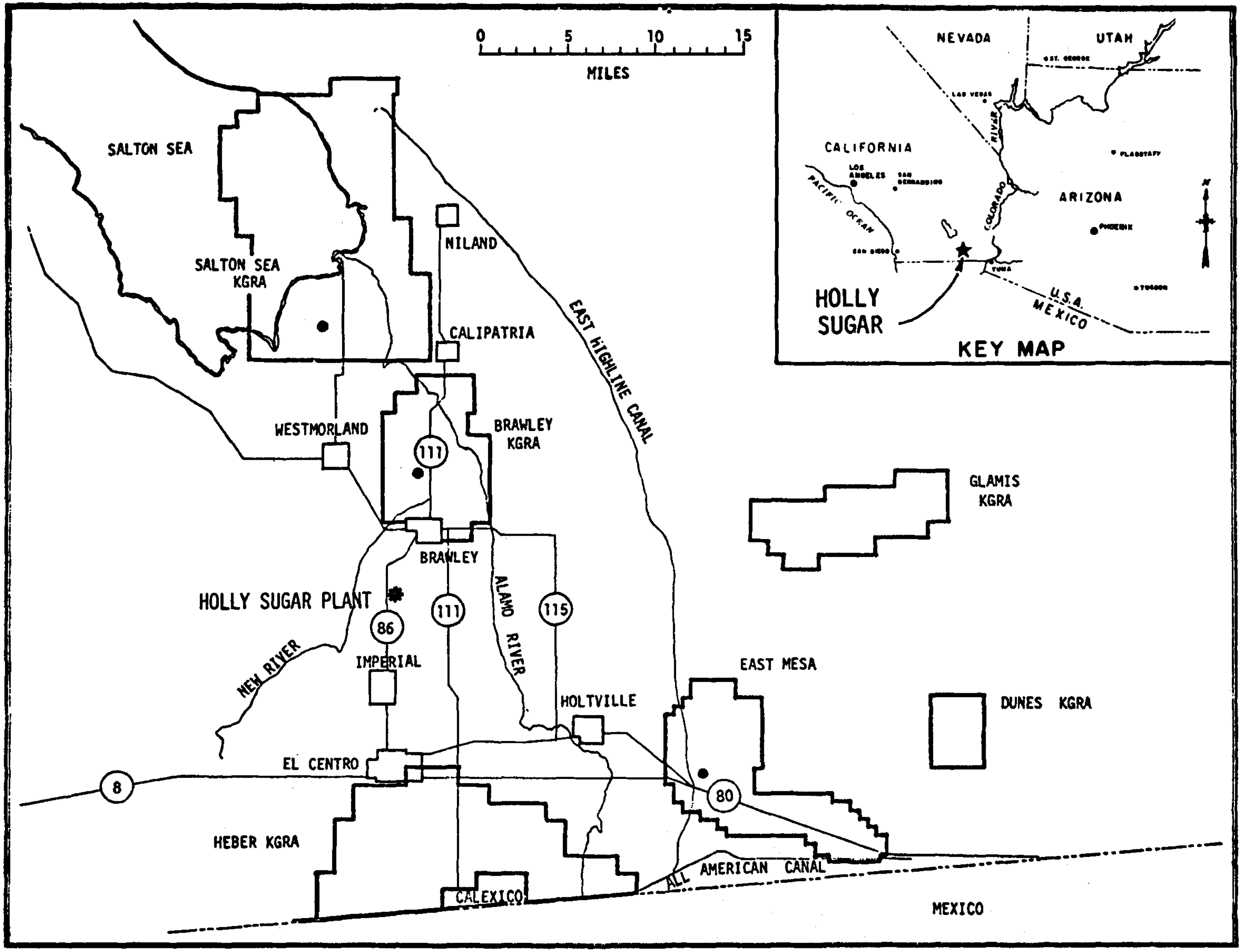


FIGURE 1-1. MAP SHOWING HOLLY SUGAR PLANT AT BRAWLEY AND NEARBY KGRA's

(KGRA's from USGS Geothermal Land Classification Map 1975)

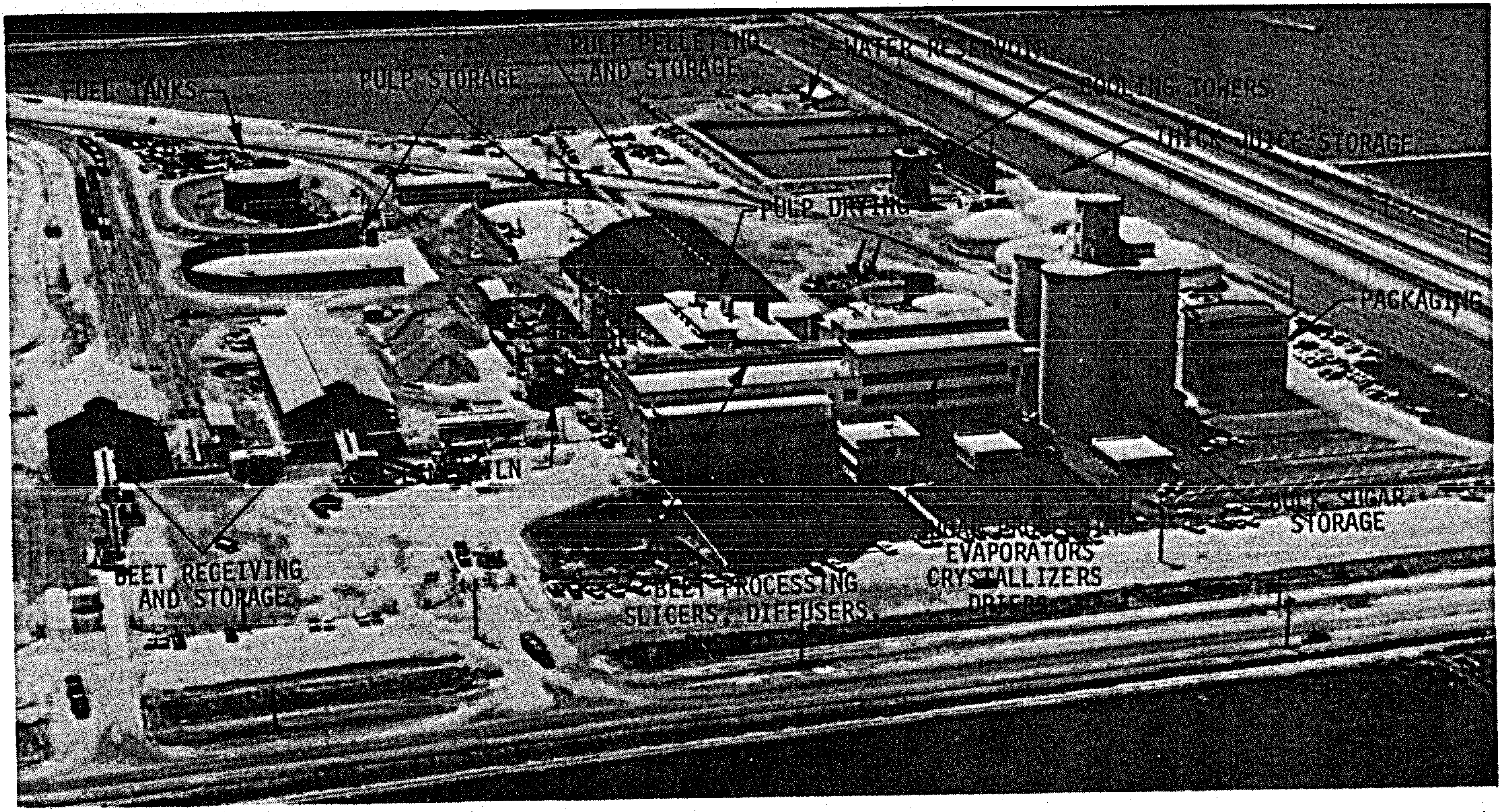


Figure 1-2. Aerial View of Holly Sugar Plant at Brawley, California

In 1976, the Brawley factory campaign (operation) was from April 2 through September 22. The factory is designed to slice a larger tonnage of beets than on-line capability to process; therefore, excess thick juices are stored for late processing; i.e., April 2 to August 5 for beet slicing and processing and August 5 to September 22 for refining of stored thick juices. It is noted that beet piling is limited to 20 hours duration under shade in Arizona and California. In the northwest, beets can be stored an average of 90 days; therefore, stored beets are utilized to smooth the factory flow, which for maximum economy, operates as close to capacity as possible at all times.

1.1 Beet-Sugar Process Description

Extraction of sugar and the by-product dried beet pulp from sugar beets is an energy intensive process with approximately 14% of product cost attributable to fuel costs. Figure 1-3 indicates the study developed process flow diagram for the baseline factory at Brawley. Figure 1-4 presents a simplified schematic of the manufacturing process flow integrated with the balanced boiler live steam, turbine exhaust steam and evaporator vapor transmission of heat to various portions of the process. As an introduction to the reader unfamiliar with the industry, the process may be conveniently separated into stages as illustrated in Figure 1-4 and described as follows:

a. Diffusion Stage. Sugar beet roots are thoroughly washed in preparation for slicing and transported by flume from the receiving yard to the slicers. The beets are sliced into thin strips called cossettes. The slicers require live steam at 150 PSIG, minimum, for blade cleaning. The cossettes are then immersed in hot water, leaching out the sugar by diffusion. The temperature is raised for better extraction using vapors formed in the second evaporator effect.

b. Juice Purification Stage. The raw diffusion juice is screened to remove any small particles of cossettes, and then heated to 175-185°F using vapors formed in the third evaporator effect. The heated raw juice is then purified by a process called carbonation in which lime and carbon dioxide gas are added to precipitate the impurities in the juice. Filtration and settling remove the solid particles and eliminate impurities. The purified liquid is called thin juice and contains 10 to 15% sugar solids.

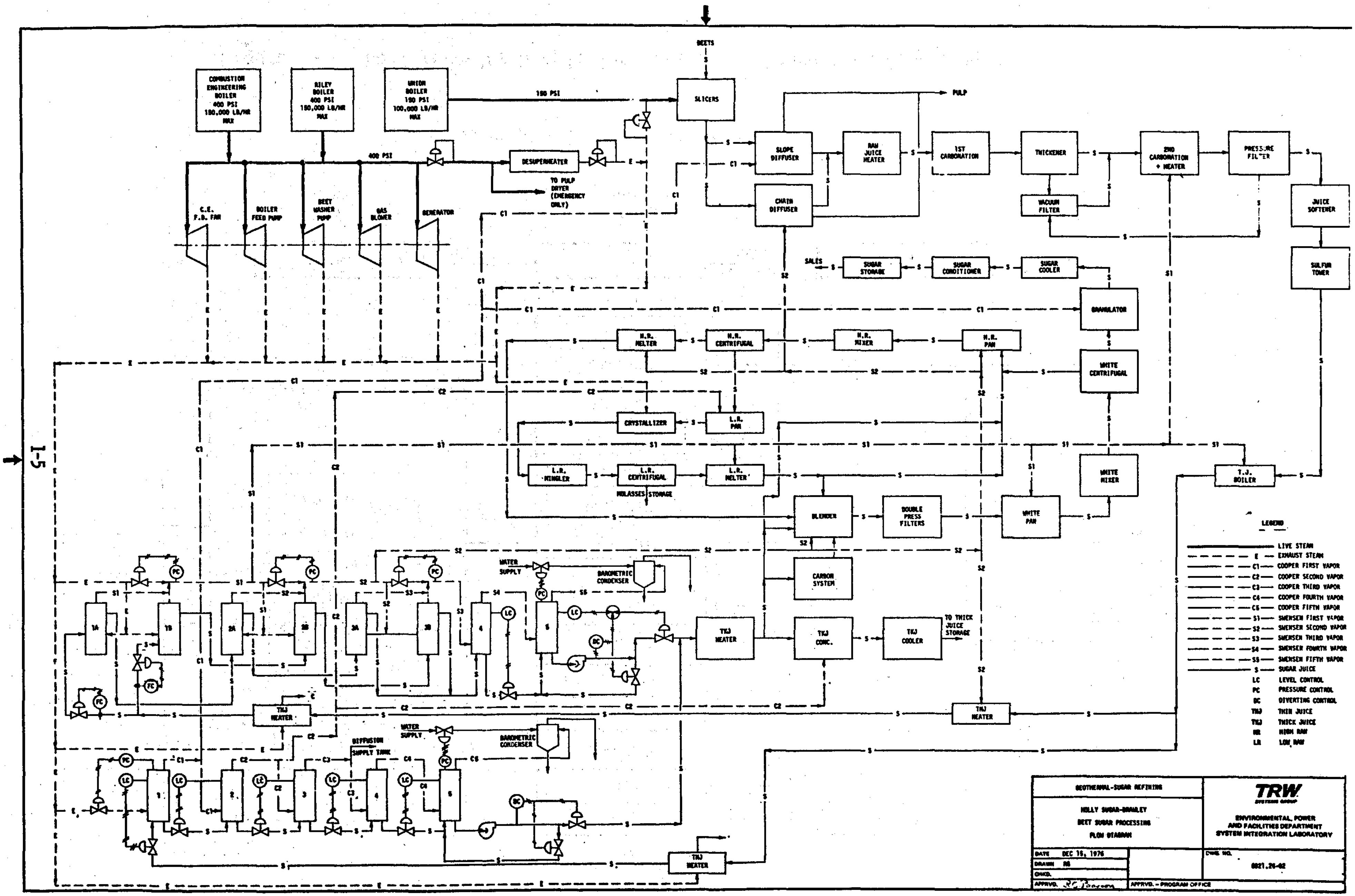

BEETS
COMBUSTION ENGINEERING BOILER 400 PSI 180,000 LB/HR MAX
RILEY BOILER 400 PSI 150,000 LB/HR MAX
UNION BOILER 150 PSI 100,000 LB/HR MAX
150 PSI
400 PSI
SLICERS
PULP
DESUPERHEATER
TO PULP DRYER (EMERGENCY ONLY)
C.E. F.D. FAN
BOILER FEED PUMP
BEET WASHER PUMP
GAS BLOWER
GENERATOR
SLOPE DIFFUSER
CHAIN DIFFUSER
RAW JUICE HEATER
1ST CARBONATION
THICKENER
VACUUM FILTER
2ND CARBONATION + HEATER
PRESSURE FILTER
JUICE SOFTENER
SULFUR TOWER
SALES
SUGAR STORAGE
SUGAR CONDITIONER
SUGAR COOLER
GRANULATOR
H.R. MELTER
H.R. CENTRIFUGAL
H.R. MIXER
H.R. PAN
WHITE CENTRIFUGAL
CRYSTALLIZER
L.R. PAN
L.R. MINGLER
L.R. CENTRIFUGAL
L.R. MELTER
MOLASSES STORAGE
WHITE MIXER
T.J. BOILER
BLENDER
DOUBLE PRESS FILTERS
WHITE PAN
CARBON SYSTEM
WATER SUPPLY
BAROMETRIC CONDENSER
TKJ HEATER
TKJ CONC.
TKJ COOLER
TO THICK JUICE STORAGE
THJ HEATER
DIFFUSION SUPPLY TANK
LEGEND
LIVE STEAM
E EXHAUST STEAM
C1 COOPER FIRST VAPOR
C2 COOPER SECOND VAPOR
C3 COOPER THIRD VAPOR
C4 COOPER FOURTH VAPOR
C5 COOPER FIFTH VAPOR
S1 SWENSEN FIRST VAPOR
S2 SWENSEN SECOND VAPOR
S3 SWENSEN THIRD VAPOR
S4 SWENSEN FOURTH VAPOR
S5 SWENSEN FIFTH VAPOR
S SUGAR JUICE
LC LEVEL CONTROL
PC PRESSURE CONTROL
DC DIVERTING CONTROL
THJ THIN JUICE
TKJ THICK JUICE
HR HIGH RAW
LR LOW RAW
GEOTHERMAL-SUGAR REFINING
HOLLY SUGAR-BRAWLEY
BEET SUGAR PROCESSING
FLOW DIAGRAM
TRW
SYSTEMS GROUP
ENVIRONMENTAL, POWER AND FACILITIES DEPARTMENT
SYSTEM INTEGRATION LABORATORY
DATE DEC 15, 1976
DRAWN
CHKD.
APPRVD.
APPRVD. - PROGRAM OFFICE
DWG NO.

FIGURE 1-3

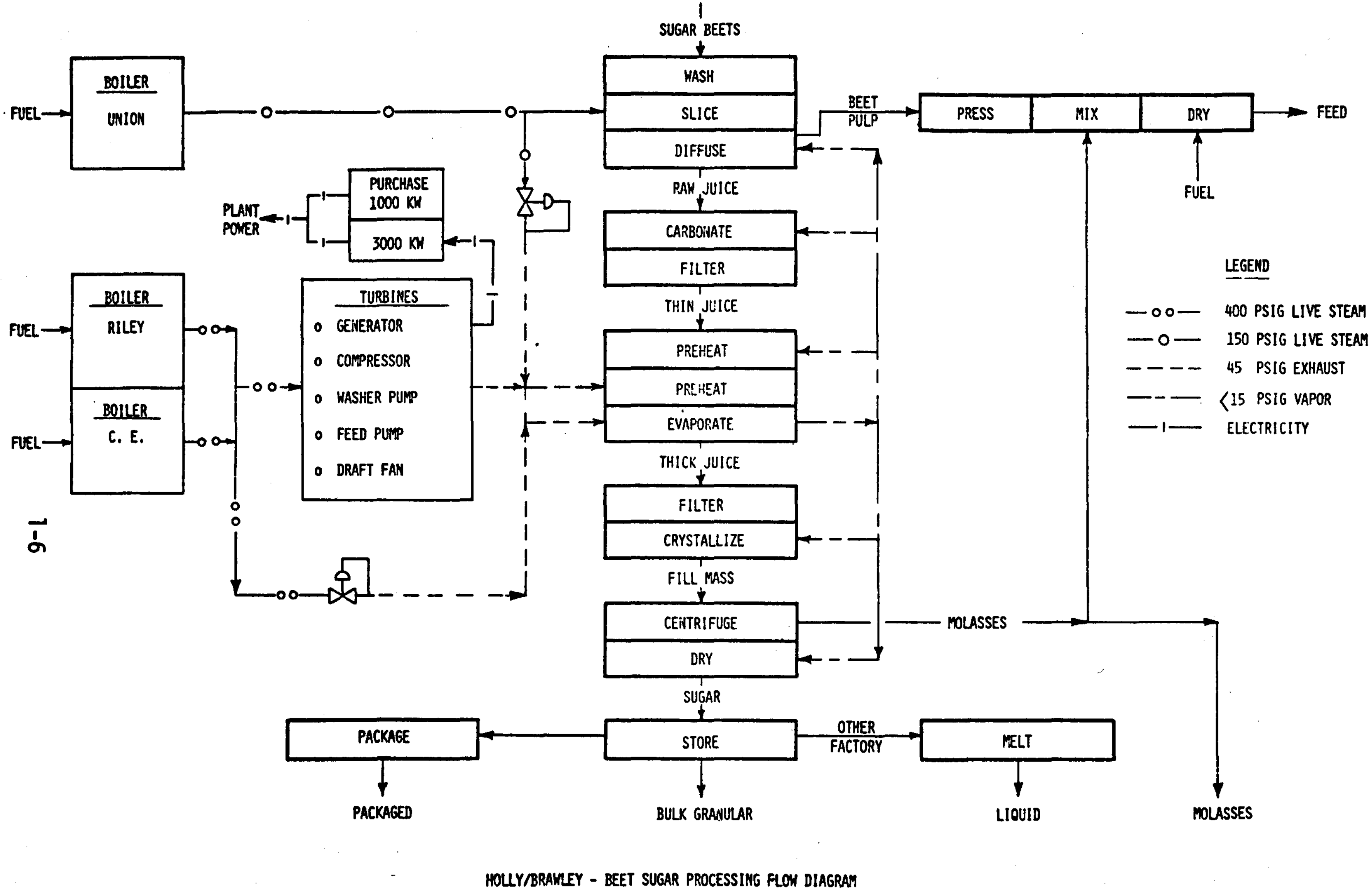


Figure 1-4. Holly/Brawley Simplified Beet Sugar Processing Flow Diagram

c. Evaporation State. The thin juice is then preheated using first and second vapors and exhaust steam and sent to the evaporators. The thin juice is concentrated by evaporation in multiple-effect evaporators, with five individual bodies or effects. The evaporators are arranged in a forward feed arrangement, with steam used for the first effect drawn from turbine exhausts, but for each succeeding effect the steam used is that formed in the preceding effect by evaporation of water from the juice. This system, developed by the beet-sugar industry is economical since it allows multiple use of the same heat energy and results in decreasing temperatures and pressures as the juice proceeds through the effects. The thick juice outflow is concentrated by evaporation to a dissolved sugar solid content of 50 to 65%.

d. Crystallization Stage. Further filtering insures that all solid particles are eliminated. The sugar is then crystallized by pan boiling in vacuum pans. Low temperature pan boiling heat is provided by second vapors to avoid carmelization. The resulting mixture of sugar crystals and liquid from the pans is known as fillmass. The fillmass is spun and washed in high-speed centrifugals to separate the sugar crystals from the liquid. The wet white sugar crystals are then sent to the dryer or granulator and from there to the cooler. The granulated sugar is then screened and either sacked immediately, or stored in bulk bins to await further packaging or bulk delivery.

e. Dryed-Pulp Manufacturing Stage. Wet pulp from the diffuser (a) is pressed in pulp presses to reduce the moisture content from 95 to 80%. The pressed pulp is then mixed with molasses, from the centrifuge (d) and dryed to a moisture content of about 10% by hot air in a pulp dryer. A conventional pulp dryer is direct-fired, with an induced-draft, parallel-flow, rotating-drum. The drum, approximately 12 feet in diameter by 60 feet long, contains baffles, which drop the pulp through the hot flue gases as the drum rotates. The pulp is moved through the drum by the flow of combustion gases as the drum rotates. The drums are normally gas-or oil-fired with products of combustion mixed with cooling gas to obtain a nominal entering temperature of 1200°F to prevent losses from pulp combustion. An induced draft fan is located at the drum discharge, flowing through a cyclone separator to recover small particles from the flue gases exiting at 230 to 280°F.

The fuel used in the pulp drying operation accounts for 30 to 50% of the total fuel required by the entire beet factory in its daily operation while slicing beets.

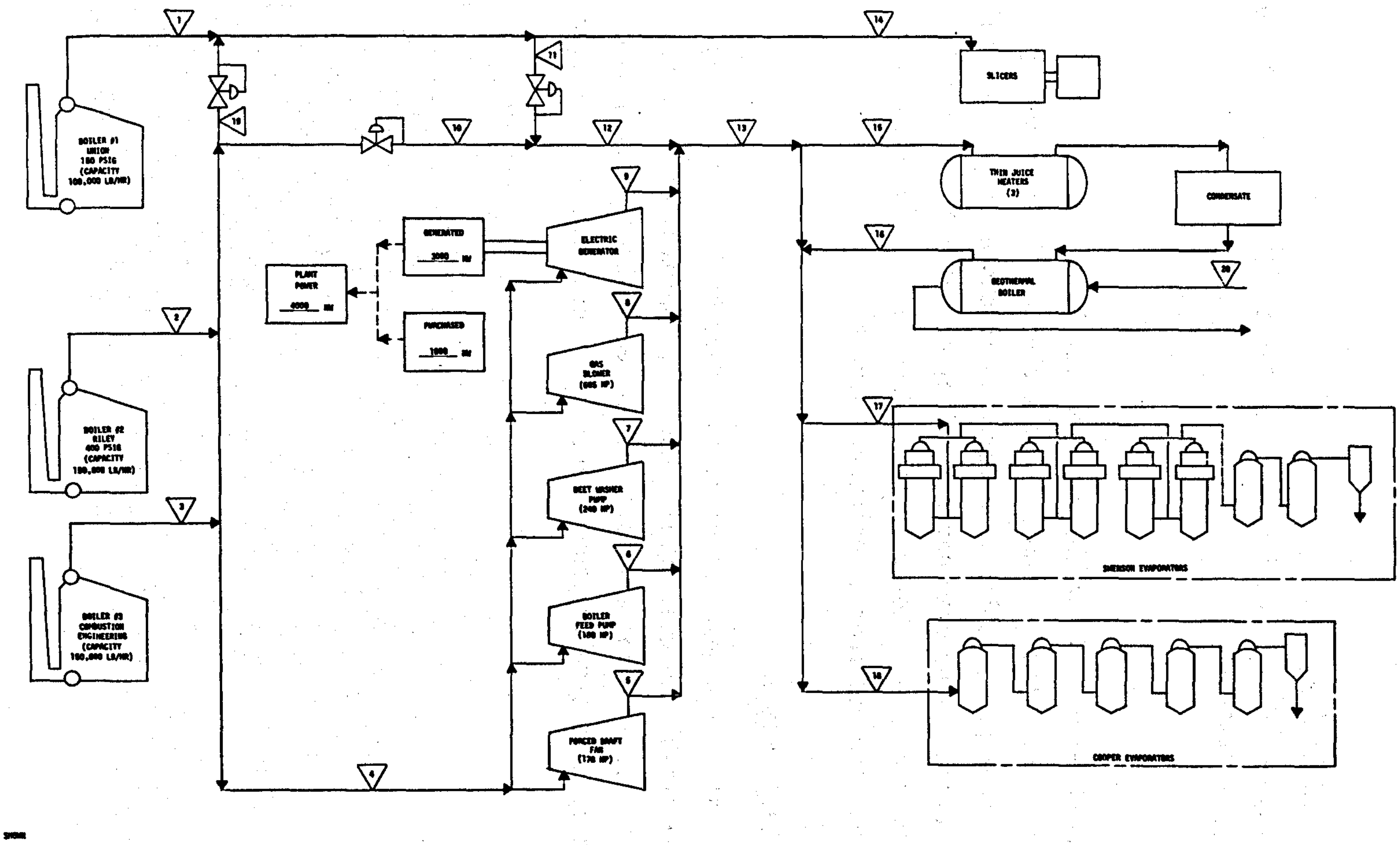
1.2 Process Steam Balance

The beet-sugar refining process as described requires relatively large quantities of low-pressure process steam. Therefore, the sugar industry usually finds it economical to generate its own electric power with a noncondensing steam turbine generator, which exhausts steam at the pressure required by the process. Further, the need for process steam has made it normal practice to power other large horsepower loads with mechanically driven noncondensing steam turbines to aid in balancing out the steam requirements in the whole plant.

The design boiler steam pressure is determined by establishing the exhaust steam pressure to be used in the evaporator first effect and the amount of power to be generated by the turbine prime movers. The boiler steam pressure is then selected, which will allow generation of the required power, using 65 to 85% of process steam requirements. The remaining 15 to 35% of the boiler steam is then "made up" by throttling live steam into the exhaust system to prevent blow off of unused steam during off design operations.

Oil, gas and coal are used as fuels for the boilers. The beet sugar factories in California are designed to use gas when available, and oil for standby because of restrictions on coal firing. The sugar factories in Utah and Idaho have converted to and plan to use coal for future campaigns.

The nominal boiler and exhaust steam balances for the Brawley factory 1976 campaign are indicated schematically in Figure 1-5. As indicated, the throttled steam make-up is approximately 34% of exhaust steam demand. It is noted that this throttled steam make-up could be provided by retrofitted boilers heated with geothermal energy without upsetting the balanced fixed turbine exhaust system, as discussed further in Section 3.



≈ 7% LOSSES NOT SHOWN

PROCESS STEAM

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
	GENERATED BOILER #1	GENERATED BOILER #2	GENERATED BOILER #3	H. P. TURBINE SUPPLY	FORCED DRAFT FAN	BOILER FEED PUMP	BEET WASHER PUMP	GAS BLOWER	ELECTRIC GENERATOR	MAKEUP FROM H.P. SUPPLY	MAKEUP FROM L.P. SUPPLY	TOTAL MAKEUP	EXHAUST PLUS MAKEUP	SLICER SUPPLY	THIN JUICE HTR SUPPLY	GENERATED GEOTHERMAL BOILER	SWENSON EVAPORATORS	COOPER EVAPORATORS	H.P. SUPPLY TO SLICERS	GEOTHERMAL FLUID
FLOW (LB/HR X 10^3)	57	73.3	100.2	141.3	9.9	7.9	15.6	23	84.9	32.2	46.5	77.7	219	11.5	24	—	133	62	—	—
TEMPERATURE (°F)	306	400	400	400	293	293		293	293	293	306	293	293	306	293	—	293	280	—	—
PRESSURE (PSIG)	100	400	400	400	45	45	45	45	45	45	100	45	45	100	45	—	45	25	—	—

GEOTHERMAL-SUGAR REFINING	TRW SYSTEMS GROUP
HOLLY SUGAR-BRAWLEY PROCESS STEAM (TYPICAL 1976 CAMPAIGN)	ENVIRONMENTAL, POWER AND FACILITIES DEPARTMENT SYSTEM INTEGRATION LABORATORY
DATE NOV 9, 1976	DWG. NO. 6021.36-01
DRAWN	
CHKD.	
APPRVD.	APPRVD. – PROGRAM OFFICE

FIGURE 1-5

Detailed tabulated breakouts of the nominal live, exhaust and vapor steam demands of the Brawley factory are indicated in Table 1-1. Promising points of application for geothermally generated steam are identified as those demands totalling 34% of throttled steam, which can utilize steam as low as 28 PSIG (272°F).

1.3 Thermal Energy Demands

The nominal thermal energy and fuel demands for the 1976 Brawley factory campaign are shown in Table 1-2.

1.4 Mechanical Power Demands

Steam turbine prime movers for large mechanical loads are used in the Brawley factory. As indicated in Figure 1-5 the electrical generator, gas compressor, beet washer pump, boiler feed pump and forced draft fan are all powered by steam turbines. By examination, all other motor loads were found to be less than 100 horsepower thereby raising doubt as to the feasibility of using vapor turbines powered from a geothermal source.

1.5 Non-Process Heat Demands

No demands exist in the baseline plant for space heating or cooling which might be convertible to geothermal. However, approximately 100 tons of refrigeration is required for crystallized and bulk sugar cooling which could be provided by geothermally powered absorption or steam jet refrigeration.

	STEAM BALANCE STEP	LIVE STEAM		EXHAUST	SWENSON			COOPER			TOTALS
		400 PSIG	150 PSIG	≤ 47 PSIG	FIRST VAPOR 30 PSIG 275°F	SECOND VAPOR 17 PSIG 255°F	THIRD VAPOR 12 PSIG 245°F	FIRST VAPOR 24 PSIG 266°F	SECOND VAPOR 14 PSIG 250°F	THIRD VAPOR 10 PSIG 241°F	
	PROCESS STEAM DEMANDS										
1	GRANULATOR			5,200							
2	CRYSTALLIZERS			100							
3	SWENSON THIN JUICE HEATER			3,400							
4	SWENSON EVAPORATORS			133,000							
5	SWENSON FIRST VAPOR MAKE-UP			10,400							
6	THIN JUICE BOILER				9,900						
7	LOW RAW MELTER				500						
8	SECOND CARB HEATER				7,700						
9	WHITE PANS				43,000						
10	CHAIN DIFFUSER					3,600					
11	THIN JUICE HEATER					3,400					
12	HIGH RAW PANS					10,000					
13	HIGH RAW MELTER					900					
14	BLENDER					3,000					
15	CHAIN RAW JUICE HEATERS						17,000				
16	COOPER THIN JUICE HEATER			4,900							
17	COOPER EVAPORATORS			62,000							
18	SLOPE DIFFUSER							5,000			
19	LOW RAW PANS								5,100		
20	CONCENTRATOR								4,800		
21	SLOPE RAW JUICE HEATERS									12,100	
22	THICK JUICE HEATER									1,100	
23	DIFFUSER SUPPLY TANK									1,000	
24	SLICERS		11,500								
25	TOTALS		11,500	219,000							230,500
	PROCESS STEAM SUPPLY										
26	MAKE-UP FROM 400 PSIG LIVE			31,800							
27	MAKE-UP FROM 150 PSIG LIVE			45,500							
28	GENERATOR TURBINE			85,000							
29	GAS BLOWER TURBINE			23,000							
30	BEET WASHER PUMP TURBINE			15,700							
31	BOILER FEED PUMP TURBINE			8,000							
32	FORCED DRAFT FAN TURBINE			10,000							
33	SLICER STEAM SUPPLY		11,500								
34	TOTALS		11,500	219,000							230,500
	LIVE STEAM SUPPLY										
35	UNION BOILER		57,000								
36	RILEY BOILER	73,300									
37	COMBUSTION ENGR BOILER	100,200									
38	TOTALS	173,500	57,000								230,500

HOLLY SUGAR BRAWLEY PLANT
NOMINAL 1976 PROCESS STEAM BALANCE (LB/HR)

$\boxed{\quad}$ PROMISING POINTS OF APPLICATION OF GEOTHERMAL STEAM ≥28 PSIG (271°F)

TABLE 1-1

TABLE 1-2 HOLLY SUGAR BRAWLEY PLANT
AVERAGE FUEL DEMAND
1976 CAMPAIGN

	BTUH	SLICING % OF PLANT DEMAND	EQUIVALENT FUEL DEMANDS GAS 10^6 CF/DAY	OIL BBL/DAY
400 PSI C.E. BOILER	138×10^6	24	3.1	563
400 PSI RILEY BOILER	91.7×10^6	16	2.1	374
150 PSI UNION BOILER	74.5×10^6	13	1.7	304
PULP DRYERS	269×10^6	47	6.1	1098
TOTAL PLANT	573×10^6	100	13.0	2339

NOTES:
1. BEETS SLICED 603, 364 TONS
2. FUEL - BOILER HOUSE 10M THERMS
   - PULP DRYERS 6M THERMS
3. OPERATIONS - APR 2 TO AUG 5 -- SLICING (126 DAYS)
   - AUG 5 TO SEP 22 -- JUICE (48 DAYS)
4. ENERGY ≅ 14% PRODUCT COST

2. GEOTHERMAL RESOURCE CHARACTERISTICS

A major part of beet sugar production in the United States comes from the eleven conterminous western states where hydrothermal resources are concentrated. Thirty-five of the fifty-five beet factories listed in Table 2-1 are in these eleven states.

Figures 2-1 and 2-2 provide an overall view of the geographic relations between beet sugar production and geothermal resources in the western United States. Figure 2-1 shows the locations of sugar beet growing areas and beet sugar factories, identified by their number in Table 2-1. In Figure 2-2, the beet growing areas are shown together with the hydrothermal resource occurrences identified by the U. S. Geological Survey in USGS Circular 726, a most authoritative current catalogue. These hydrothermal systems are characterized by different symbols on Figure 2-2, to show their estimated resource temperatures and their relative sizes and status of development. The heavy contour lines on Figure 2-2 enclose areas in which all hot springs listed by Waring (ref. 2-1) have surface temperatures greater then 120°F. These areas contain most of the known hydrothermal resources, and are the best prospective areas for new discoveries (ref. 2-2).

For converting existing factories to geothermal process heat, the existence of a viable resource within a few miles is an economic necessity. The conjunction of the Brawley field and the Holly factory is the most favorable known, since no other proven geothermal resource lies nearly so close to an existing factory. (Resources may be found even closer to the factory than the existing Union wells 8 miles away, since the factory lies in the promising offset region between the Imperial and Brawley faults. McCulloch Oil Co. is currently preparing to drill a geothermal test well on land adjacent to Holly property.)

For new or relocated plants, however, it may well be feasible to locate the plant close to geothermal resources that lie within economic shipping distance of beet growing areas. This distance is of the order of 100 miles, varying considerably with terrain and available roads and railways, since transit time and expense are both important factors. Figure 2-3 shows areas in which geothermal resources may lie within economic range of beet growing

Table 2-1

U. S. BEET SUGAR FACTORIES (Listed by State)

STATE	LOCATION (City/Town)	MAP LOCATION NO.	COMPANY
Arizona	Chandler	3	Spreckels
California	Betteravia	9	Union
	Brawley	6	Holly
	Clarksburg	12	American Crystal
	Hamilton City	4	Holly
	Manteca	10	Spreckels
	Mendota	8	Spreckels
	Santa Ana	5	Holly
	Spreckels	7	Spreckels
	Tracy	13	Holly
	Woodland	11	Spreckels
Colorado	* Brighton	20	Great Western
	* Delta	21	Holly
	Eaton	22	Great Western
	Ft. Morgan	19	Great Western
	Greeley	16	Great Western
	Johnstown	24	Great Western
	* Longmont	17	Great Western
	Loveland	15	Great Western
	Ovid	23	Great Western
	Rocky Ford	14	American Crystal
	Sterling	18	Great Western
Idaho	Idaho Falls	27	U and I
	Mini-Cassia	55	Amalgamated
	Nampa	26	Amalgamated
	Twin Falls	25	Amalgamated
Kansas	Kemp-Goodland	28	Great Western
Michigan	Bay City	41	Monitor
	Caro	37	Michigan
	Carrollton	38	Michigan

* Will not operate in 1977

Table 2-1 (Continued)

U. S. BEET SUGAR FACTORIES (Listed by State)

STATE	LOCATION (City/Town)	MAP LOCATION NO.	COMPANY
Michigan (cont'd)	Crosswell	39	Michigan
	Sebewaing	40	Michigan
Minnesota	Crookston	43	American Crystal
	East Grand Forks	44	American Crystal
	Moorhead	42	American Crystal
	Renville	54	American Crystal
Montana	Billings	29	Great Western
	Sidney	30	Holly
Nebraska	Bayard	49	Great Western
	Gering	48	Great Western
	Mitchell	50	Great Western
	Scottsbluff	47	Great Western
North Dakota	Drayton	46	American Crystal
	Hillsboro	45	American Crystal
Ohio	Findlay	53	Northern Ohio
	Fremont	52	Northern Ohio
	Ottawa	51	Northern Ohio
Oregon	Nyssa	31	Buckeye
Texas	Hereford	1	Holly
Utah	Garland	2	U and I
Washington	Moses Lake	32	U and I
	Toppenish	33	U and I
Wyoming	Lovell	34	Great Western
	Torrington	36	Holly
	Worland	35	Holly

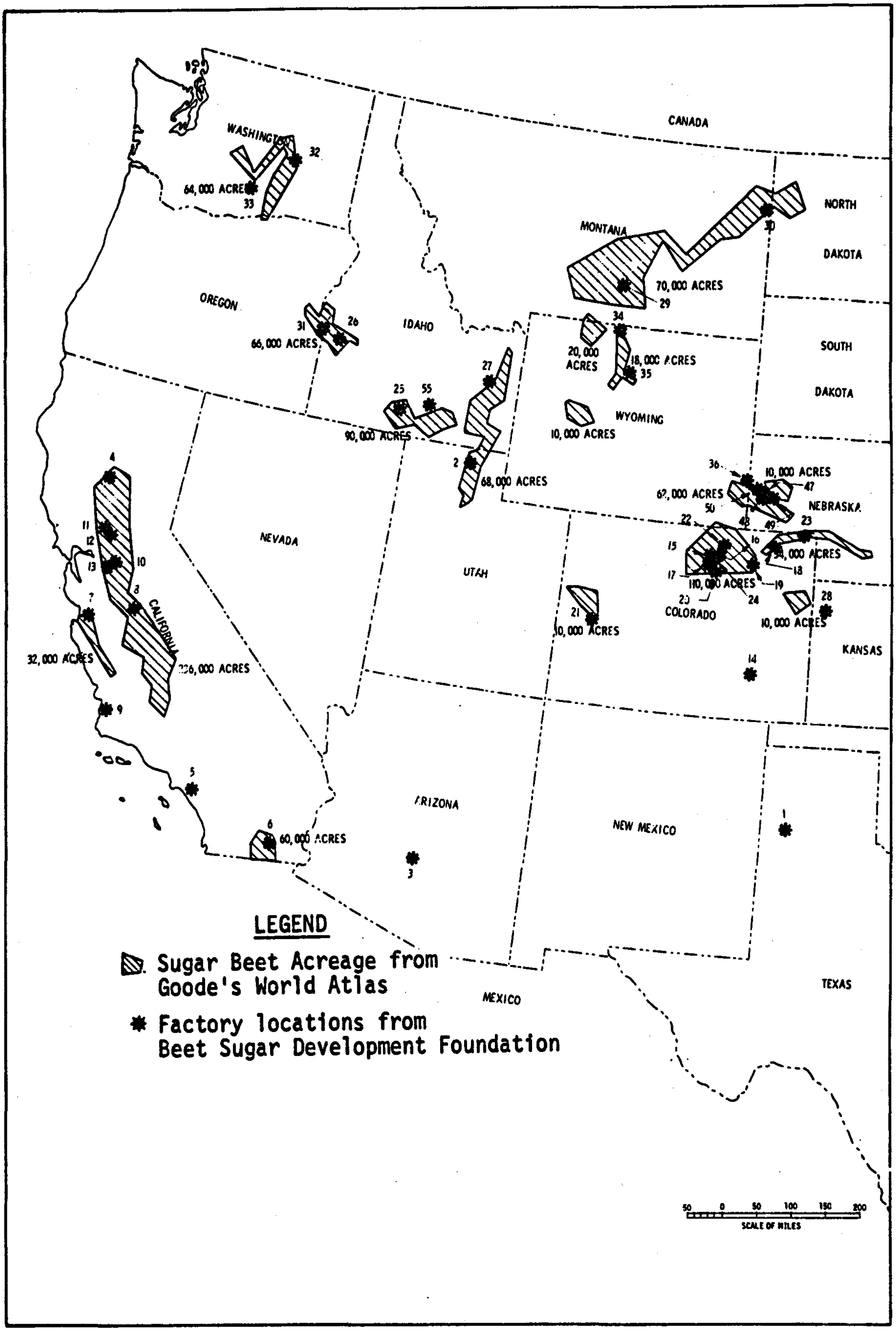


Figure 2-1 Sugar Beet Growing Area and Factories (see Table 2-1)

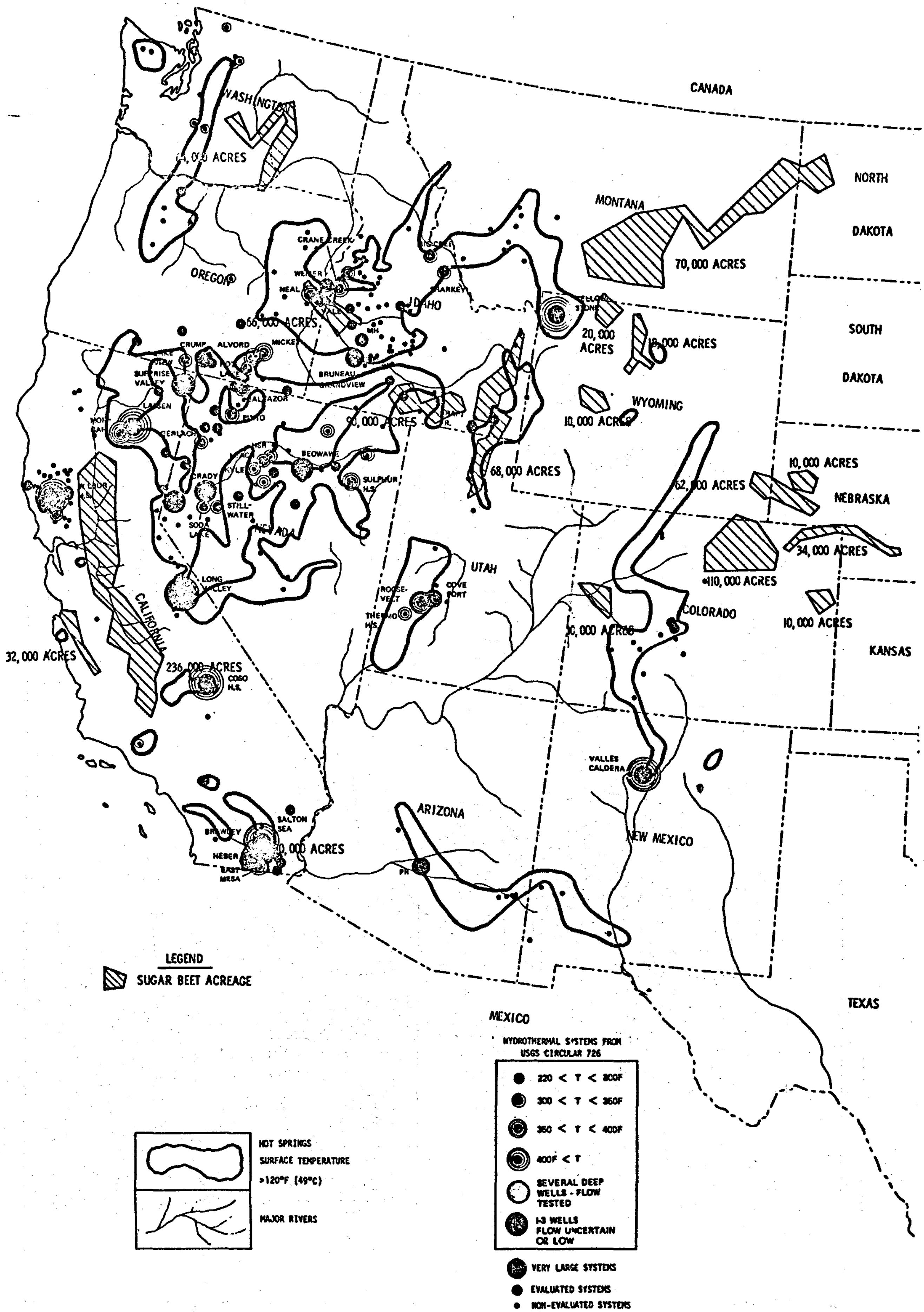


Figure 2-2 Sugar Beet Growing Areas and Hydrothermal Resources.

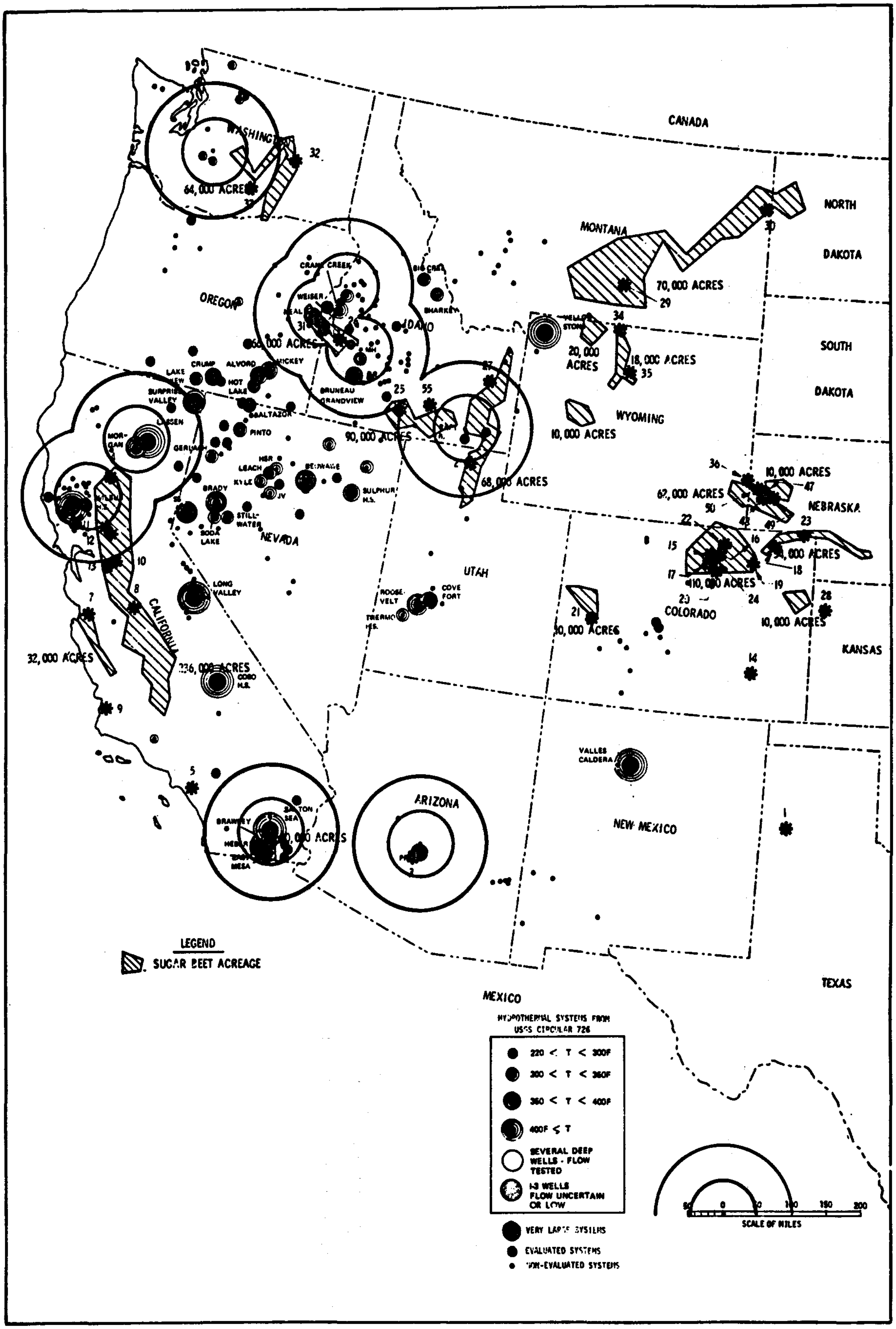


Figure 2-3 Selected Hydrothermal Resources Close to Beet Growing Areas.

areas, marked by circles of 50- and 100- miles radius around resource locations. In order of their estimated potential, these areas are: The Imperial Valley in California; southwest Idaho and adjacent parts of Oregon; southeast Idaho and adjacent parts of Utah; northern California; southern Arizona; and central Washington.

Table 2-2 summarizes some more detailed information on the geothermal resources of these areas. This information comes from various sources of which the USGS Circular 726 is the best source for reservoir extent and heat reserves, which have been estimated from most of the publicly available geological and geophysical data. Considering resource temperature and salinity, estimated reserves, state of resource development, and expected ease of transportation, the priority of Imperial Valley and southwest Idaho is clear from the data in Table 2-2. Geochemical evidence (ref. 2-3) suggests that southern Idaho may have widespread and abundant high-temperature resources at depth, that are concealed by mixing with cold water near the surface. If any large fraction of these suspected resources is proven by drilling, this region may well take first place in the use of geothermal process heat for sugar beets and other agricultural processing.

POTENTIAL GEOTHERMAL ENERGY SOURCES FOR SUGAR REFINING								
RESOURCE	TEMP (°F) GEOCHEMICAL TEMP	TEMP (°F) DEEP WELL TEMP	SALINITY (PPM) TDS	AREAL EXTENT (ACRES) USGS ESTIMATE	HEAT RESERVES (BILLION MILLION BTU)*	DEEP WELLS	OPERATOR OR MAJOR LEASEHOLDERS	BEET SUGAR FACTORIES IN AREA NUMBERED AS ON LOCATION MAP
IMPERIAL VALLEY, S. CALIFORNIA					*1/4 OF HEAT IN PLACE (USGS) ABOVE 250°F			
SALTON SEA	--	>600°F (4-8000')	250,000	13,000A	~15	>15 WELLS	PHILLIPS, SO. PAC. LAND CO., S.CAL EDISON	BRAWLEY (6): HOLLY
BRAWLEY	--	>400°F	20-50,000 (?)	4,500A	~2	5 WELLS	UNION, ST. OIL OF CAL.	
HEBER	--	390°F (4-5000')	10-15,000	12,000	~5	12 WELLS	CHEVRON, MAGMA, REPUBLIC, UNION (FAIR FLOWRATES)	
EAST MESA	--	390°F (8000')	2-10,000	7,000A	~3	10 WELLS	U.S. BUREAU OF RECLAMATION REPUBLIC GEOTHERMAL, MAGMA (FAIR FLOWRATES)	
SW IDAHO								NYSSA (31): AMALGAMATED NAMPA (26): AMALGAMATED
CRANE CREEK	360°F	POSSIBLY	--	7,500A	~2	NO WELLS	--	
WEISER	320°F	MUCH HIGHER	--	8,500A	~2	NO DEEP WELLS	--	
VALE H.S. (ORE.)	320°F	--	--	12,000	~2	NO WELLS	--	
MOUNTAIN HOME	--	350°F (9500')	<800	?	?	GULF-BOSTIC	GULF ENERGY & MINERALS (NO FLOW)	
BRUNEAU-GRANDVIEW	290°F POSSIBLY MUCH HIGHER		--	500,000A	UNCERTAIN MAY BE LARGE	NO DEEP WELLS	--	
SE IDAHO								
RAFT RIVER	360°F	297°F (4-6000')	<2000	5,000A	~1	RRGE #1 RRGE #2	ERDA + CONSORTIUM (GOOD FLOW FROM WELLS)	GARLAND (2): U&I MINI-CASIA (55): AMALG. TWIN FALLS (25): AMALG.
BRIGHAM CITY (UTAH)	>400°F	285°F (10,000')	55,000	?	?	USV-DAVIS #1	GEOTHERMAL KINETICS (GKI) (NO FLOW)	IDAHO FALLS(27): U&I
N. CALIFORNIA								HAMILTON CITY (4): HOLLY
GEYSERS	--	460°F	STEAM	17,000A	~15	OVER 200 WELLS	UNION • BURMAH, SHELL	WOODLAND (11): SPRECKELS
CALISTOGA	320°F	278°F (>2000')	?	1,000A	<1	1 WELL >2000'	CALISTOGA POWER CO.	CLARKSBURG (12): AM. CRYSTAL
WILBUR H.S.	360°F	285°F (3600')	30,000	4,000A	~1	1 WELL 3600'	CORDERO MINING CO. (GOOD FLOW)	MANTECA (10): SPRECKELS
MORGAN SPGS.	410°F		?	1,000A	~1	NO WELLS	--	TRACY (13): HOLLY
ARIZONA		305°F (9000')	60,000			PR #1		
CHANDLER	--	352°F (10,500)		600A	<<1	PR #2	GEOTHERMAL KINETICS (GKI) (GOOD FLOW MAY BE OBTAINABLE)	CHANDLER (3): SPRECKELS
WASHINGTON								
LONGMIRE H.S.	340°F	--	?	?	?	NO WELLS	--	TOPPENISH (33)
SUMMIT CK.	340°F	--	?	?	?	NO WELLS	--	MOSES LAKE (32)

Table 2-2. Potential Geothermal Energy Sources for Sugar Refining.

REFERENCES

2-1 Waring, G. A., 1965, Thermal Springs of the United States and Other Countries of the World, USGS Prof. Paper 492.

2-2 TRW Systems and Energy Group, for Electric Power Research Institute (EPRI), Final Report to press, December, 1975, Utilization of U.S. Geothermal Resources (Technical Planning Study 76-638).

2-3 White, D. E. and Williams, D. L., Assessment of Geothermal Resources of the United States - 1975, Geological Survey Circular 726.

3. CONCEPTUAL DESIGNS AND PERFORMANCE ANALYSES

The purpose of Task 3 was to select the most promising points of application for geothermal energy, in the baseline factory described in Section 1 and evaluate the technical feasibility for factory retrofit utilizing the local hydrothermal resources of 300°F or less. Conceptual designs were synthesized and analyzed of alternate energy supply systems providing geothermal fluids to the factory and of alternate systems for retrofit or new factory extraction of heat from the geothermal fluid and transferring it to the major process loads.

The results of these design syntheses and analyses are described below.

3.1 Potential Baseline Applications

There are many portions of the sugar refining process that operate at temperatures of less than 300°F; however, most of these low temperature heating requirements are satisfied by evaporator vapors which are in effect process heat tailings, as described in Section 1. Therefore, low grade (≤ 300°F) geothermal energy cannot be directly substituted for these vapor heating supplies without upsetting the balanced boiler live steam turbine exhaust steam and evaporator vapor heat transmission system in a conventional beet-sugar factory. However, 15 to 35% of exhaust is made-up by throttling live boiler steam as described in Section 1. In the Holly Brawley factory nominally 34% of the exhaust steam demands are throttled live steam. Table 1-1 indicates these demands, totaling 34%, which could utilize medium pressure, 25 to 28 PSIG (268 to 272°F) steam as potential for application of geothermally generated steam from resource temperatures of ≤300°F. The process steam demands for the Cooper evaporators, Cooper thin juice heater, thin juice boiler and low raw melter are approximately 77,000 pounds of 28 PSIG steam per hour. This approach is technically feasible with 300°F geothermal fluids, and also economically competitive with fossil fuels as indicated in Section 6, Figure 6-3.

The beet pulp drying operation appears to offer the greatest opportunity for fossil fuel savings in that approximately 47% of the total Brawley factory fuel demand is required as indicated in Table 1-2. Various means of utilizing geothermal heat in the pulp drying process were identified and examined as described in subsequent Section 3.2.2. These investigations indicate that length of conventional dryers or the dwell time must be increased by a factor of 4 to 6 when utilizing geothermal energy.

3.2 Process Application Concepts

Geothermally heated process application concepts which were investigated for sugar refining, pulp drying, mechanical power generation and refrigeration are described below.

3.2.1 Refining Process

The retrofit potential for providing process steam in the Holly Brawley baseline factory has been discussed in Section 3.1. The potential for providing geothermal process heat in other factories is assessed in Table 3-1. Sugar beet factory characteristics are tabulated for factories adjacent to the potentially attractive geothermal resource areas identified in Section 2. As shown, most of these factories require process steam exhaust temperatures similar to the baseline factory. On a retrofit basis, we might expect to replace 15 to 35% of exhaust make-up steam similar to the baseline case. However, it is noted that other geothermal resources and temperatures are not as well defined as for the Brawley area which results in lower potential ranking as indicated in Table 3-1.

New factories can be designed with multiple-effect evaporators to operate with 25 PSIG steam ($\sim 268^{o}F$).

GEOTHERMAL POTENTIAL - SUGAR BEET FACTORY CHARACTERISTICS

REFERENCE DESIGNATION		LOCATION	FIRM	STANDARD DAILY SLICE (TONS/DAY)	GENERATOR (KW)	PRIME MOVER STEAM PRESSURES (PSIG)		EXHAUST TEMPERATURE		GEOTHERMAL INDICATOR (WITHIN 100 MILES)		TYPE	GEOTHERMAL FIELD	AREA	PRIMARY FUEL	GEOTHERMAL POTENTIAL
TRW	HDBK*					INLET	OUTLET (EXHAUST)	°C	°F	CHEMICAL TEMP °F	MEASURED TEMP °F					
33	I4	TOPPENISH	U&I	3925	1500	250	40	142	287	340	--	HOT SPRINGS ONLY	LONGMIRE	WASH	COAL	12
26	A4	NAMPA	AMALGAMATED	9000	500 2300 6000	215 215 400	35	138	281	360 320	-- -- -- -- -- --	2 WELLS - LO FLOW DEEP (9,000 FT)	CRANE CK. WEISER	SW IDAHO	COAL	6
31	A5	NYSSA	AMALGAMATED	6650	550 1500 3000	230 400 230	37	139	283	320 -- -- --	-- -- -- 350		VALE H.S. MOUNTAIN HOME		COAL	3
25	A3	TWIN FALLS	AMALGAMATED	4800	1500 2500	275	30	134	274	360	297	3 RAFT RIVER WELLS	RAFT RIVER	SE IDAHO	COAL	7
55	A2	MINI-CASIA	AMALGAMATED	7000	2500 300	200 400	35	138	281						COAL	4
2	I1	GARLAND	U&I	2700	1500	300	30	134	274	>400	285	1 BRIGHAM CITY - NO FLOW.	BRIGHAM CITY		COAL	8
27	I2	IDAHO FALLS	U&I	4400	600	160	40	142	287						COAL	5
4	H1	HAMILTON CITY	HOLLY	2400		200	35	138	281		460	GEYSERS OVER 200 WELLS	GEYSERS	N CAL	OIL	9
11	S3	WOODLAND	SPRECKELS	3450	1000 2000	300	45	144	292	320 360	278 285		CALISTOGA WILBUR H.S.		OIL	10
12	X1	CLARKSBURG	AMER. CRYSTAL	3000	2500	200	20	126	259	410	-- -- --		MORGAN SPGS.		OIL	11
6	H9	BRAWLEY	HOLLY	6500	3000	400	47	146	294	-- -- -- -- -- -- -- -- -- -- -- --	600 400 390 390	SALTON SEA - 15 WELLS BRAWLEY - 5 WELLS HEBER - 12 WELLS MESA - 11 WELLS	SALTON SEA BRAWLEY HEBER EAST MESA	S CAL	OIL	1
3	S5	CHANDLER	SPRECKELS	4250	5000	595	45	-- -- --	292	-- -- --	305-352	2 WELLS - LO FLOW DEEP (9,000 FT)	CHANDLER	ARIZ	OIL	2

* "BEET SUGAR TECHNOLOGY" (REF 3-1) ** BASIS 15°F APPROACH - 25 PSIG 1st EFFECT EVAPORATOR

Table 3-1

Two methods of extracting geothermal heat for the process were postulated and analyzed as indicated in Figure 3-1. Alternate HE-1A considered boiling potable water in a geothermally heated boiler to produce process steam. The second approach, Alternate HE-2A, is to utilize separated steam from the well thus beneficially negating the boiler heat exchanger approach losses of Alternate HE-1A. However, it is noted that the noncondensibles must be removed and H_2S neutralized. The approach of Alternate HE-1A is selected as optimum for retrofit applications with remote wellheads requiring reinjection because of the ease in pumping and handling of the single phase liquid.

Alternate heat extraction approaches with the process adjacent to, or remote from the wellheads are identified schematically in Figure 3-2. The Alternate HE-1A-1A is selected as optimum for the same reasons as discussed with respect to Alternate HE-1A above.

A representative schematic of providing geothermally generated make-up process steam to the Brawley baseline factory is shown as Option A in Figure 3-3.

3.2.2 Pulp Drying

Beet pulp drying appears to offer the greatest opportunity for fuel savings in sugar beet factory operations. Pulp drying accounts for 30 to 50% fuel demand and it is separate from integrated process steam requirements. The Brawley factory beet pulp nominal drying requirements when processing 6,000 tons of beets per day are as follows:

	Wet Pulp		Dry Pulp	
Solids	20%	19.9 tons/hr	90%	17.9 tons/hr
Water	80%	79.5 tons/hr	9%	1.8 tons/hr
Totals	100%	99.4 tons/hr	100%	29.7 tons/hr

Several conceptual approaches were postulated and investigated as follows:

a. Air Dryer Retrofit - One approach is to replace the gas/oil burners with geothermally heated air drying coils and increase the dryer tube lengths (to increase dwell time) as shown as in Figure 3-4.

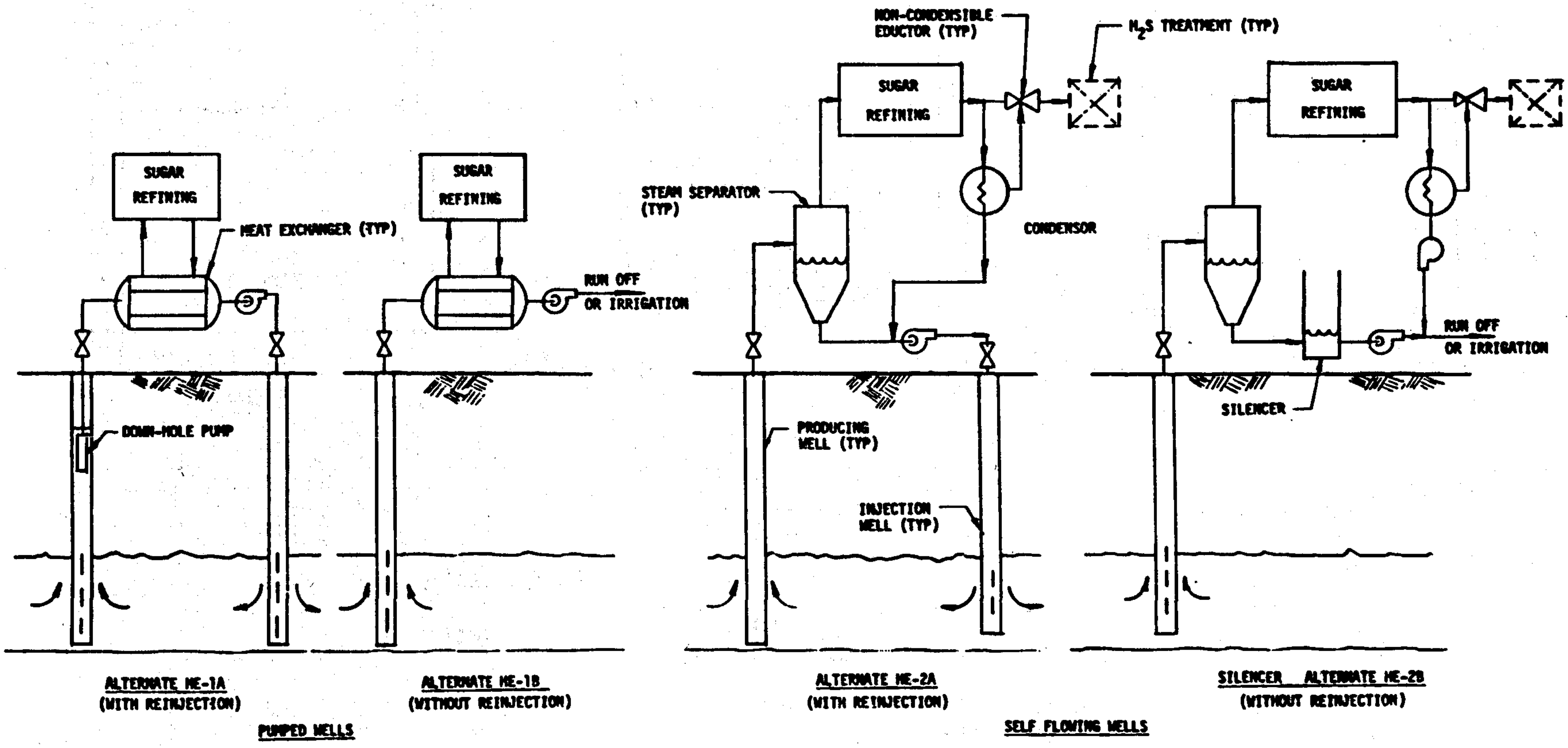


Figure 3-1 Well Flow/Effluent Handling Alternatives

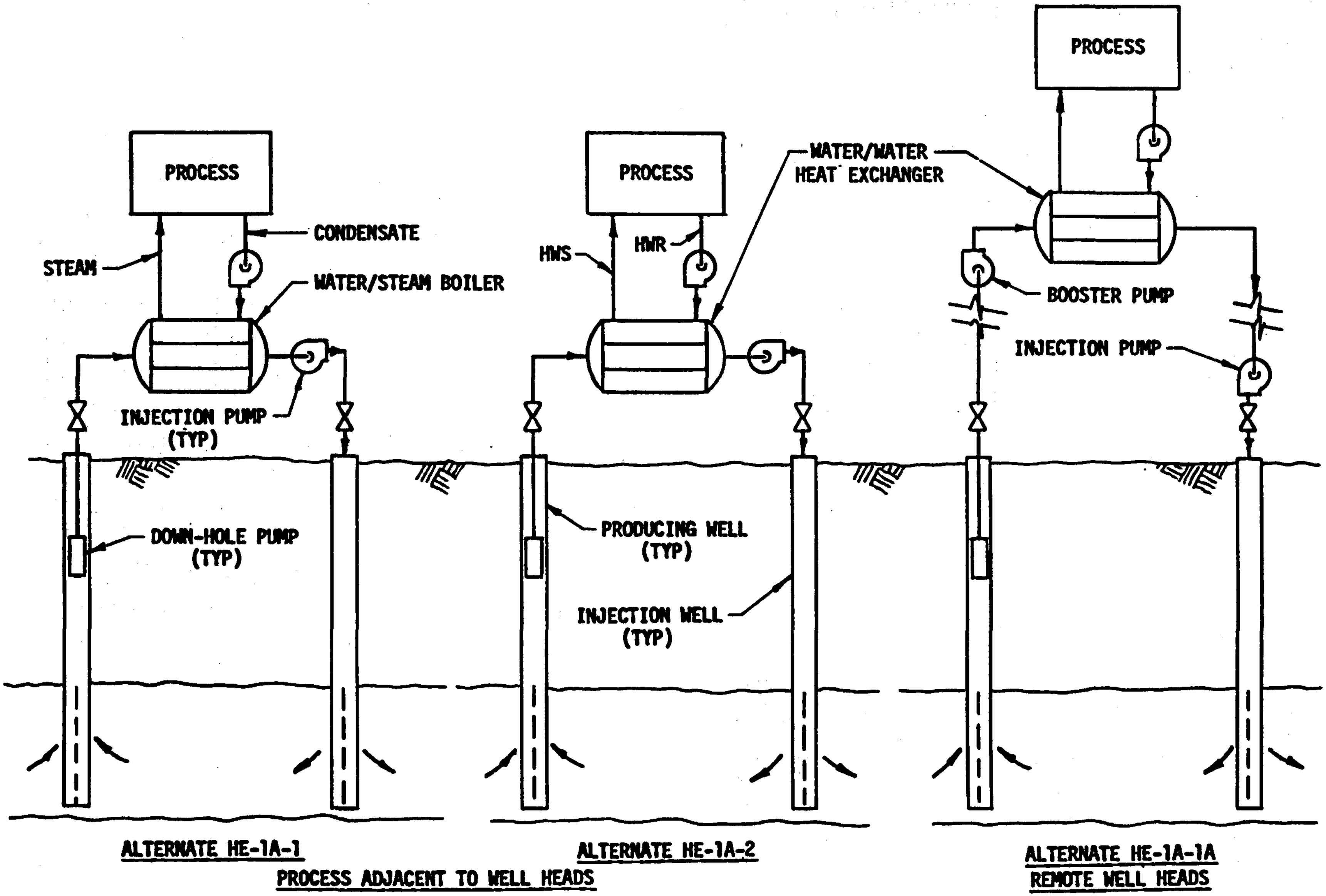


Figure 3-2 Heat Extraction Alternatives - Pumped Well With Reinjection

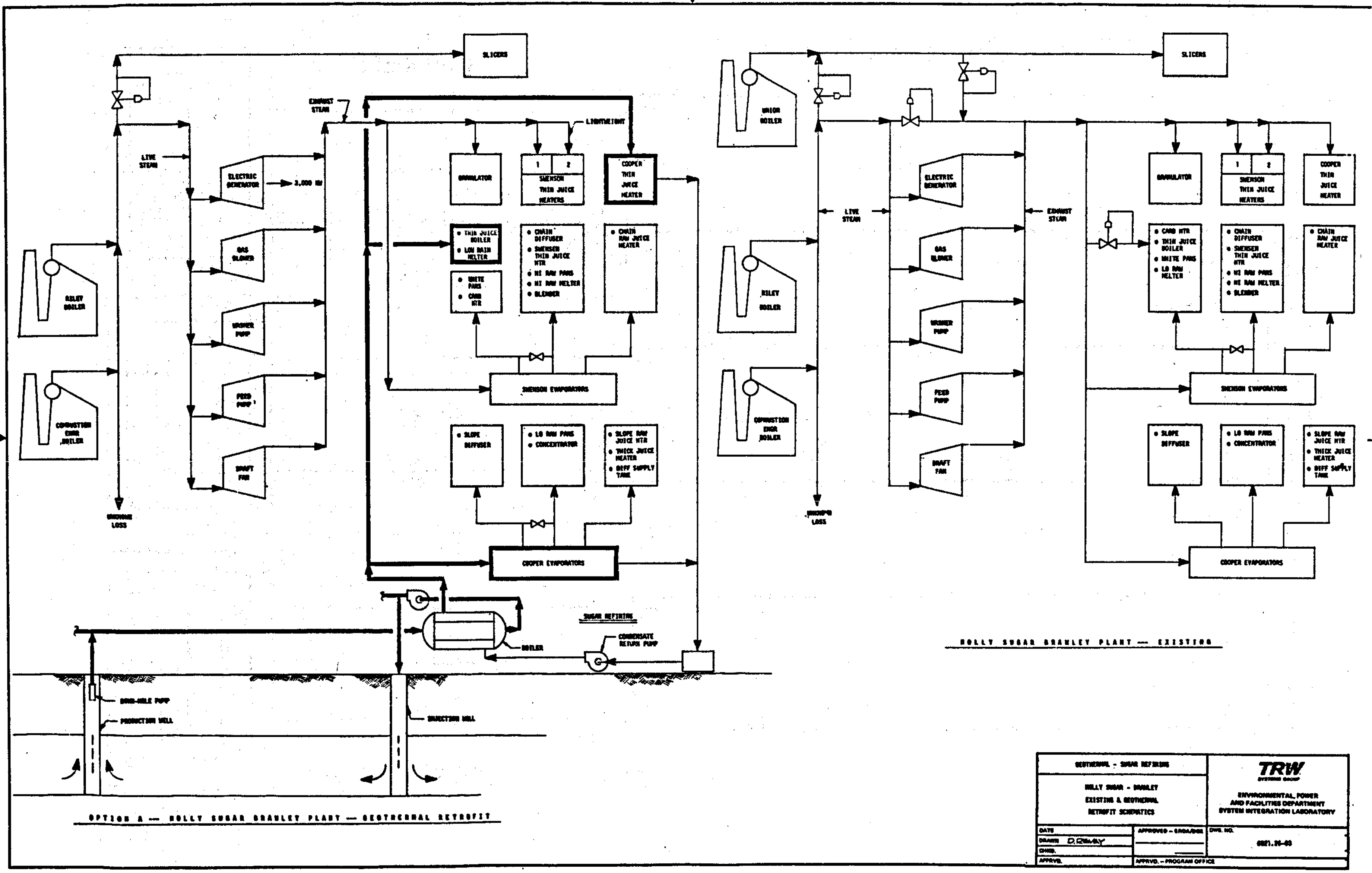

SLICERS
EXHAUST STEAM
LIGHTWEIGHT
LIVE STEAM
ELECTRIC GENERATOR
3,000 KW
GAS BLOWER
WASHER PUMP
FEED PUMP
DRAFT FAN
RILEY BOILER
COMBUSTION ENGR BOILER
UNKNOWN LOSS
GRANULATOR
SWENSON THIN JUICE HEATERS
COOPER THIN JUICE HEATER
THIN JUICE BOILER
LOW RAW MELTER
WHITE PANS
CARB HTR
CHAIN DIFFUSER
SWENSEN THIN JUICE HTR
HI RAW PANS
HI RAW MELTER
BLENDER
CHAIN RAW JUICE HEATER
SWENSON EVAPORATORS
SLOPE DIFFUSER
LO RAW PANS
CONCENTRATOR
SLOPE RAW JUICE HTR
THICK JUICE HEATER
DIFF SUPPLY TANK
COOPER EVAPORATORS
SUGAR REFINING
CONDENSATE RETURN PUMP
BOILER
DOWN-HOLE PUMP
PRODUCTION WELL
INJECTION WELL
OPTION A — HOLLY SUGAR BRAWLEY PLANT — GEOTHERMAL RETROFIT
UNION BOILER
HOLLY SUGAR BRAWLEY PLANT — EXISTING
GEOTHERMAL - SUGAR REFINING
HOLLY SUGAR - BRAWLEY EXISTING & GEOTHERMAL RETROFIT SCHEMATICS
TRW SYSTEMS GROUP
ENVIRONMENTAL, POWER AND FACILITIES DEPARTMENT SYSTEM INTEGRATION LABORATORY
DATE
DRAWN D. Graby
CHKD.
APPRVD.
APPRVD. - PROGRAM OFFICE
DWG. NO.

Figure 3-3

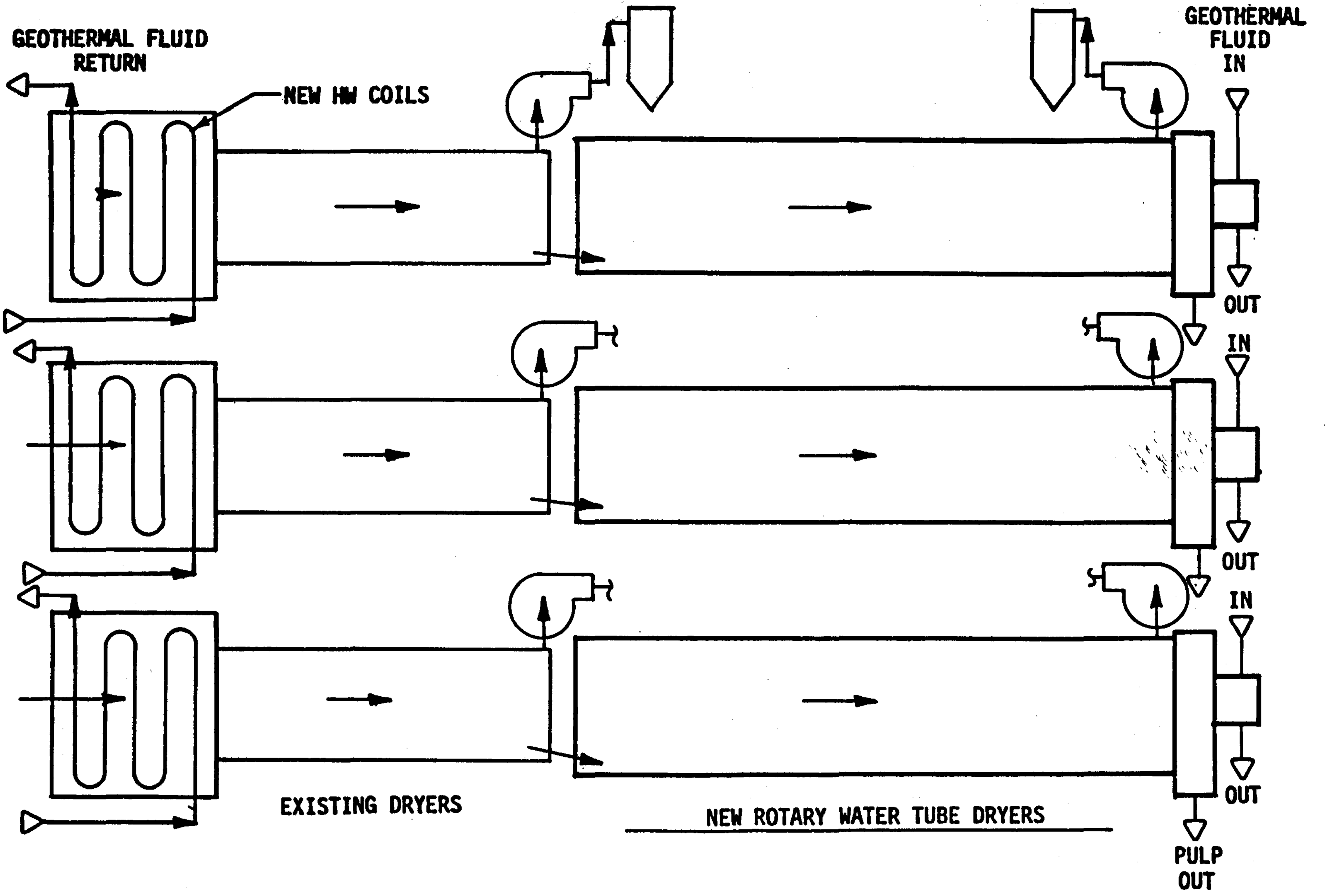


Figure 3-4 Pulp Dryer -- Option A (Holly Retrofit)

b. Rotary Water Tube Dryer - Rotary water tube (or steam tube) dryers, which are conventional to the chemical industry, as shown in Figure 3-5.

c. Rotary Air Dryer - Rotary air dryers, which are conventional for food, feed, fiber and fertilizer drying applications as shown in Figure 3-6.

d. Hybrids - Hybrid drying approaches investigated were the conveyor and autoclave drying approaches shown in Figure 3-7.

3.2.3 Mechanical Power Generation

As mentioned previously in Section 1, high pressure steam turbine prime movers are used in most sugar factories for loads over 200 HP. The medium steam pressures that would be available from 300°F geothermal sources would not be economic for this serivce. However, in any approach using a binary system for power generation such as discussed in Section 3.4.2, a Rankine power cycle could be considered for larger energy consumptive loads.

3.2.4 Refrigeration

Approximately 100 tons of refrigeration is required for crystallized and bulk sugar cooling in the Brawley factory. Geothermally fired absorption cooling could easily be adopted. The absorption cooling is especially beneficial in that it could utilize cascaded geothermal effluents from the process or pulp drying application; e.g., Carrier Unit 16JB014 would produce 100 tons of refirgeration using 311 GPM of 240°F geothermal effluent. This flow is equivalent to one-third the flow of a typical 1,000 GPM well.

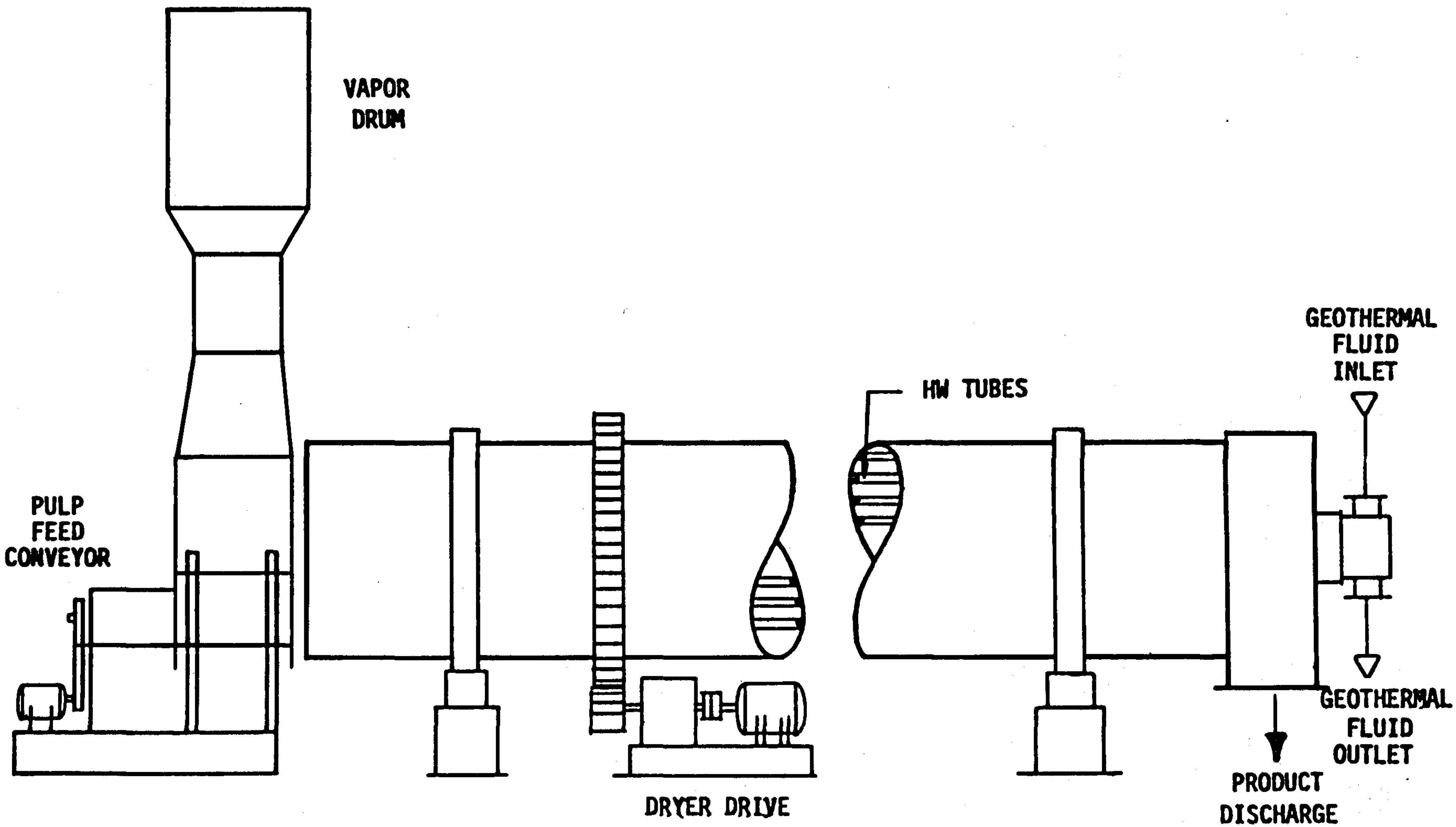


Figure 3-5 Pulp Dryer -- Option B (Rotary Water Tube Dryer)

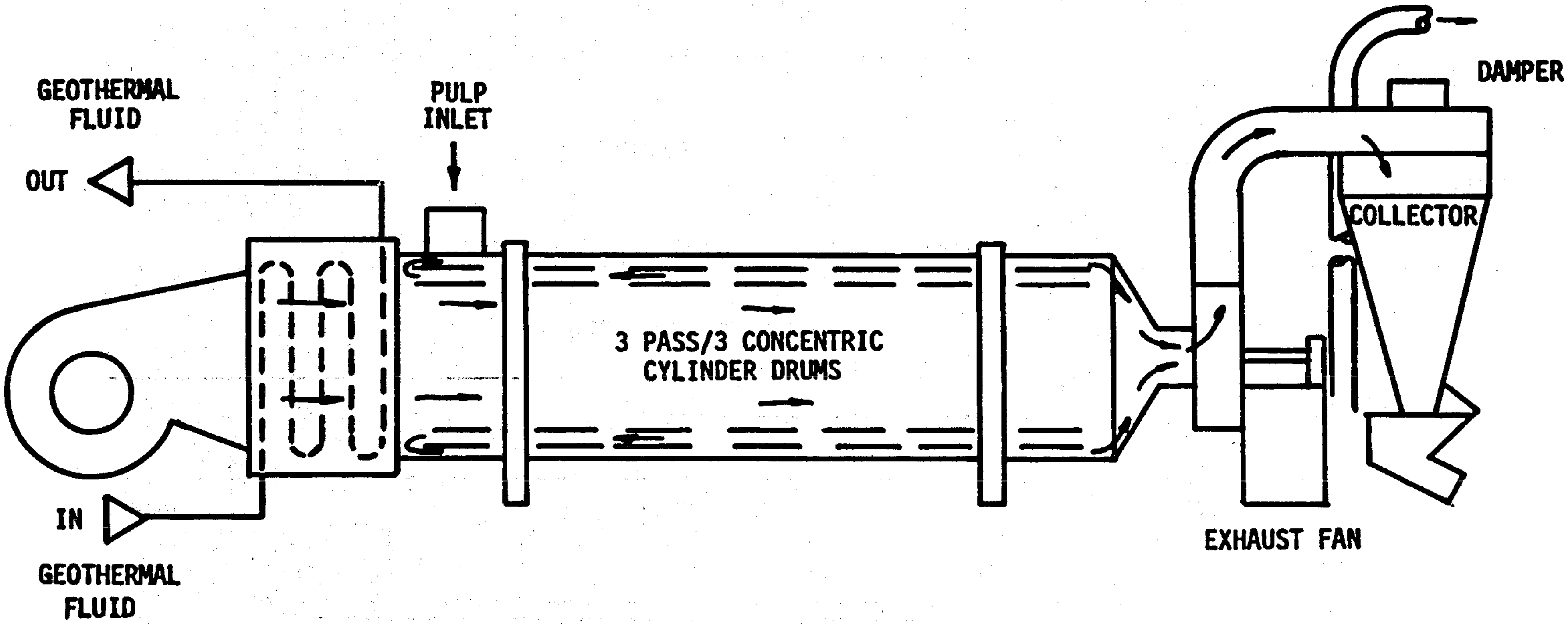


Figure 3-6 Pulp Dryer -- Option C (Rotary Air Dryer)

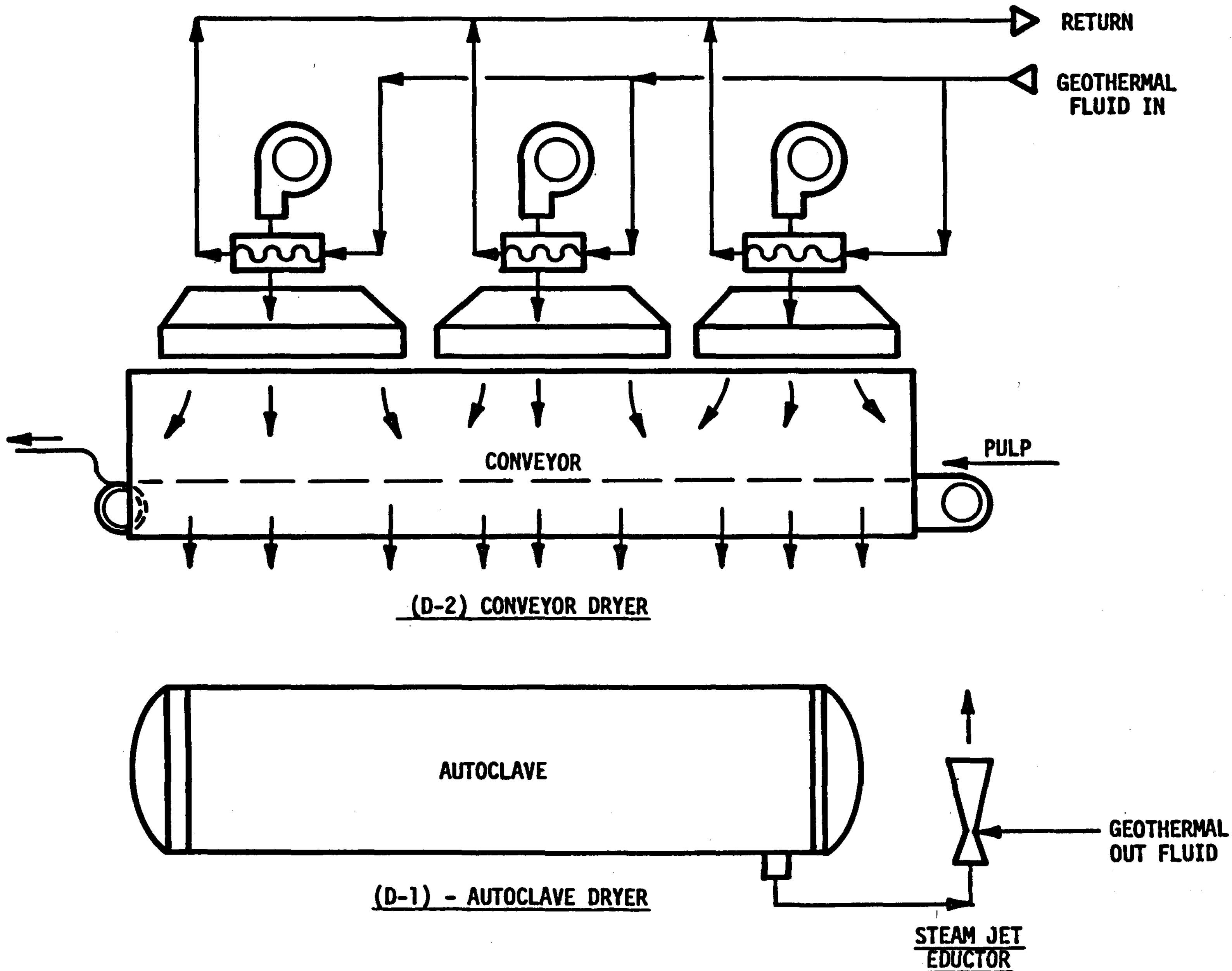


Figure 3-7 Pulp Dryers -- Option D (Hybrids)

3.3 Energy Supply System Concepts

The energy supply system is defined as the system including the production and injection wells, down-hole pump (if required) casing head equipment, interconnecting pipeline and process heat exchanger.

Alternate configurations considering directional drilling versus vertical drilling are shown in Figure 3-8. It has been determined, in costing studies developed by TRW for ERDA, that directionally drilled wells with horizontal throws up to 5,000 feet are competitive with vertical wells and buried interconnecting pipelines for sedimentary basin drilling as in the Imperial Valley, California

A typical field layout of the wells that might be required for process steam make-up and pulp drying in a retrofitted plant is shown in Figure 3-9.

3.4 Configuration Analyses

3.4.1 Process Control and Off-Design Operation

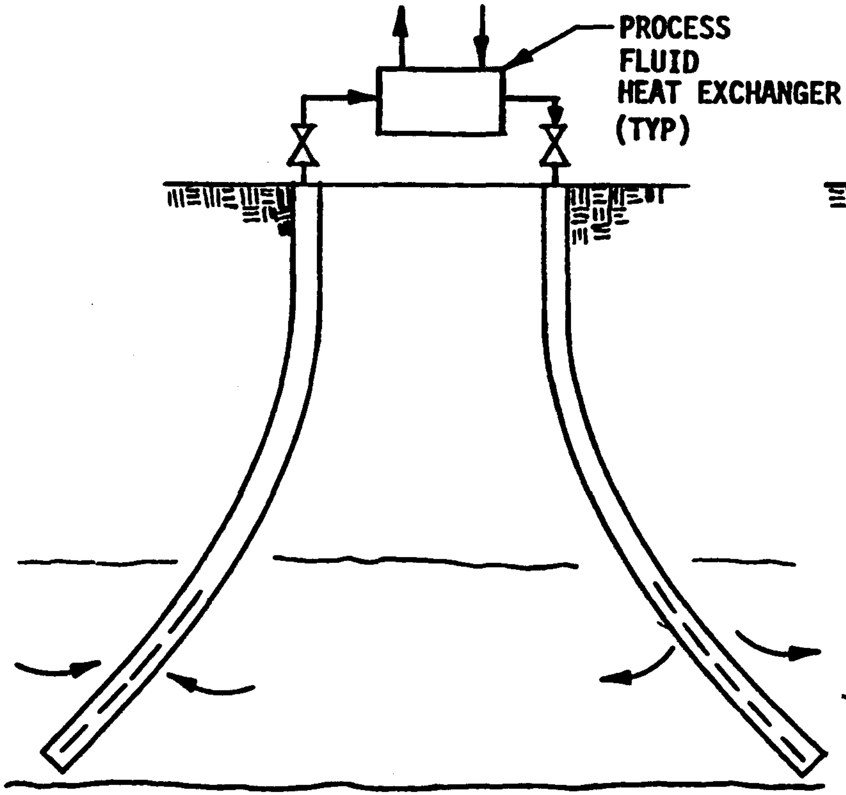
In concepts using 300°F geothermal heat for process steam and pulp drying relatively close temperature approaches are required to maximize the utilization. Wide plus variations in temperature could be easily accommodated; however, minus variations would probably be limited to <5°F. Use of geothermal fluids up to 350°F would permit expanding this lower temperature limiting variation to 10 to 20°F.

3.4.2 Combined Fossil Fuel/Geothermal Configurations

New sugar factory options should consider a combined fossil fuel/geothermal energy system (Option C) or a total geothermal energy system (Option B) as identified and shown in Figure 3-10.

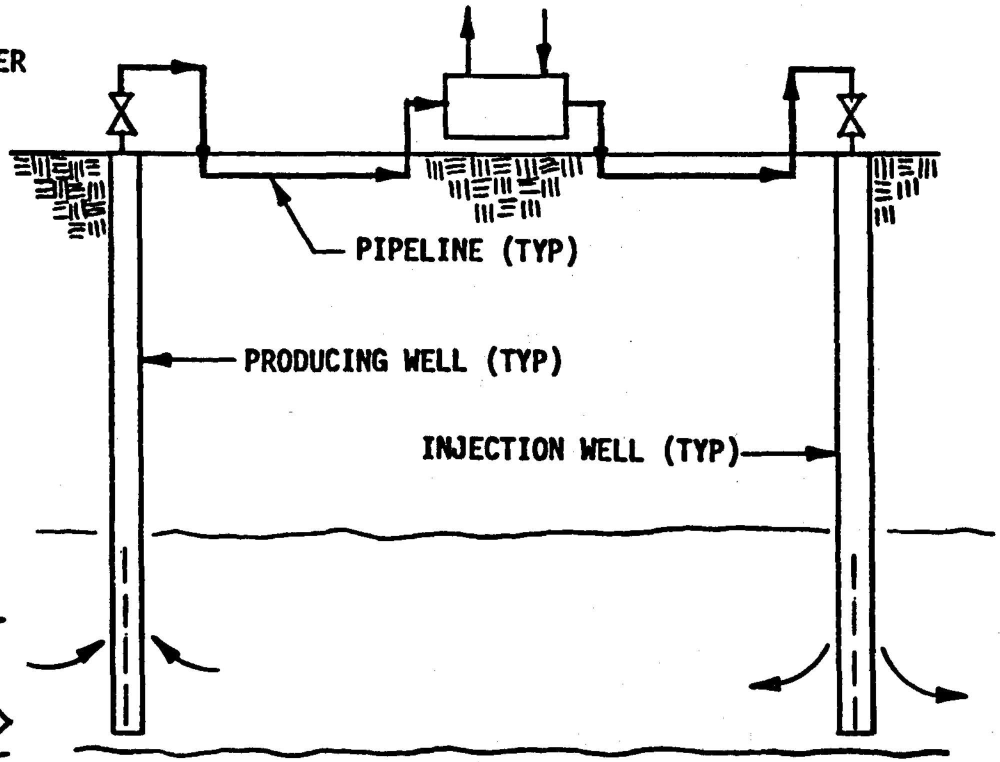
3.4.3 Geothermal Resource Variations

Three representative situations were considered based on variations in geothermal source fluid characteristics:



ALTERNATE A

DIRECTIONAL DRILLED



ALTERNATE B

VERTICAL DRILLED

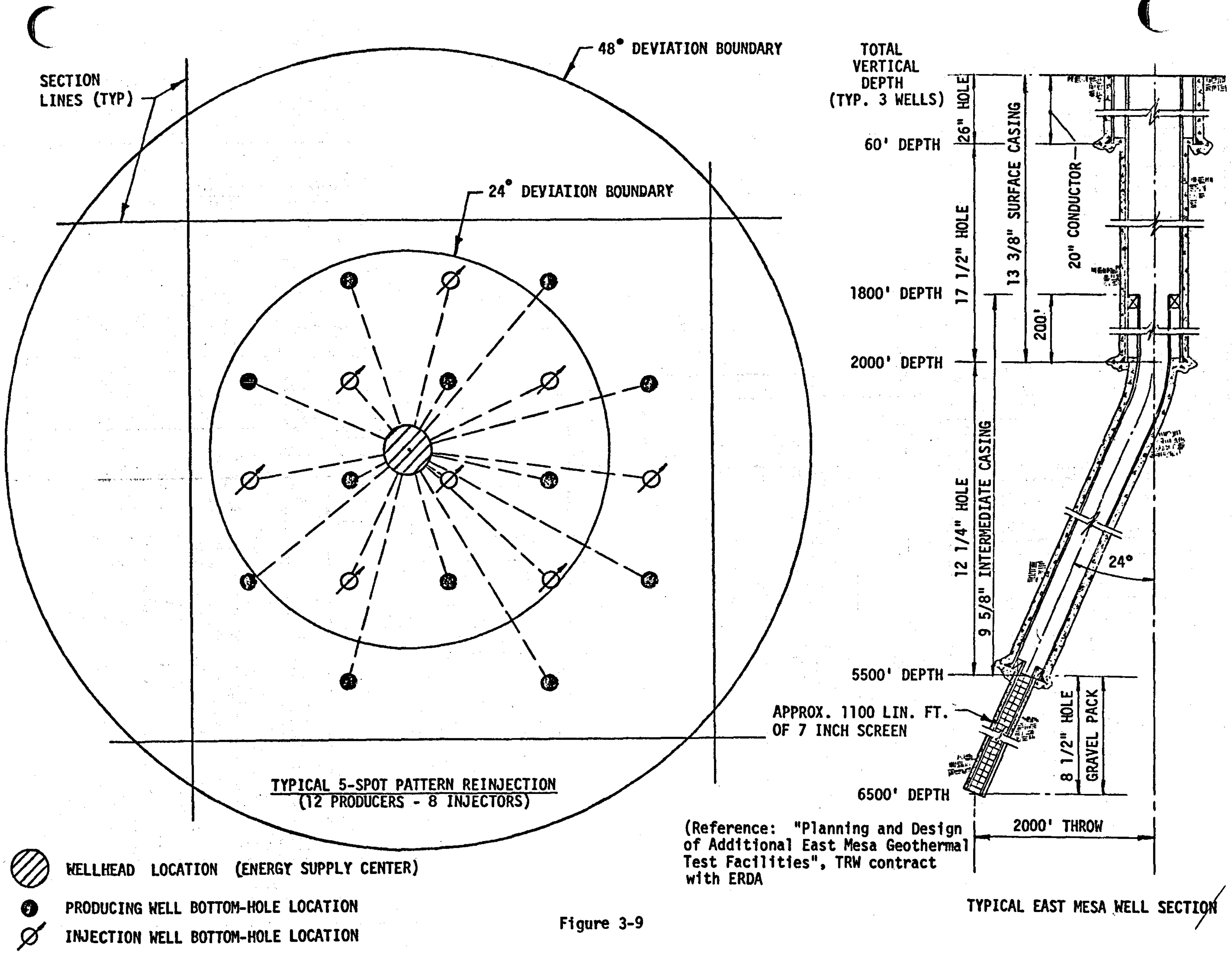
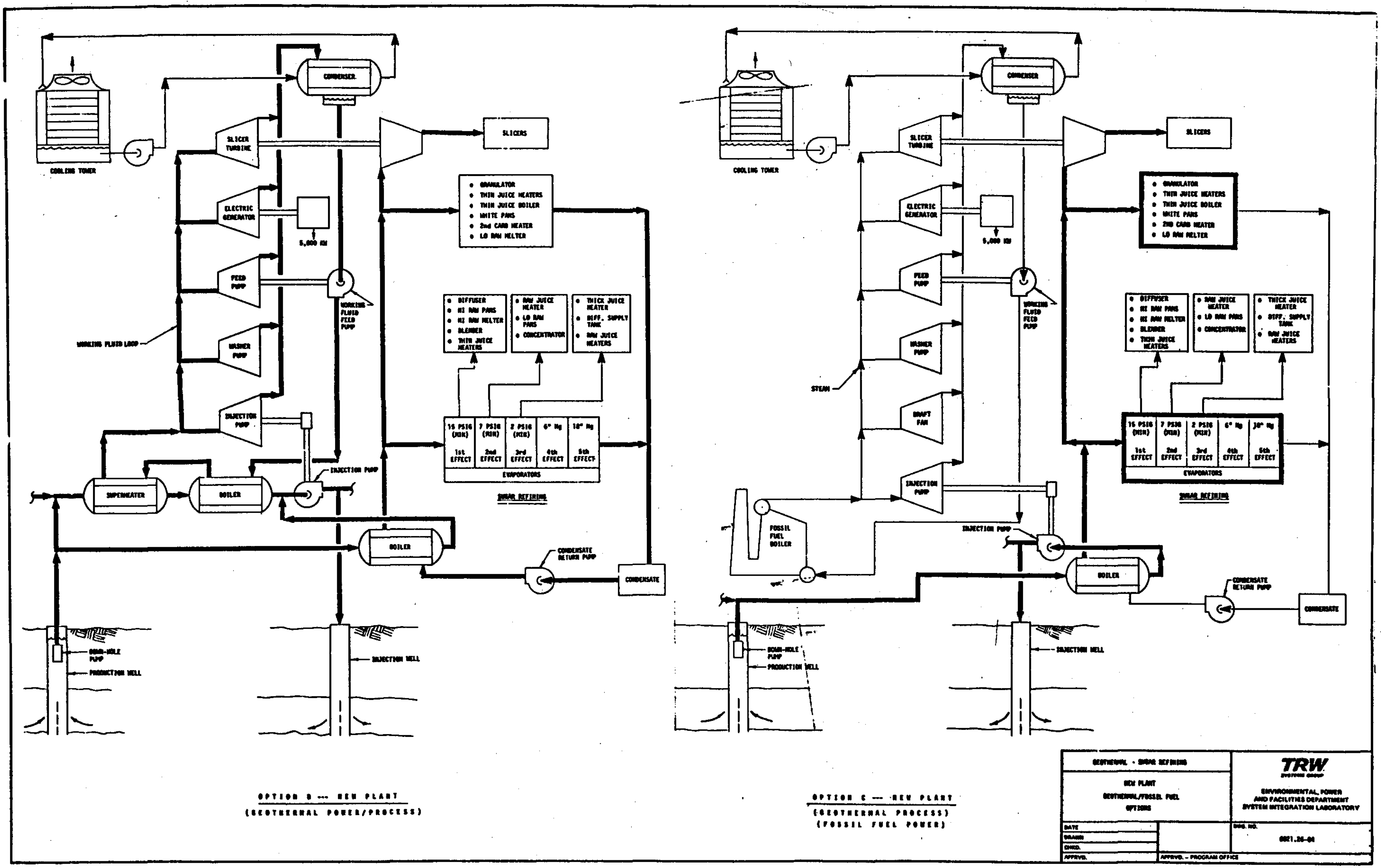

48° DEVIATION BOUNDARY
SECTION LINES (TYP)
24° DEVIATION BOUNDARY
TYPICAL 5-SPOT PATTERN REINJECTION
(12 PRODUCERS - 8 INJECTORS)
WELLHEAD LOCATION (ENERGY SUPPLY CENTER)
PRODUCING WELL BOTTOM-HOLE LOCATION
INJECTION WELL BOTTOM-HOLE LOCATION
TOTAL VERTICAL DEPTH (TYP. 3 WELLS)
60' DEPTH
1800' DEPTH
2000' DEPTH
5500' DEPTH
6500' DEPTH
26" HOLE
17 1/2" HOLE
13 3/8" SURFACE CASING
20" CONDUCTOR
200'
12 1/4" HOLE
9 5/8" INTERMEDIATE CASING
24°
APPROX. 1100 LIN. FT. OF 7 INCH SCREEN
8 1/2" HOLE
GRAVEL PACK
2000' THROW
(Reference: "Planning and Design of Additional East Mesa Geothermal Test Facilities", TRW contract with ERDA)
TYPICAL EAST MESA WELL SECTION

Figure 3-9



CONDENSER
COOLING TOWER
SLICER TURBINE
SLICERS
ELECTRIC GENERATOR
5,000 KW
FEED PUMP
WASHER PUMP
INJECTION PUMP
WORKING FLUID LOOP
WORKING FLUID FEED PUMP
• GRANULATOR
• THIN JUICE HEATERS
• THIN JUICE BOILER
• WHITE PANS
• 2nd CARB HEATER
• LO RAW MELTER
• DIFFUSER
• HI RAW PANS
• HI RAW MELTER
• BLENDER
• THIN JUICE HEATERS
• RAW JUICE HEATER
• LO RAW PANS
• CONCENTRATOR
• THICK JUICE HEATER
• DIFF. SUPPLY TANK
• RAW JUICE HEATERS
15 PSIG (MIN) 1st EFFECT
7 PSIG (MIN) 2nd EFFECT
2 PSIG (MIN) 3rd EFFECT
6" Hg 4th EFFECT
10" Hg 5th EFFECT
EVAPORATORS
SUGAR REFINING
SUPERHEATER
BOILER
INJECTION PUMP
CONDENSATE RETURN PUMP
CONDENSATE
DOWN-HOLE PUMP
PRODUCTION WELL
INJECTION WELL
OPTION B — NEW PLANT
(GEOTHERMAL POWER/PROCESS)
STEAM
DRAFT FAN
FOSSIL FUEL BOILER
OPTION C — NEW PLANT
(GEOTHERMAL PROCESS)
(FOSSIL FUEL POWER)
GEOTHERMAL - SUGAR REFINING
NEW PLANT
GEOTHERMAL/FOSSIL FUEL
OPTIONS
TRW
ENVIRONMENTAL, POWER
AND FACILITIES DEPARTMENT
SYSTEM INTEGRATION LABORATORY
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APPRVD. – PROGRAM OFFICE
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Figure 3-10

Case I -- Resources under 300F - Typical of Imperial Valley, California, (Sedimentary)

Case II -- Resources under 300°F - Typical of Pacific Northwest and Mountain States (Volcanic)

Case III -- Resources between 300 and 350°F

Representative considerations for Cases I and II are indicated in Table 3-2.

The following conceptual designs, performance analyses and costs are based on the assumption that well fluid salinities are 25,000 ppm or less. In the event brines of higher salinities are encountered (e.g. Westmoreland or North Brawley well fluids), techniques other than chemical cleaning may be required and maintenance costs must be adjusted accordingly.

Figure 3-8 Well Configuration Alternatives

TABLE 3-2. CASE I AND II CONSIDERATIONS

ISSUE	CASE I	CASE II
SALINITY (TDS)	2,000 TO 300,000 TDS	200 TO 800 TDS
SOURCE TEMP	300 TO 400°F	150 TO 350°F
RESOURCE LONGEVITY		FRACTURE PERMEABILITY (LESS LIFE EXPERIENCE)
HEAT EXCHANGERS	• REDUNDANT FOR CYCLE/CLEAN • CONTINUOUS SCALE CONTROL	• LESS MAINTENANCE AND COST THAN CASE I
WELLS	• LONG TERM/MANY WELLS EXPERIENCE CERRO PRIETO, HEBER, EAST MESA • SAND SCREEN COMPLETION	• HIGHER DRILLING COSTS • MAY REQUIRE STIMULATION AND WORKOVER • CLAW FOOT COMPLETION
PROCESS APPLICATION	• INTERMEDIATE HEAT TRANSFER LOOPS • PROMISING TEMP TECHNICAL FEASIBILITY	• POTENTIAL USE CLEAN STEAM DIRECTLY • BORDERLINE TEMP TECHNICAL FEASIBILITY
EFFLUENT	• MUST REINJECT	• POTENTIAL USE FOR IRRIGATION

3.4.4 Holly Sugar - Brawley Factory Retrofit

Beet pulp drying and provision of medium pressure make-up process steam have been identified as promising applications for geothermal heat in a beet sugar factory. Conceptual designs of boilers and dryers were synthesized and analyzed which led to a selected cascaded boiler to dryer optimum configuration. This selected application approach was then adapted conceptually to a retrofit of the Holly/Brawley sugar factory as described below.

3.4.4.1 Steam Generation

The 34% exhaust (approximately 75,000 lbs/hr) make-up steam at the Holly Brawley factory that would normally be supplied by throttling live boiler steam can be supplied by a geothermal boiler. The preferred design would be to boil potable water in the boiler shell by flowing brine through the boiler tubes. The one expected problem area of scaling deposits on tube interiors can be satisfactorily covered by periodic chemical cleaning.

A preliminary steam boiler design and study was made by Southwestern Engineering. This study was based on using 300°F geothermal brine to deliver 75,000 lb/hr of steam at 25 psig (268°F) with an 0.002 design fouling factor.

With 300°F brine and 1" O.D. carbon steel tubes, computer runs showed optimum velocities ranging from 4.3 to 7.4 ft/sec and brine pressure drops ranging from 3 to 9 psi. Boiler size varied from 78 to 84 inches in diameter and 43 to 49 feet in length as shown in Figure 3-1.

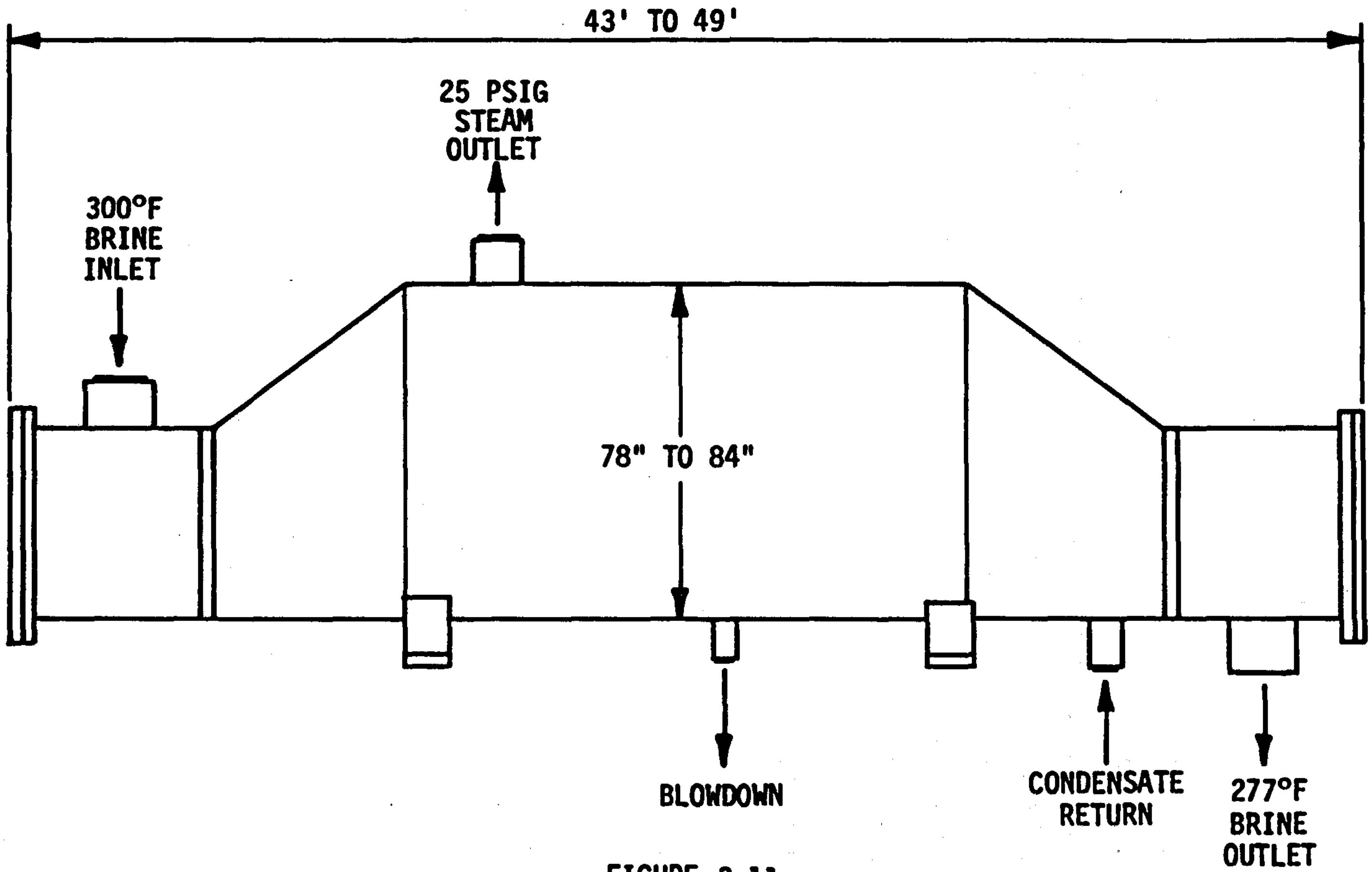


FIGURE 3-11

GEOTHERMAL BOILER
75,000#/HR OF STEAM
(Reference: Appendix A)

The required brine flow is plotted versus boiler heat exchanger surface and cost in Figure 3-12. The optimum selection criteria is the boiler surface providing the lowest geothermal brine flow rate and highest temperature drop (greatest energy use) because the wells are significantly more costly than the boiler, by an order of magnitude. The optimum configuration is a boiler with 20,300 square feet of heating surface with a brine inlet flow requirement of approximately 2,600,000 lbs/hr (5,875 GPM) and a boiler brine outlet temperature of 274.8°F. This brine flow demand could possibly be accomplished with five geothermal production wells.

The San Diego Gas and Electric Company recently performed an extensive test program on subscale heat exchangers using geothermal brine of approximately 355°F and 14,500 ppm dissolved solids at Heber, California as work sponsored by the Electric Power Research Institute. These salinities are similar to those experienced at East Mesa and anticipated on the fringes of the Brawley anomaly near the Holly factory. The report, EPRI No. 376 dated September 1975 is titled, "Test and Evaluation of a Geothermal Heat Exchanger."

The tube (four)-in-shell heat exchangers were assembled as four sections in series and three common tube materials - titanium, carbon steel and 90% copper - 10% nickel were tested.

After 560 hours of testing, the titanium tubes showed no corrosion and the carbon steel tubes showed slight pitting and decarburization. After 200 hours, the copper-nickel tubes had some corrosion and it was evident they corroded at a much more rapid rate than the carbon steel tubes.

300° GEOTHERMAL BRINE

25 PSIG STEAM BOILER

75,000 LBS/HR

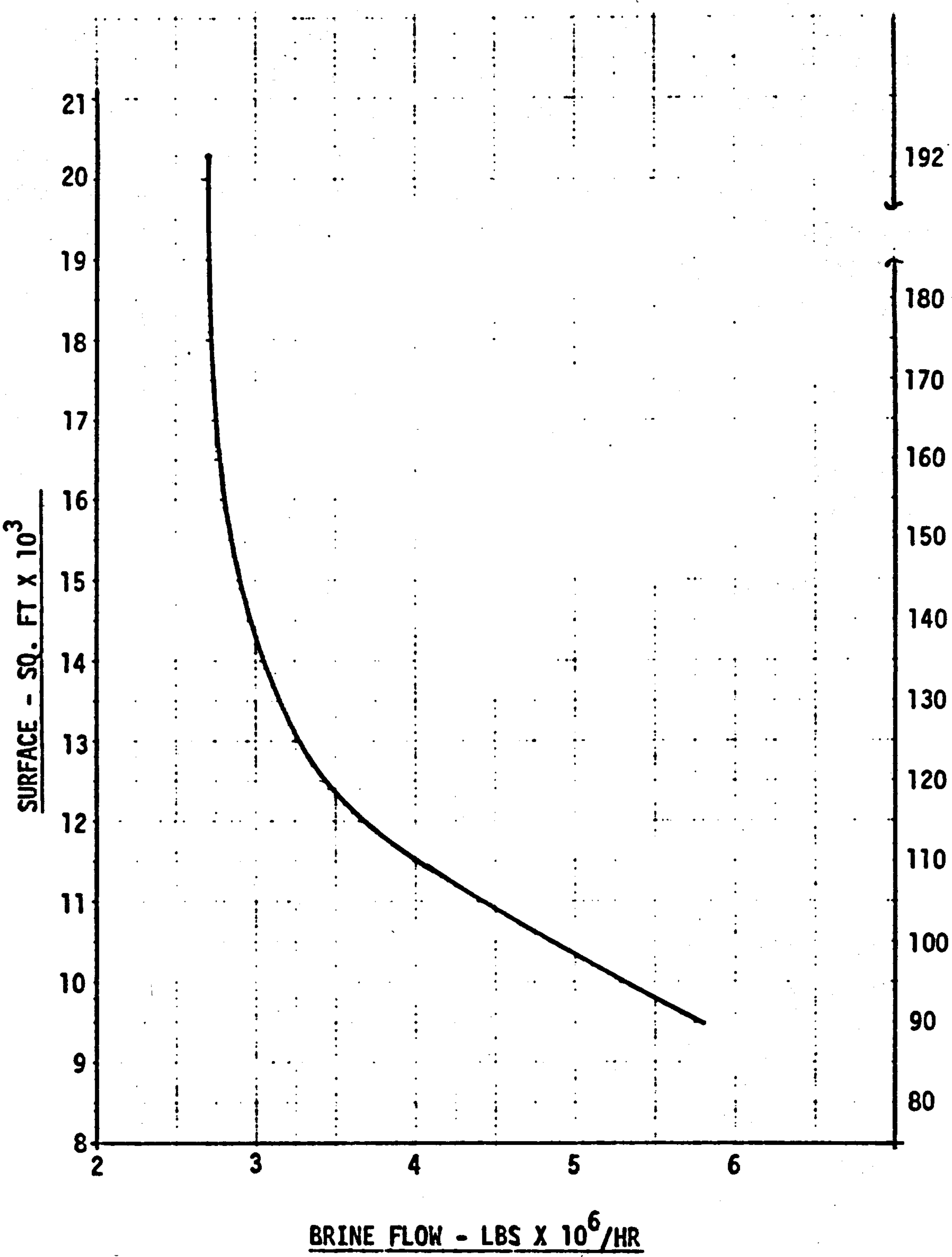


FIGURE 3-12 BRINE FLOW VS BOILER SURFACE/COST

The tests indicated that the scaling rate is primarily a function of brine velocity and that a heat exchanger system will perform best at velocities of 5 to 7 ft/second and at a minimum brine exit temperature of 150°F. Pressure losses with scale deposit build-up is essentially the same in either titanium or carbon steel tubes and will not be prohibitive over normal operating intervals. Heat transfer coefficients decline with time regardless of tube material and brine velocity.

Figure 3-13 indicates reduction of boiler capacity due to fouling will be minimum at the selected design flow rate of 2,600,000 lb/hr. Anticipated boiler operations between cleanings is in excess of 30 days.

Final test results showed that carbon steel tubes would be entirely satisfactory and very close to titanium tubes in performance characteristics. The choice of carbon steel tubes over titanium tubes in a full size exchanger will affect material cost savings of from 22 to 75%. Engineering and installation costs would be the same.

Up to 1/8" thick scale deposits can be removed by pumping a 50% caustic solution at room temperature through the heat exchanger tubing at a velocity of approximately 0.2 ft/sec for 15 to 30 minutes. This could cause some degradation in mild carbon steel tubes and therefore an acid cleaning solution may be more appropriate. Solutions can be reclaimed and reused at least six times.

The recommended boiler configuration for development and demonstration testing should include one inch O.D. carbon steel tubes. Long duration tests are required to establish scale buildup and performance impact with the design conditions identified for this application.

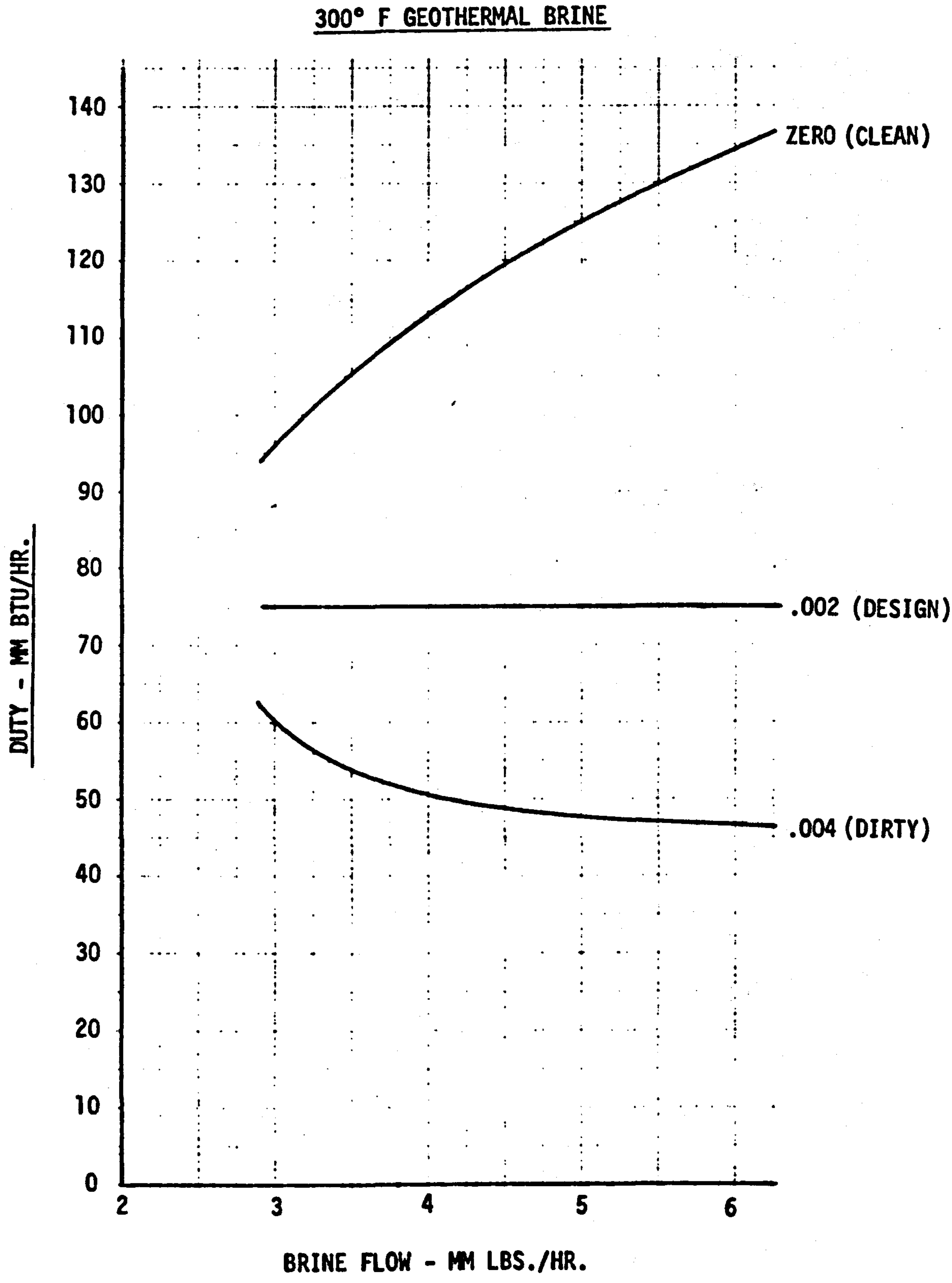


FIGURE 3-13 BOILER CAPABILITY VS FOULING

3.4.4.2 Pulp Drying

As previously stated, beet pulp drying, which accounts for from 30 to 50% of plant fuel demand, offers a great opportunity for fuel savings by switching to geothermal energy.

Many manufacturers of various types of commercial food/grain dryers were contacted. While none had ever supplied dryers using geothermal brine at 300°F for drying, most felt it could be done and gave preliminary estimates of retrofit equipment. All were in agreement as to the necessity of a demonstration/test program on a subscale dryer to provide backup data for a full scale design. Most were interested in participating in the program.

A list of the manufacturers contacted is as follows:

Rotating drum with brine coil at air inlet	Heil Co., Milwaukee, Wisconsin Applied Equipment Co., Van Nuys, Calif.
Rotating drum with brine tubes in drum	Stansteel Corp., Los Angeles, CA Swenson Evaporator Co., Harvey, Illinois
Rolling Tube	Sterns-Roger Co., Denver, Colorado
Continuous Conveyer	Proctor & Schwartz, Philadelphia, PA
Fluid Bed	Tailor & Co., Bettendorf, Iowa
Desiccant Dehumidifier	Dry Air, Inc., Sunbury, Ohio

Since conflicting performance predictions were received from some of the dryer manufacturers a separate analysis was performed in-house to develop a better understanding of the process with low drying temperatures.

In order to predict the performance of a low-temperature dryer, it was necessary to obtain some properties of the pulp in the dryer which were not available in the literature. These properties are the heat transfer between the drying stream and the pulp (Btu/hr-lb pulp-°F) and the evaporation rate from the pulp (lb-H_2O/hr-psi-lb pulp). Approximate values of these two coefficients were obtained by analyzing present high-temperature dryers (Figure 3-14 and using the resulting values to predict low-temperature dryer performance (Figure 3-15.

As expected, the results show that a low-temperature dryer, while capable of delivering a product with the required moisture content, is much less effective than a high-temperature dryer. Specifically, for the same volumetric flow of the drying stream, the rate of flow of pulp is reduced by a ratio of five to six, and the required residence or dwell time of the pulp in the dryer is increased by a factor of four to five as indicated in Figure 3-16.

These results coincide with one dryer manufacturer's estimates of a total of 16 dryers to replace the existing three fossil-fueled units at the Brawley factory.

The recommended drying approach considers a three pass rotating drum dryer (of the type manufactured by the Heil Co.) modified with a geothermally heated air drying coil as shown in Figure 3-17 This three pass approach appears to accomplish the increased dwell time required with minimum overall space requirements.

Increased efficiency in the use of geothermal fluids for the beet pulp dryers can be accomplished by preheating the supply air with the heat energy of the dryer warm air exhaust. This can be accomplished by placing a finned tube economizer coil in the 150°F dryer air exhaust stream as shown in Figure 3-17 Water in the tubes would be heated to 122°F and pump circulated in a closed pipe system to the finned tubes of a preheat coil located in the path of the air supply, upstream of the main geothermal brine heating coil. The preheat coil would heat the 70°F air supply to 106°F. The water, now 78°F, would return to the economizer coil to be reheated and the cycle repeated.

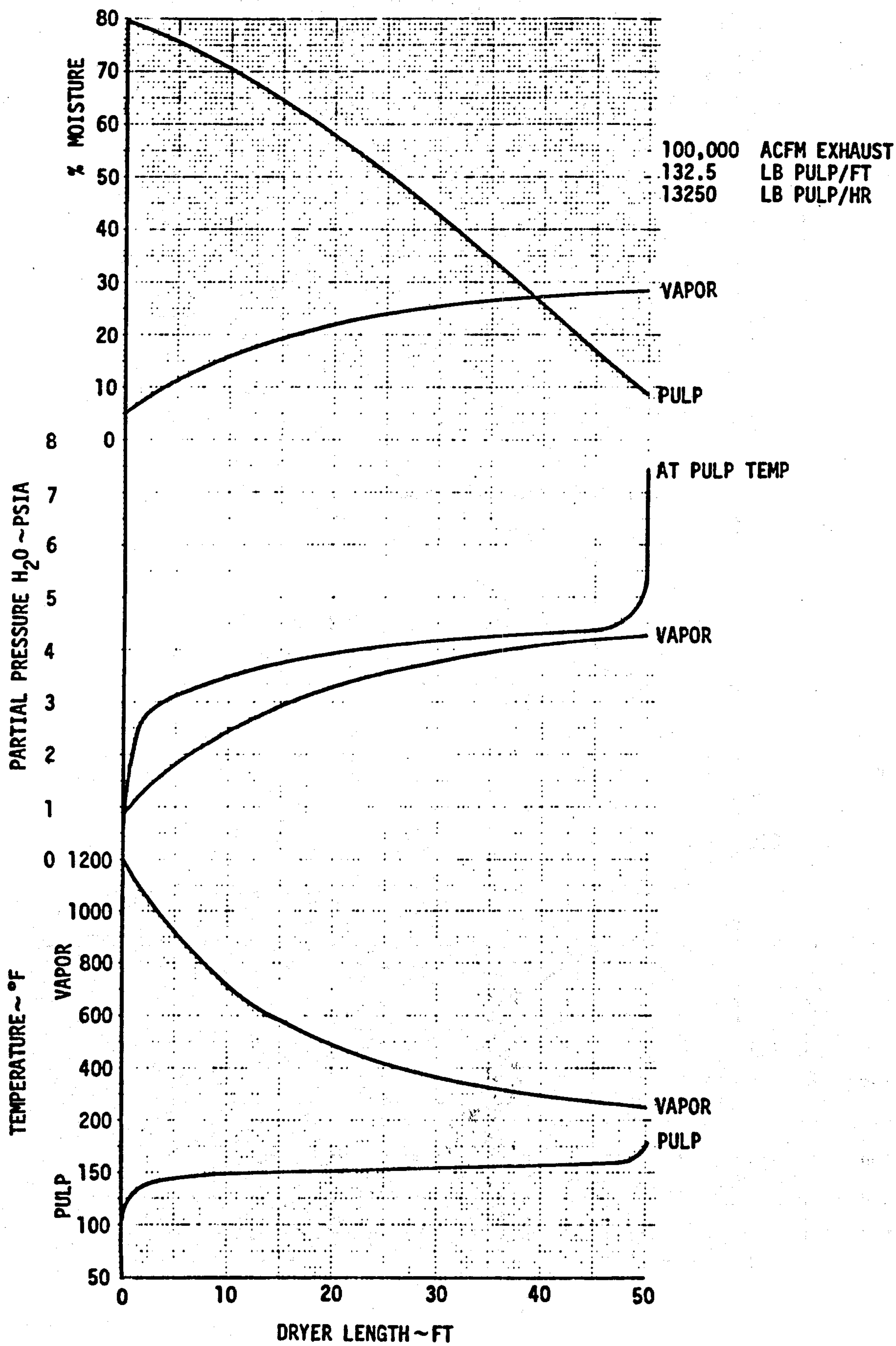


FIGURE 3-14 HIGH TEMPERATURE DRYER TEMPERATURE & MOISTURE PROFILES

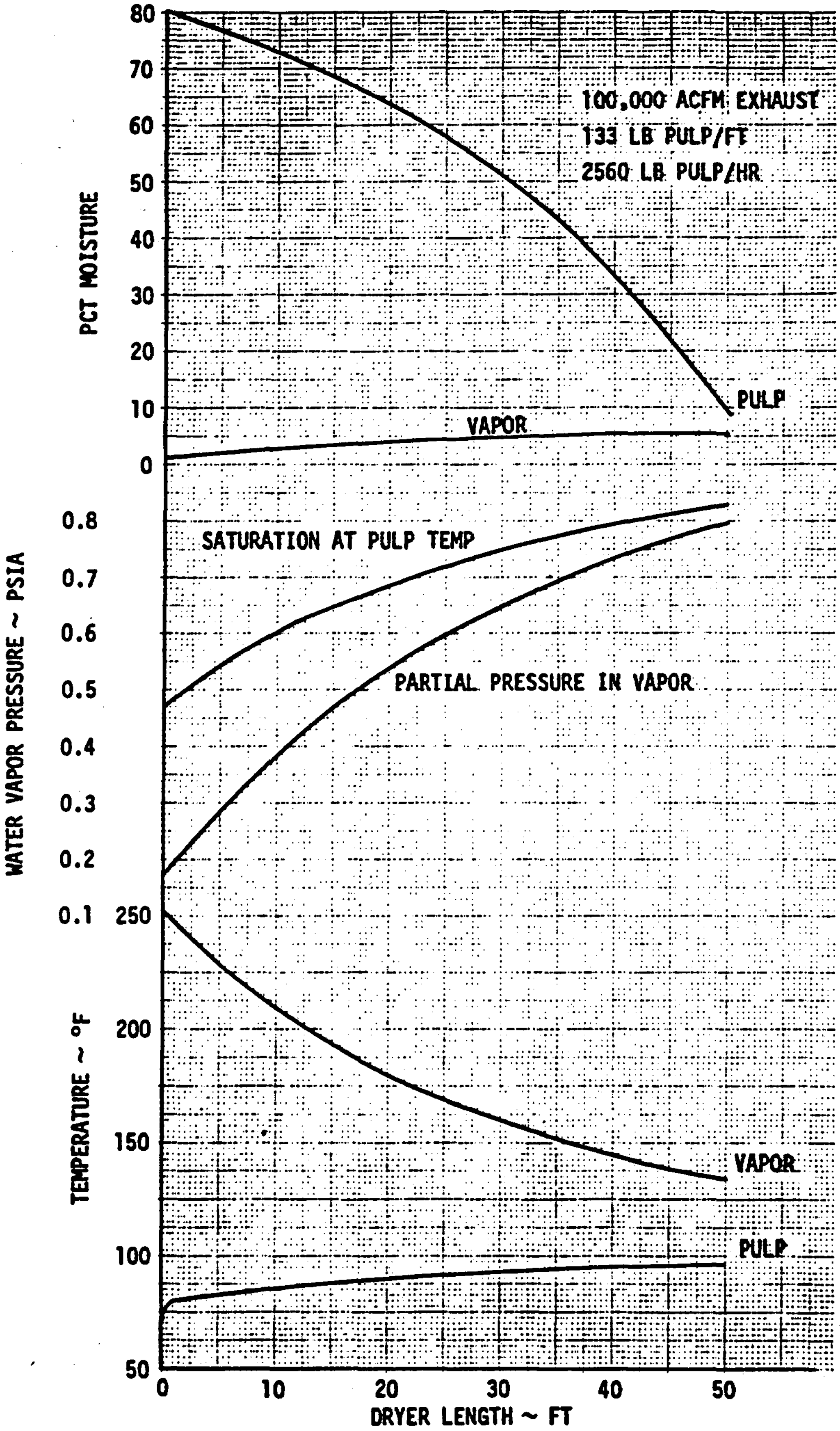


FIGURE 3-15 LOW TEMPERATURE DRYER TEMPERATURE & MOISTURE PROFILES

EFFECT OF INLET TEMPERATURE
ON LOW TEMPERATURE DRYER PERFORMANCE

DRYER SPECIFICATIONS:

100,000 ACFM EXHAUST
80% MOISTURE INLET
9% MOISTURE OUTLET
132.5 LB PULP/FT
50 FT LONG, 10.5 FT DIAM

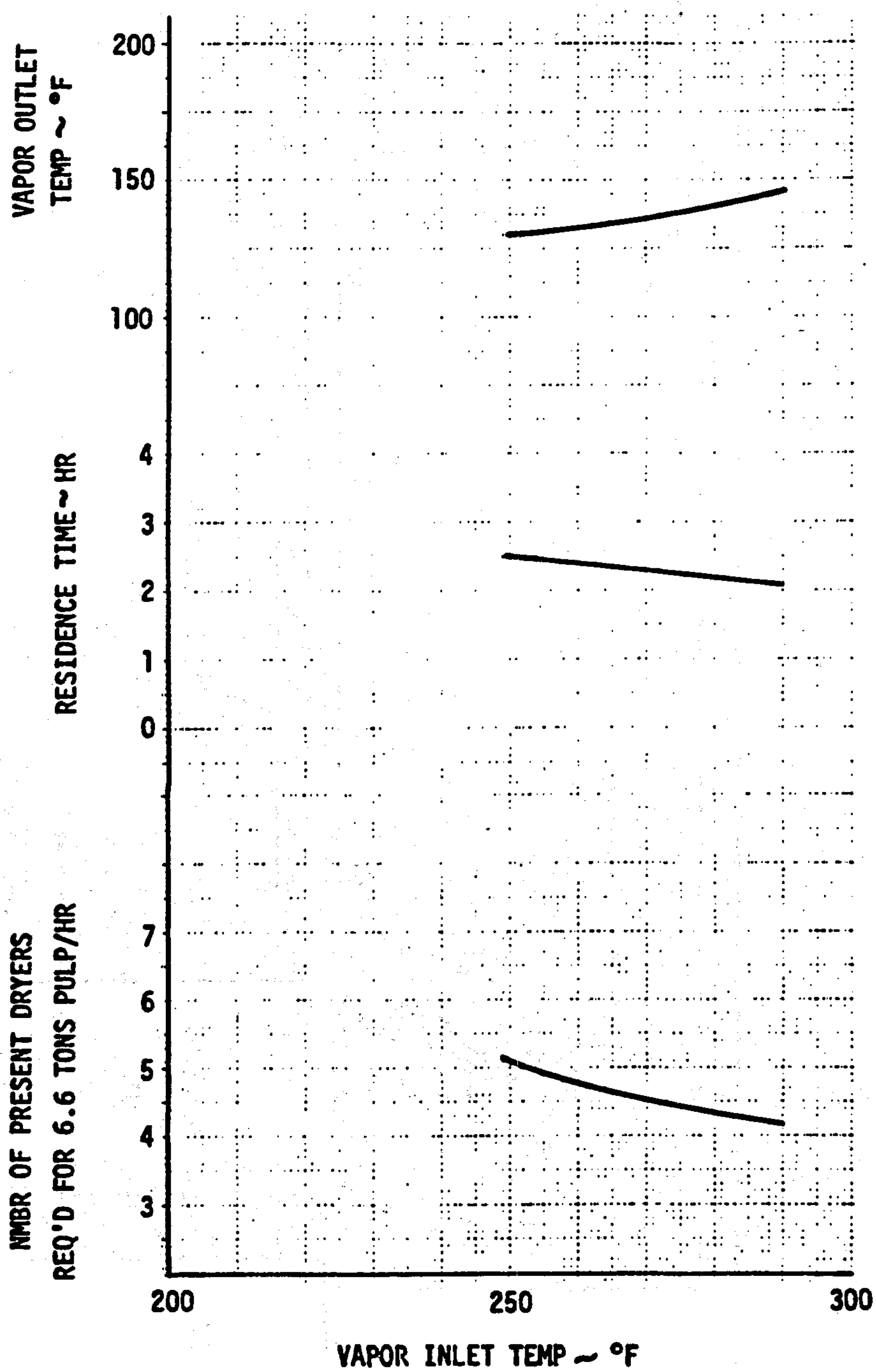
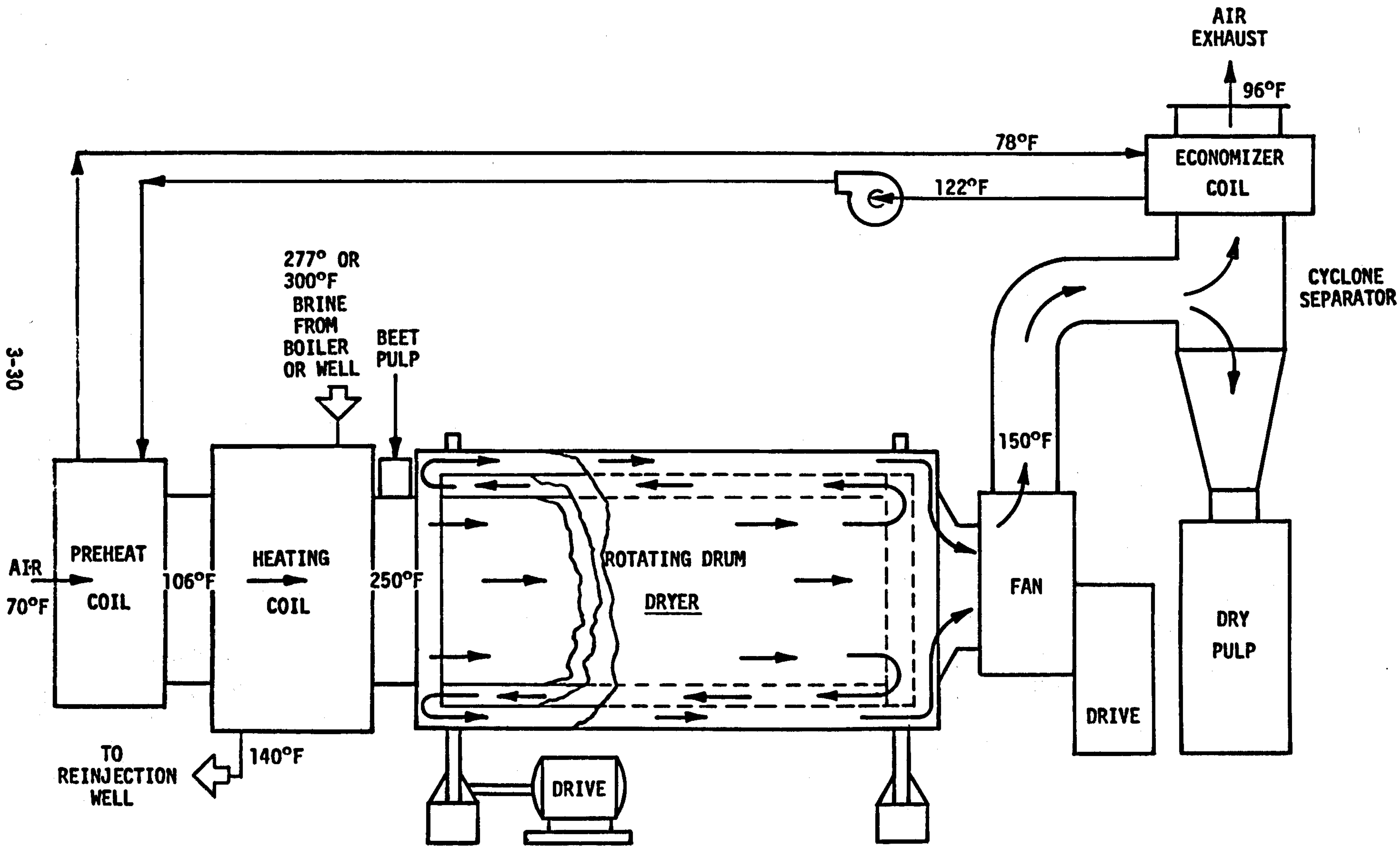


FIGURE 3-16 EFFECT OF INLET TEMPERATURE ON LOW TEMP DRYER PERFORMANCE

FIGURE 3-17

GEOTHERMAL SUGAR BEET PULP DRYER



This system reduces the required heat for the main heating coil and results in a lower geothermal brine flow rate which translates into a lesser number of the costly geothermal wells having to be drilled. Energy savings of twenty percent can be realized by the addition of a heat recovery system at each pulp dryer.

3.4.4.3 Cascading

Geothermal fluid can be used most advantageously by cascading from one type of usage requiring the high initial temperature into a second type of usage able to use a lower temperature. Cascading can utilize more thermal energy and therefore result in higher efficiencies and the lowest cost per million BTU's.

Cascading at Holly/Brawley can be accomplished from steam boilers to beet pulp dryers as indicated in Figure 3-18. The brine would first be used in the boilers to produce the required amount of 25 psig steam (from water other than the brine). From there the existing brine, now at a lower temperature of around 275°F, would be run through the main heating coils of each beet pulp dryer to heat incoming atmospheric air to 250°F. The heated air would then move and mix through the rotating drum dryer to absorb the entrained moisture and dry the pulp. The brine, now down to 140°F, would be returned to a reinjection well.

3.4.4.4 Brawley Sugar Factory Retrofit

Brine pipelines from offsite supply and reinjection wells (Figure 3-19 could be run underground along the south shoulder of the east-west private road of the Holly property adjacent to fenced north factory boundary as shown in Figures 3-21 and 3-21. Branch takeoffs from these main headers would be routed underground to the retrofitted geothermal steam boilers and bank of sixteen geothermal pulp dryers. Manual and automatic valving together with distribution and by-pass pipe manifolding would be provided to allow the dryers to operate as a cascade downstream of the steam boilers or independent of the boilers as

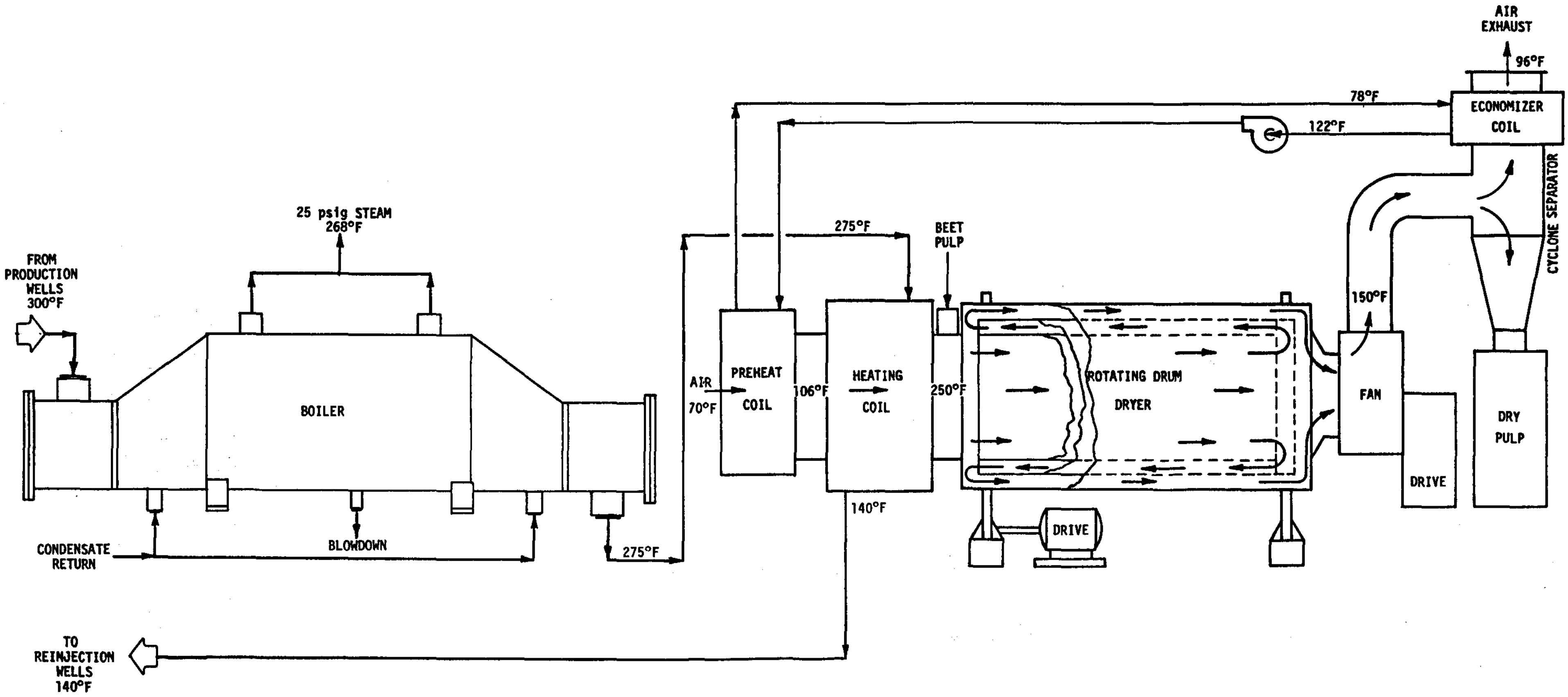


Figure 3-18 Cascade Boiler to Beet Pulp Dryer Schematic

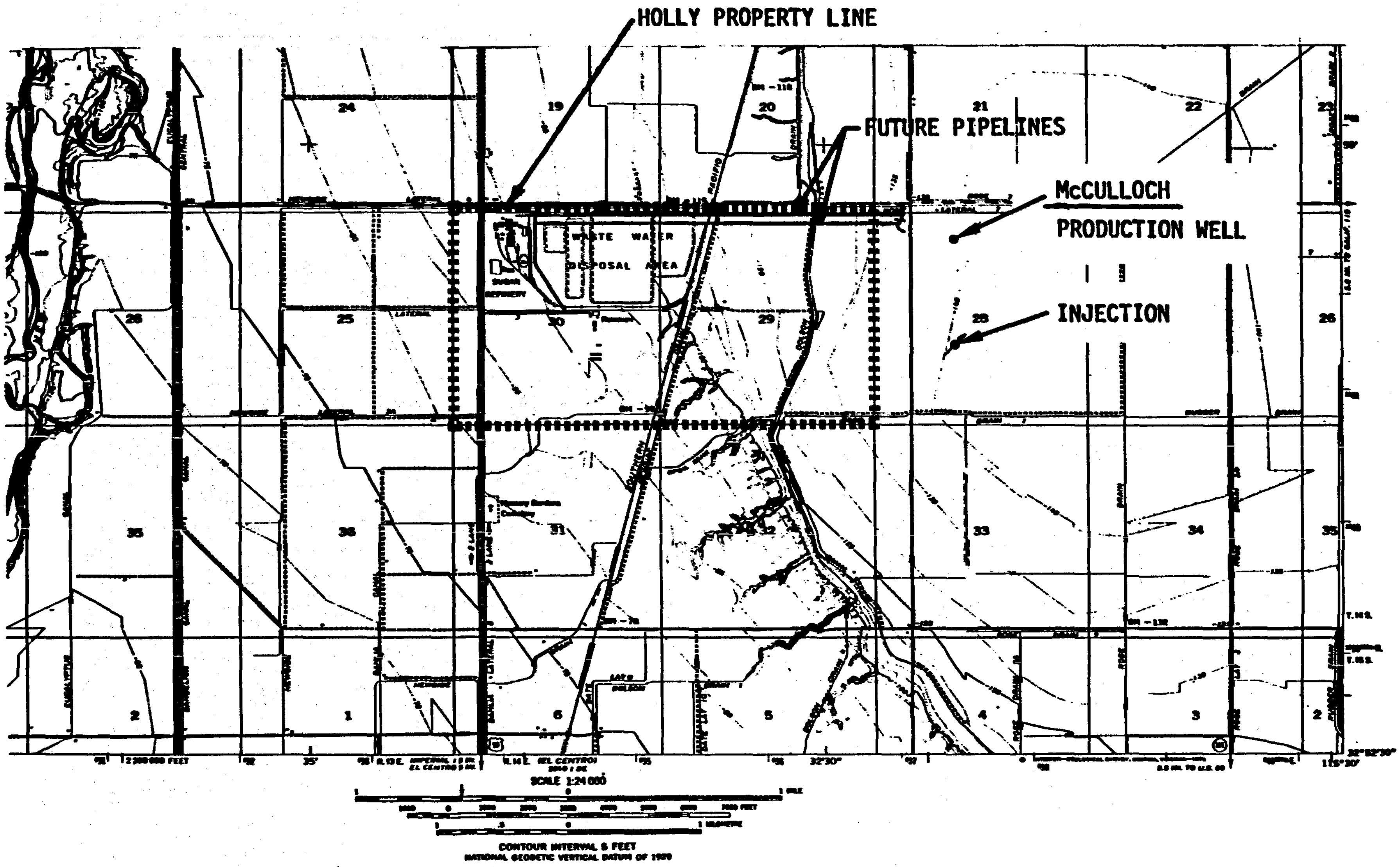
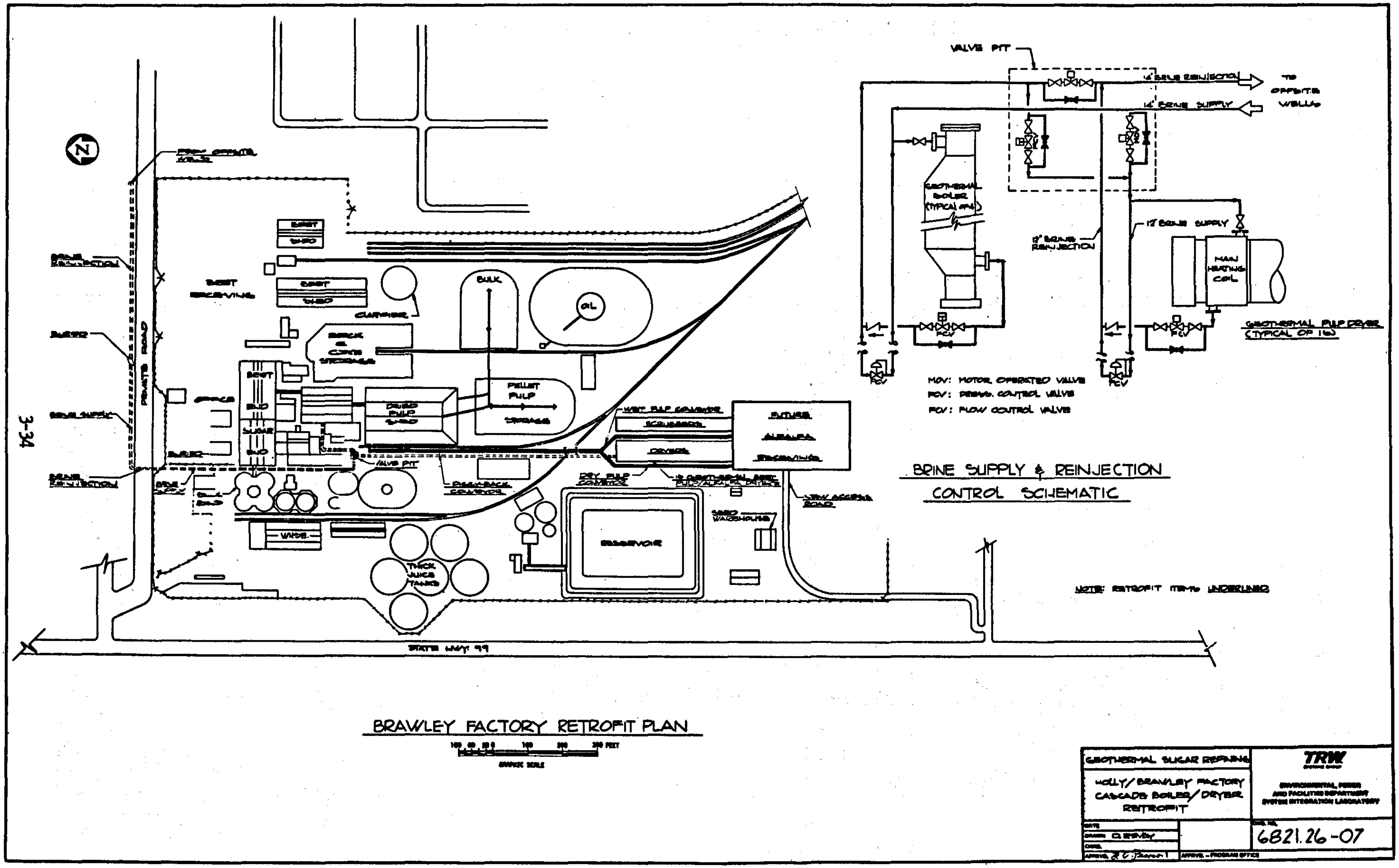


FIGURE 3-19 PLANNED GEOTHERMAL WELL DRILLING

(Pending ERDA approval of pending geothermal loan guaranty application)



BRAWLEY FACTORY RETROFIT PLAN
STATE HWY 99
RESERVOIR
THICK JUICE TANKS
BULK
OIL
PELLET PULP STORAGE
DRIED PULP SHED
BEET RECEIVING
FUTURE ALFALFA RECEIVING
SCRUBBERS
DRYERS
VALVE PIT
BRINE SUPPLY & REINJECTION CONTROL SCHEMATIC
14" BRINE REINJECTION
14" BRINE SUPPLY
TO OFFSITE WELLS
GEOTHERMAL BOILER (TYPICAL OF 4)
12" BRINE REINJECTION
12" BRINE SUPPLY
MAIN HEATING COIL
GEOTHERMAL PULP DRYER (TYPICAL OF 16)
MOV: MOTOR OPERATED VALVE
PCV: PRESS. CONTROL VALVE
FCV: FLOW CONTROL VALVE
NOTE: RETROFIT ITEMS UNDERLINED
GEOTHERMAL SUGAR REFINING
HOLLY/BRAWLEY FACTORY CASCADE BOILER/DRYER RETROFIT
TRW
6821.26-07

Figure 3-20

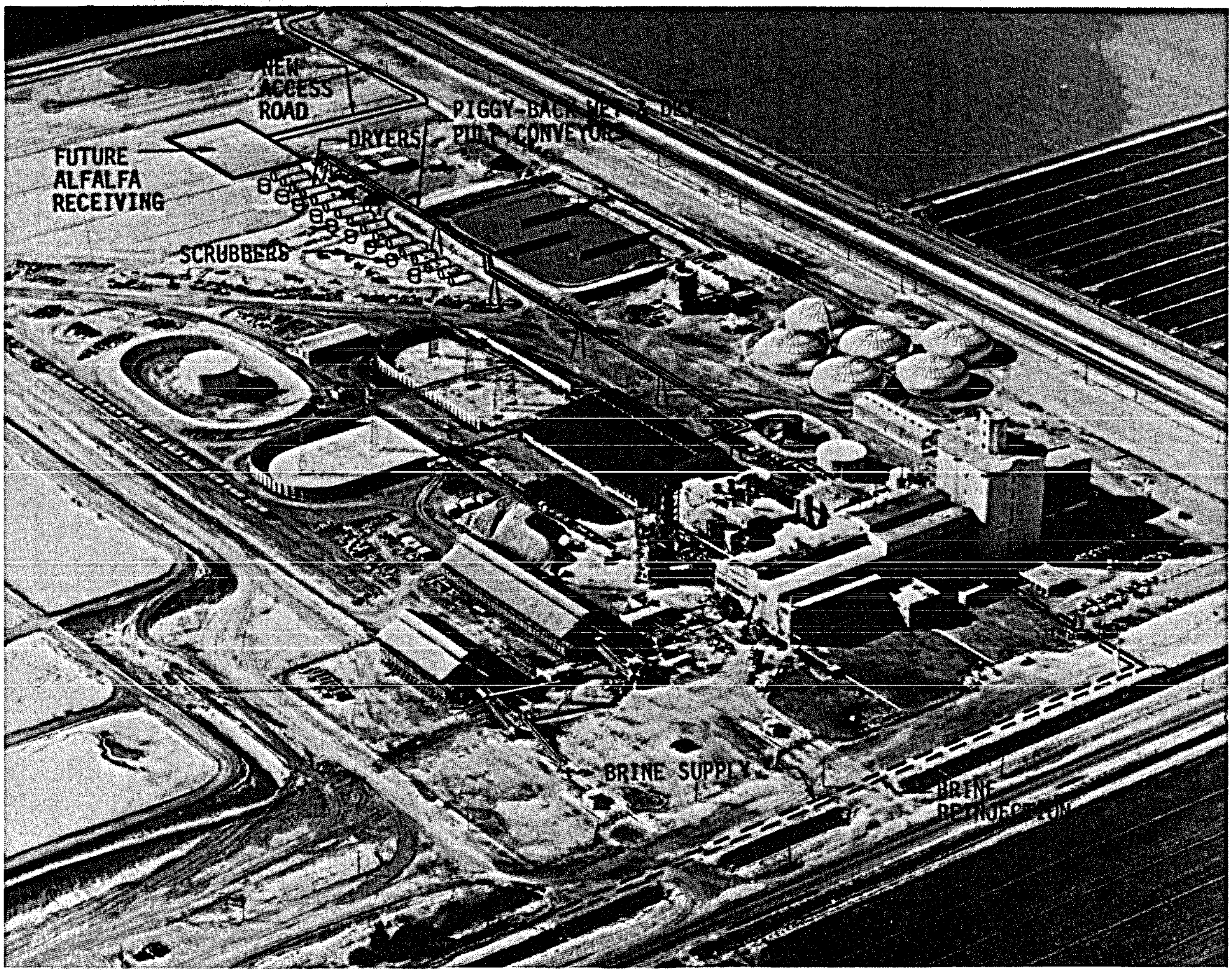


Figure 3-21 Aerial View Holly Retrofit Concept

shown schematically in Figure 3-10. Either boiler or any dryer could be shut down without affecting the operation of the remaining boiler or dryers. Flow control and motor operated valves for proper cascade brine flow balance from the boilers via the reinjection pipeline to reinjection well and to dryer brine supply would all be contained in a covered grade level concrete valve pit. Pressure control valves would be located in the end of the brine supply-reinjection loop for both the boilers and dryers to provide flash preventing back pressure.

The location for the geothermal dryers has been selected for loading convenience of other than beet pulp drying (e.g., alfalfa) and the need of a larger area to accommodate the sixteen units. The existing pulp presses would have to be relocated adjacent to the new dryers and new conveyors would be installed to move the wet pulp from the slicing area to the presses as shown in Figure 3-10. Dried pulp would be collected from the dryers on a covered conveyor and routed to a covered shed housing the relocated pelletizer. From there the pellets would be moved on a covered conveyor to the outdoor pellet storage area.

3.4.4.5 Brawley Factory - Geothermal Application Potential

The retrofit and new factory potentials for geothermal applications to the Holly Sugar, Brawley Factory are shown in Table 3-3. As shown, the retrofit potential reduction of fuel oil demands is approximately 65% and new factory potential reduction approximately 86%.

TABLE 3-3 HOLLY SUGAR BRAWLEY FACTORY — GEOTHERMAL APPLICATION POTENTIAL

	CAMPAIGN EQUIVALENT FUEL DEMANDS		RETROFIT POTENTIAL		NEW FACTORY POTENTIAL	
FACTORY DEMAND	%	BARRELS OF OIL	GEOTHERMAL 300°F	BBL/OIL	GEOTHERMAL 300°F	BBL/OIL
LIVE STEAM TO SLICERS (1)	2.2	7,730	---	7,730	* (PART)	2,300 (COMP)
TURBINE EXHAUST STEAM TO PROCESS (2)	20.4	71,820	---	71,820	*	---
THROTTLED MAKEUP STEAM TO PROCESS (2)	25.1	88,180	*	---	*	---
ELECTRICAL GENERATION (2)	10.2	35,580	---	35,580	---	35,580
TURBINE MECHANICAL DRIVES (2)	1.9	6,840	---	6,840	---	6,840
SUGAR COOLING REFRIGERATION (2)	0.8	2,840	*	---	*	---
PULP DRYERS (1)	39.4	138,350	*	---	*	---
TOTALS	100.0	351,340		121,970		44,720

(1) 126 DAYS IN 1976 HOLLY/BRAWLEY CAMPAIGN

(2) 174 DAYS IN 1976 HOLLY/BRAWLEY CAMPAIGN

3.0 REFERENCES

3-1 R. A. McGinnis, Beet-Sugar Technology, Beet Sugar Development Foundation.

4.0 CAPITAL, OPERATING AND MAINTENANCE COST COMPARISONS

Total costs of candidate geothermal application approaches have been developed for comparison with conventional fossil-fuel supply costs. The total geothermal costs are developed to include effects of capital, operating and maintenance costs. The annual fixed charge rate of 21.6% was calculated using commercial money rates, depreciation factors and tax rates of fourth quarter 1976 as a present value basis. Geothermal costs are developed in dollars per million BTU's as a comparison basis with the fossil fuels; e.g., Brawley fuel oil costs for the 1976 campaign were $\$2.23/10^6$ BTU's. The costs developed in this task as inputs for the economic evaluations of Task 6 are based on the retrofit Brawley factory conceptual designs described in Section 3 and summarized in the following sections.

4.1 Sugar Factory Capital Costs

Capital costs for a typical sugar beet processing plant are shown in Table 4-1. Cost data was obtained from Holly Sugar and apply to a typical plant processing 6000 tons of sugar beets per day such as the Holly plant at Brawley. Capital costs shown in Table 4-1 have been escalated to 1976 prices. As this table depicts, a typical plant can cost approximately 64 million dollars.

4.2. Energy Supply Costs

The capital costs of supplying geothermal energy to the sugar refining process can be divided into those capital costs associated with wells and transmission of the geothermal fluid to the sugar refining process.

4.2.1 Wells - Capital Costs

Energy supply costs for a typical geothermal system are based on capital cost estimates developed for East Mesa geothermal fluids in previous TRW studies for the Bureau of Reclamation (Ref. 4-1), ERDA (Ref. 4-2) and the National Science Foundation (Ref. 4-3). These costs are shown in Table 4-2. As indicated, these costs are based on well, piping and pump costs. The estimated cost factors for land acquisition, exploration and environmental impact represent approximately 9 percent of the total. The costs shown in Table 4-2 apply to a geothermal system and injection wells all drilled

Table 4-1 SUGAR BEET PROCESSING PLANT COSTS

(TYPICAL 6,000 T/DAY PLANT - 1976 COSTS)

		APPROXIMATE COST	%
BEET END OPERATIONS	=	$16,000,000	25
SUGAR END OPERATIONS	=	12,160.00	19
PULP PRESSING AND DRYING	=	7,680,000	12
STEAM AND POWER GENERATION	=	7,680,000	12
SUGAR STORAGE AND HANDLING	=	7, 680,000	12
SITE IMPROVEMENTS	=	12,800,000	20
(LAND, WELLS, FIRE PROTECTION, ROADS, DRAINAGE, MISC. BUILDINGS)			
TOTAL	=	$64,000,000	100

Table 4-2. NOMINAL ENERGY SUPPLY CAPITAL COST ESTIMATE (Third Quarter 1976)

Item	Description	Cost	Basis
1	Production Well and Tree	$400,000	Vertical 6,500 ft depth 2,000 ft 13-3/8 4,500 ft 9-5/8 1,000 ft slotted Gravel pack 20 acre spacing
2	Injection Well (Prorated)	266,700	Ratio 3:2
3	Sub-Total (ST)	$666,700	
4	Piping	66,670	f = 0.10
5	Downhole Pump	72,000	1,000 GPM 20 MD 60% EFF
6	Injection Pump (Surface)	47,500	1,000 GPM 20 MD 60% EFF
7	Land Acquisition (leasing, fees)	40,000	f = 0.06
8	Exploratory Holes (3 or 4 Success)	13,300	f = 0.02
9	Surface Exploration	20,000	f = -.03
10	Environmental Impact	13,300	f = 0.02
	Total Capital Cost per 1,000 GPM	$939,500	

Note: Total f = 1.41 (basis 2 to 6 production wells)
f = Well factored estimate after Tester (Ref. 4-4).

vertically to a depth of 6500 feet, pumping 1000 gallons of 350°F fluid per minute. Capital costs shown in this table are for the third quarter of 1976 (Ref. 4-2 and 4-4). As can be seen, the capital costs for this type of system would be slightly less than one million dollars.

Table 4-3 shows assumed annual fixed charge rates for geothermal fluids. For estimating purposes, the fixed costs of the energy supply system were assumed to be an annual fixed charge rate on the capital investment required for wells. The assumed annual fixed charge is 21.6 percent and includes minimum acceptable returns on capitalization (debt and equity) income taxes (California and Federal) and miscellaneous factors including estimated administrative and general expenses, insurance, ad valorem taxes and a depreciation sinking fund annuity.

An example of the translation of estimated capital costs and assumed annual fixed charge rates into comparative prices (costs) are shown for East Mesa geothermal fluids as tabulated in Table 4-4. The energy value potential for use of geothermal fluids, such as East Mesa, is favorable when compared to current most probable fuel costs such as the Brawley fuel oil costs for the 1976 campaign of $\$2.23/10^6$ BTU's.

4.2.2 Transmission Costs

Transmission pipeline costs are demand dependent and are therefore developed in conjunction with application cost evaluations as described in paragraph 4.4.4.

4.3 Electrical Costs

To assist in comparing costs between a total geothermal system, a total fossil fuel system and a combined fossil fuel/geothermal system, electrical generating costs for 300°F and 350°F brines are presented in Table 4-5. This economic data can be used for evalutating the replacement of the following:

- total replacement of the fossil fuel boiler system (geothermal energy provides both process heat and electrical energy)
- partial replacement of the fossil fuel boiler system (geothermal energy provides only process heat)
- no replacement of the fossil fuel boiler system (fossil fuel provides both process heat and electrical energy)

Table 4-3 ANNUAL FIXED CHARGE RATE ASSUMPTIONS

	ASSUMPTION*	RATE (%)
COST OF MONEY		--
FRACTION OF CAPITAL IN BONDS	42%	
INTEREST RATE ON BONDS	8%	3.4
FRACTION OF CAPITAL IN EQUITY	58%	--
RETURN ON EQUITY	15%	8.7
TAX RATES	--	5.3
MISCELLANEOUS		
ADMINISTRATION AND GENERAL		
INSURANCE		3.5
ADVALOREM TAXES		
SINKING FUND (DEPRECIATION)	20 YR	0.7
		21.6%

* REF. 4-5

Table 4-4 ESTIMATED GEOTHERMAL PRICES (COSTS)

ASSUME

- DEMAND FACTOR OF 80 PERCENT (7,008 HRS/YEAR)
- HEAT EXTRACTED 350°F TO 250°F AT 1,000 GPM

THEN

ANNUAL FIXED CHARGES	$\left(\frac{939{,}500 \times 21.6\%}{7008} \right)$	=	\$28.96
MAINTENANCE	$\left(\frac{939{,}500 \times 0.5\%}{7008} \right)$	=	0.67
OPERATING PUMPS	(500 KW AT 30 MILLS/KWH)	=	15.00
FLUID COST/HR OF OPERATION			\$44.63

GEOTHERMAL FLUID COST (250°F to 350°F) = $ $0.89/10^6$ BTU

Table 4-5 GEOTHERMAL ELECTRICAL GENERATION COST ESTIMATES

WELLHEAD TEMPERATURE --	300°F	350°F	400°F
UNIT PLANT COST(1) FOR 50MWe NET PLANT	\$520/KW	\$490/KW	\$460/KW
ESTIMATED UNIT COST(1) FOR 5MWe NET PLANT (ADD 50%(3))	\$780/KW	\$735/KW	\$690/KW(3)
WATER RATE, LB/HR PER KW	275	150	110
UNIT WELL COST(1) AT \$1.25 PER LB/HR(2)	\$345/KW	\$190/KW	\$140/KW
TOTAL UNIT COST(1)	\$1125/KW	\$925/KW	\$830/KW
DIRECT CAPITAL COSTS(1) FOR 5MWe NET PLANT & WELLS	\$5.6 M	\$4.6 M	\$4.2 M
TOTAL CAPITAL COSTS FOR 5MWe (ADD 25% FOR ENG., ADMIN., ESCALATION)	\$7.0 M	\$5.8 M	\$5.2 M
MILLS/KWH AT 80% PLANT FACTOR, 20% CAPITAL CHARGE	44	36	34

(1) DIRECT CAPITAL COSTS ONLY Ref. 4-6

(2) E.G., A \$500 K WELL FLOWING 400K LB/HR

(3) SOURCE: HAWAIIAN ELECTRIC ESTIMATES

Table 4-5 shows costs of electricity generated from geothermal energy. The data in this table applies to the total geothermal system only since both the energy for process heat and electrical generation would be replaced.

4.4 Brawley Factory Retrofit Concept

The following costs were developed as inputs for the economic evaluations of Section 6 based on the retrofit Brawley factory conceptual designs described in Section 3.

4.4.1 Geothermal Boiler

The costs of generating the make-up steam for the Brawley factory with different boiler configurations, is indicated in Table 4-6 for the study criteria, 300°F geothermal brines. As indicated, lower brine flows have a more beneficial cost impact than boiler first costs as developed in Figure 3-2. Also, it is noted that the minimum cost ($\$4.40/10^6$ BTU's) with the boiler as the sole brine user, is not competitive with fuel oil costs of $\$2.23/10^6$ BTU's. However, with geothermal brines at 350°F, as shown in Table 4-7, the single use boiler costs of $\$1.76/10^6$ BTU's look particularly attractive.

4.4.2 Beet Pulp Dryer

The costs of drying beet pulp with rotary air dryers using geothermal brines at 300°F are shown in Table 4-8 for a range of supply air and brine outlet temperatures. As noted, the costs are marginally competitive for all applications considered.

4.4.3 Cascade Boiler/Dryers

Tables 4-9 and 4-10 show what happens when either 300°F or 350°F brine is cascaded first through the 25 psig steam boiler and then through the beet pulp dryers. In these modes the cost per million BTU's is \$3.10 for 300°F brine and \$2.22 for 350°F brine. The economics really look attractive if the cascaded dryers can be operational beyond the sugar

Table 4-6

SUGAR BEET REFINING - 25 PSIG STEAM GENERATOR

300°F GEOTHERMAL BRINE -- 75,000 LB/HR STEAM

BRINE FLOW		HEAT LOAD BTUH $\times 10^6$	BRINE		BOILER		WELLS		PUMPING COSTS 3¢/KWH $/HR	BOILER COST $/HR*	TOTAL COSTS $/HR	COST PER MILLION BTU'S $
#/HR $\times 10^6$	GPM		ΔT °F	TEMP OUT °F	SURF. SQ FT $\times 10^3$	COST EA $ $\times 10^3$	NO.	COST $/HR				
5	10879	70.05	13.6	286.4	10.35	98.5	10	545.5	23.4	15.8	584.7	8.35
4	8703	70.05	17	283	11.5	110.3	8	436.4	18.7	16.9	472	6.74
3	6727	70.05	22.7	277.3	14.3	138	6	327.3	14	17.8	359.1	5.13
2.7	5875	70.05	25.2	274.8	20.3	192	5	272.7	12.6	22.5	307.8	4.40

Costs are based on 21.6% AFC and 3,960 hours (5-1/2 months) operation.

*Includes 35% installation, est. piping, valving, instrumentation and 2% yearly maintenance.

Table 4-7

SUGAR BEET REFINING - 25 PSIG STEAM GENERATOR

350°F GEOTHERMAL BRINE -- 75,000 LB/HR STEAM

BRINE FLOW		HEAT LOAD BTUH $\times 10^6$	BRINE		BOILER		WELLS		PUMPING COSTS 3¢/KWH $/HR	BOILER COST $/HR*	TOTAL COSTS $/HR	COST PER MILLION BTU'S $
#/HR $\times 10^6$	GPM		ΔT °F	TEMP OUT °F	SURF SQ FT $\times 10^3$	COST EA $ $\times 10^3$	NO.	COST $/HR				
1	2243	70.05	66.7	283.3	7	70	2	109	4.8	9.3	123.1	1.76
1.2	2691	70.05	55.6	294.4	5	50	2	109	5.8	7.7	122.5	1.68
1.4	3139	70.05	47.7	302.3	4.4	44.3	3	163.6	6.8	7.4	177.8	2.54
1.6	3588	70.05	41.7	308.3	4.3	42.5	3	163.6	7.7	7.4	178.8	2.56

Costs are based on 21.6% AFC and 3,960 hours (5-1/2 months) operation.

*Includes 35% installation, est. piping, valving, instrumentation and 2% yearly maintenance.

Table 4-8

Sugar Beet Pulp Replacement Dryers

300°F Fluid - Holly/Brawley

Temp. Air °F	Airflow per Dryer SCFM	Temp. Brine Out °F	Flow Brine per Dryer GPM	No. Coil Rows/Dryer R-21 10'6"L	No. Coil Rows/Dryer R-21 11'L	No. Coil Rows/Dryer R-24 12'L	No. Dryers Total	Flow Brine Total GPM	No. Geo. Wells Total	Est(4) Cost Dryers Total $ x 10^6	Est(5) Cost Wells Total $ x 10^6	Est(6) Cost Total $/hour	Heat Load Total BTUH x 10^6	Cost per Million $
		200	428	14	14	12		5564	5		5	629.6		2.46
290(1)	82,714	170	329	18	16	14	13	4277	4	3.25	4	552.4	255.5	2.16
		140	267	22	22	20		3471	3		3	475.3		1.86
		200	394	10	10	8		5516	5		5	648.3		2.56
270(2)	83,828	170	303	12	12	10	14	4242	4	3.5	4	571.1	253.5	2.25
		140	246	14	14	12		3444	3		3	494.0		1.95
		200	360	8	8	6		5760	5		5	685.8		2.59
250(3)	85,135	170	277	8	8	8	16	4432	4	4	4	608.5	264.8	2.30
		140	225	10	10	10		3600	3		3	531.5		2.01

(1) 4.2 units to replace one existing dryer.

(2) 4.56 units to replace one existing dryer.

(3) 5.11 units to replace one existing dryer.

(4) Based on $250,000 each including coil.

(5) Based on $1,000,000 each.

(6) Includes: Cost of dryers & wells @ 21.6% AFC & pumping cost @ 3¢/KWH - (no operation, pump or pipe transport costs) 4 months (2880 hours)/yr operation.

Table 4-9

HOLLY/BRAWLEY CASCADED GEOTHERMAL SYSTEM

300°F BRINE

CASCADE SEQUENCE	HEAT USED BTU's x 10"		COSTS - $\$ \times 10^3$							
	EACH	TOTAL	WELLS	BOILER	DRYER	OPER'G*	MNT*	WELL* OPER	TOTAL*	$ PER MILLION BTU's
Boiler - 5-1/2 Mos	2.774	8.979	5,000	386.4	5,622	0	7.73	49.9	2,783	3.10
Beet Dry - 4 Mos	6.205					235	112.44			
Boiler - 5-1/2 Mos	2.774	18.286	5,000	386.4	5,622	0	7.73	72.9	3,158.7	1.73
Beet Dry - 4 Mos	6.205					587.83	112.44			
Alfalfa Dry - 6 Mos	9.308									

*Operating and Maintenance costs are yearly, as is the total. Well, Boiler and Dryer costs are total capital (installed). Yearly cost was calculated at 21.6% AFC.

Based on four boilers (192,000 x 1.2/4) @ $57,600 each.

Table 4-10

HOLLY/BRAWLEY CASCADED GEOTHERMAL SYSTEM

350°F BRINE

CASCADE SEQUENCE	HEAT USED BTU's x 10"		COSTS - $\$ \times 10^3$							
	EACH	TOTAL	WELLS	BOILER	DRYER	OPER'G*	MNT*	WELL* OPER	TOTAL*	$ PER MILLION BTU's
Boiler - 5-1/2 Mos Beet Dry - 4 Mos	2.774 6.137	8.911	3,000	135.8	4,567.81	0 191.04	2.72 91.36	29.5	1,978.01	2.22
Boiler - 5-1/2 Mos Beet Dry - 4 Mos Alfalfa - 6 Mos	2.774 6.137 9.206	18.117	3,000	135.8	4,567.81	0 477.61	2.72 91.36	53.64	2,288.73	1.27

*Operating and Maintenance costs are yearly, as is the total. Well, Boiler and Dryer costs are total capital (installed). Yearly cost was calculated at 21.6% AFC.

beet campaign for other drying such as alfalfa. If these dryers can be kept in use for 10 months out of the year, the cost per million BTU's drops cost effectively to $1.73 for 300°F brine and $1.27 for 350°F brine. This last mode is identified as the optimum approach for the use of geothermal energy in sugar refining.

4.4.4 Transmission Pipeline Costs

Transmission pipeline costs per mile of buried insulated pipeline are summarized for each Brawley retrofit concept using 300°F and 350°F brines in Tables 4-11 and 4-12 respectively.

4.4.5 Holly/Brawley Retrofit Cost Summary

The costs of Brawley factory retrofit applications using 300°F and 350°F geothermal brines, from wells located adjacent to the planned McCullogh wells, are summarized in Table Table 4-13.

Table 4-11

HOLLY/BRAWLEY GEOTHERMAL ENERGY SUPPLY COSTS

300°F BRINE

Item	No. Wells	No. Dryers	Flow GPM	Heat BTU's	Time		Pipe In.	Pumping $	Pipe & Pumps* $	Total $	1 Mile Pipe $/BTU x 10^6
					Mos.	Hrs.					
1. Steam	5		5875	2.774×10^{11}	5-1/2	3960	14	99,870	893,400 80,000	310,125	1.12
2. Drying	3	13	3471	$6{,}14 \times 10^{11}$	4	2880	12	42,912	813,120 70,000	233,666	0.38
3. Cascade	5	16	5875 3312	2.774×10^{11} 6.205×10^{11} 8.979×10^{11}	5-1/2 4	3960 2880	14	99,870	893,400 80,000	310,125	0.35
4. Cascade Alfalfa	5	16	5875 3312	2.774×10^{11} 15.513×10^{11} 18.287×10^{11}	5-1/2 10 4-1/2	3960 7200 3240	14	99,870 46,065 145,935	893,400 80,000	356,190	0.20

*Total Capital x 21.6% = AFC + Pumping = Total

Table 4-12

HOLLY/BRAWLEY GEOTHERMAL ENERGY SUPPLY COSTS

350°F BRINE

Item	No. Wells	No. Dryers	Flow GPM	Heat BTU's	Time		Pipe In.	Pumping $	Pipe & Pumps* $	Total $	1 Mile Pipe $/BTU x 10^6
					Mos.	Hrs.					
1. Steam	2		2243	2.744×10^{11}	5-1/2	3960	12	38,129	813,120 70,000	228,883	0.83
2. Drying	2	13	2171	6.14×10^{11}	4	2880	12	26,840	813,120 70,000	217,594	0.36
3. Cascade	3	13	3139 3471	2.774×10^{11} 6.137×10^{11} 8.911×10^{11}	5-1/2 4	3960 2880	12	14,553 42,912 57,465	813,120 70,000	248,220	0.28
4. Cascade Alfalfa	3	13	3139 3471	2.774×10^{11} 15.343×10^{11} 18.117×10^{11}	5-1/2 10 4-1/2	3960 7200 3240	12	107,280	813,120 70,000	298,034	0.17

*Total Capital x 21.6% = AFC + Pumping = Total

Table 4-13

HOLLY/BRAWLEY RETROFIT SUMMARY

CAPITAL, OPERATING AND MAINTENANCE COSTS

			Cost $/Million BTU's*			
				2-1/2 Mile Transmission		
	Number of Wells	Number of Dryers	In-Situ Wells	Pipe Size	Piping Cost	Total Cost
300°F Brine						
Sugar Refining (5-1/2 Months)						
Make-Up Steam	5		4.40	14"	2.80	7.20
Pulp Drying	3	13	3.06	12"	0.95	4.01
Cascade Boiler to Dryer	5	16	3.10	14"	0.88	3.98
Seasonal						
Cascade Sugar (5-1/2 months) Alfalfa Drying (4-1/2 months)	5	16	1.73	14"	0.50	2.23
350°F Brine						
Sugar Refining (5-1/2 Months)						
Make-Up Steam	2		1.76	12"	2.08	3.84
Pulp Drying	2	13	2.69	12"	0.90	3.59
Cascade Boiler to Dryer	3	13	2.22	12"	0.70	2.92
Seasonal						
Cascade Sugar (5-1/2 months) Alfalfa Drying (4-1/2 months)	3	13	1.27	12"	0.43	1.70

*1977 costs, including amortized capital and operating and maintenance costs of wells, equipment and pipelines.

4.0 REFERENCES

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4-2 Planning and Design of Additional East Mesa Geothermal Test Facilities (Phase 1B), TRW Systems and Energy for ERDA, October 1976, Report No. 28653-6002-RU-00.

4-3 Experimental Geothermal Research Facilities Study (Phase 0), TRW Systems and Energy for ERDA, December 1974, Report No. 26405-6001-RU-00.

4-4 Milora, S. and Tester, J., Geothermal Energy as a Source of Electric Power, 1976, the MIT Press.

4-5 Bloomster, C. and Knutsen, C., the Economics of Geothermal Electricity Generation from Hydrothermal Resources, 1976, Battelle Pacific Northwest Laboratory Report BNNL-1989.

4-6 Utilization of U.S. Geothermal Resources, TRW Systems and Energy for Electric Power Research Institute, December 1976, Technical Planning Study 76-638.

5.0 THE SUGAR PROCESSING MARKET

5.1 Market History

From 1934 to 1974, sugar prices were held stable as a result of a legislated Sugar Act. Since 1974, when the Act officially expired, prices have no longer been regulated and stable, but have been fixed by supply and demand.

To compound this price stabilization problem, world forecasts shows that this will be the third year in a row with sugar production higher than consumption. Currently, the U.S. grows approximately 65 percent of our sugar requirement. Most other sugar producing nations have protective programs, which benefit both the producer and the consumer. Any excess sugar that is produced enters the world market.

Several other factors will have an effect on the current sugar market. First, corn sweeteners share of the market has increased faster than the overall market growth. Second, a survey conducted by the U.S. Department of Agriculture on January 1, 1977 shows that beet producers anticipate a 7 percent decrease in planting intentions. Last, the new association directory shows a reduction of at least 3 beet processing plants for 1977 operations. The instability of prices reflected in the current market, coupled with the worldwide overproduction of sugar, has resulted in a grim outlook for the sugar industry.

5.2 Potential Market Improvements

In January, 1977, Teno Roncalio (Democrat-Wyoming) introduced a new Sugar Act to Congress. The Act is similar to one introduced in September, 1976 in the House of Representatives (HR 15485). In addition to the promulgation of new legislation, it is possible that the President could impose an import quota on sugar to raise and stabilize its price.

The United States International Trade Commission is currently conducting hearings to ascertain the effect of quantities of foreign imported sugar at low prices on the domestic industry. Findings are to be reported to the President.

U.S. representatives have complained to the Commission that refined sugar is being sold at prices under the cost of growing and processing the beets. To make a living, they feel that sugar prices will have to improve. Without relief, farmers may be forced to switch from beets or cane to other crops that sell at more stable prices. However, factory owners do not have the option to convert their processing plants to some other process. They feel that some type of relief and protection is necessary for both the consumer and the producer during shortages and surpluses. U.S. representatives have stated that a sugar import quota would ease this problem by allowing higher prices for domestic sugar. Generally, the industry feels that imports are the cause of the problem and that only an import quota will improve sugar prices.

Foreign representatives stated to the Commission that it is not the worldwide overproduction of sugar that is hurting the market. They feel that the lower market is due to a decrease in consumption and the influx of high fructose corn syrup, and that this has hurt the industry worldwide. They would approve of U.S. legislation which would establish quotas and which would guarantee fair prices across the board. Perhaps an International Sugar Agreement would be effective in solving this problem.

Based on tests conducted by the Canadian government over the past three years on laboratory rats, saccharine was found to cause malignant bladder tumors in these test animals; therefore, unsafe for human consumption. As a result, the U.S. immediately announced that it would ban saccharine due to the provisions of the Delaney Clause of the Federal Food Drug and Cosmetic Act. Both the U.S. and Canada are planning to phase saccharine out gradually. Immediately after the ban was announced, the sugar market fluctuated mildly; however, this effect did not last very long.

Basically, there are two groups of people who use saccharine. First, is the group of people who medically are unable to ingest sugar or even high fructose corn syrup. Second, is the group of people who use saccharine to stay thin by eating low carbohydrate or sugar free foods.

In the U.S., per capita consumption of saccharine is about 8 pounds or about 5 million tons for the entire U.S. With the saccharine ban, it is possible that at most an additional 2-3 pounds of sugar might be consumed per capita in the U.S. The impact to the sugar industry is expected to be minimal, if any. Certainly, the ban would not result in enough economic motivation to cause the sugar industry to construct a new geothermally-fired sugar processing plant.

To stabilize sugar prices, President Carter recently approved sugar subsidies of up to 2 cents per pound. The subsidy is to be given to sugar beet and cane growers whenever the market price of sugar falls below 13.5 cents per pound. Since the money is to be paid by the U.S. Treasury Department, it should have no effect on the price paid by consumers. In turn, it is also not enough of an incentive to justify large capital expenditures on the part of the sugar industry at this time.

5.3 Geothermal Application Potential

Under existing conditions as described above and as iterated by each of the industry representatives contacted (Reference Section 10), there is little likelihood of any new beet sugar facilities being built in the geothermal potential areas of the western United States. Costs are high, and without sugar legislation the sugar price is not stable enough to project return on investment. However, there would be retrofit potential in areas where factories now exist and geothermal energy is readily available.

6. ECONOMIC EVALUATIONS

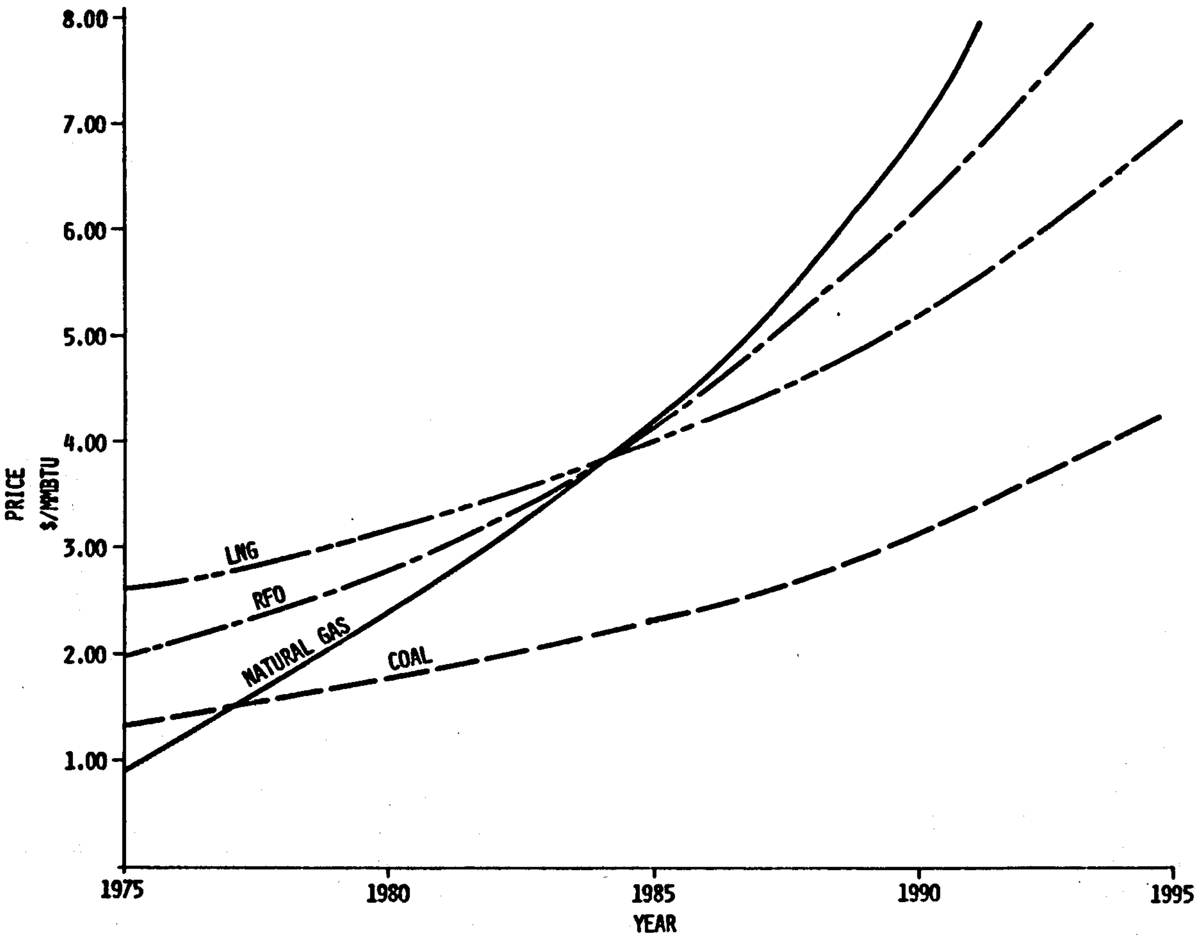
In Section 4, several economic bases were established. This section utilizes this data in cost comparisons and economic evaluations.

6.1 Fossil Fuel Costs

Currently, various types of energy sources are utilized by the sugar industry to supply energy for the refining process and the generation of electricity. These fuel sources include natural gas, residual fuel oil and coal. Figure 6-1 illustrates an estimate of the cost of these fuels as well as liquefied natural gas (LNG). These fuel costs have been projected to the year 1995 and are based on a combination of price increases due to general inflation and demand/supply influences. To account for general inflation, fuel costs have been escalated at the rate of six percent per year according to the Office of Management and Budget inflation estimates. Influences on fuel prices due to demand/supply have been accounted for by various estimates. In order to make direct comparisons of the different types of fuels, costs have been converted to dollars per million Btu's.

Coal is currently utilized to supply the process and electrical energy needs for the sugar industry in western states other than California. Air pollution regulations prohibit the burning of coal in California. The fuel cost shown in Figure 6-1 is based on the price paid for coal by U & I in 1976, escalated at 6 percent per year. Since coal reserves are considered plentiful and the demand fairly stable, the future price of coal is not expected to be influenced by demand/supply, but only by general inflation. However, it should be noted that the demand for coal may rise as a result of increased coal burning and gasification and liquefaction programs, depending on the energy policies of the present administration.

In California, since it is prohibited to burn coal and the supply of natural gas is dwindling, residual fuel oil (RFO) is the energy source currently being utilized in the sugar industry. Natural gas has been severely curtailed to industrial users in the past two years and trends indicate that the curtailment will continue to increase as supplies of natural gas diminish. Thus, industrial users, who no longer see natural gas as a reli-



FUEL PRICE PROJECTIONS

LEGEND

NATURAL GAS - CONSUMER (INDUSTRIAL) PRICES FOR GAS IN CALIFORNIA - ECONOMICS OF OIL AND GAS FOR USE IN CALIFORNIA. S.H. CLARK

LNG - SYNTHETIC FUELS COMMERCIALIZATION PROGRAM, VOL. III, AND S.H. CLARK

RESIDUAL FUEL OIL (RFO) - LOW SULFUR FUEL OIL, ELECTRIC UTILITIES STUDY, TRW SYSTEMS AND ENERGY.

COAL - 1976 U&I COSTS ESCALATED @ 6%/YEAR

Figure 6-1-Fossil Fuel Price Projections able energy source, are being forced into switching to RFO to meet energy needs. This switching trend to RFO will probably continue until 1984. In 1985, as shown in Figure 6-1, RFO and LNG are expected to become economically competitive with each other.

The natural gas curve shown in Figure 6-1 is based on prices mandated by the Federal Power Commission (FPC). As of January 1, 1977, the FPC set the price of new gas - gas supplies discovered, committed or put into production to interstate markets after January 1, 1975 - at $1.42 per thousand cubic foot (MCF). In addition, the FPC mandate allows producers to raise the price of new gas by another 4 cents per MCF per year. It should be noted that $1.00/MCF is roughly equivalent to $1.00/MMBtu. Since the supply of natural gas is decreasing, prices will increase due to both general inflation and demand and supply influences. It seems likely that prices will increase faster than the 4 cents per year increase allowed by the FPC. Gas prices may possibly be deregulated by the FPC and thus be subject to market pressures. If so, gas prices would be determined by supply and demand. Because of these factors, for 1977, the $1.42 price set by the FPC has been included on Figure 6-1. For subsequent years, S. H. Clark's (ref 6-1) estimate of gas prices to industrial users has been included. Clark's estimate is based on the price of natural gas determined by general inflation as well as by supply and demand. It should be noted that the $1.42 price for new gas has been used since "old" gas has not been available to industrial users.

The RFO curve shown in Figure 6-1 is derived from a previous TRW study performed for ERDA (ref 6-2). In this study, price projections were based on the Gulf Stanford Research Institute and the FEA-PIES models. Price projections are for low sulfur residual fuel oil delivered to California users. The price of foreign crude oil is determined by the Organization of Petroleum Exporting Countries (OPEC). Estimates of future crude oil prices are difficult to ascertain since prices are often determined by political decisions. The demand for crude oil is growing and it is not expected that OPEC will increase production at the pace necessary to meet the projected demand. The TRW study has estimated that world-wide RFO prices will rise at a rate of 2 percent per year in real terms (supply/demand) more than the general worldwide rate of inflation, which has been included in the RFO curve.

6.2 Geothermal and Fossil Fuel Cost Comparisons

In Section 4, it was determined that providing 300°F geothermal heat to either the boiler or the beet pulp dryer only, without cascading, was not economical. Further, it was established that the most attractive adaptation of geothermal energy to the sugar refining process is a system in which heat is cascaded from the boiler to the beet pulp dryer.

Therefore, this section utilizes the economic data developed in Section 4 for various combinations of sugar refining systems and geothermal fluid temperatures to determine which system appears to be the most economical. In addition, each system is compared to the fossil fuel price projections developed in Section 6.1 to determine when geothermal energy will be competitive with fossil fuels. Systems to be analyzed and compared include:

1) Cascade - 300°F Geothermal Fluid

2) Cascade/Off-Season Use - 300°F Geothermal Fluid

3) Cascade - 350°F Geothermal Fluid

4) Cascade/Off-Season Use - 350°F Geothermal Fluid

Figures 6-2 through 6-4 show price projections of each of the four alternative geothermal systems in comparison to fossil fuel price projections. Costs have been projected to the year 1995 in order to show when geothermal energy will become economically competitive with any fossil fuels (coal, natural gas, oil or LNG).

All geothermal curves have been derived by first estimating the 1976 cost of providing geothermal energy to the refining process for each of the four systems. Second, the derived geothermal costs were escalated from 1976 to 1980 at the 6 percent inflation rate set forth by the Office of Management and Budget. 1980 is the earliest possible point in time for initial operation as determined in Section 11. Until operation begins in 1980, all associated costs will be subject to inflation; however, after 1980, only overhead and maintenance costs will be influenced by inflation. The rationale for this was developed in Section 4 and data is incorporated in Figures 6-2 through 6-4.

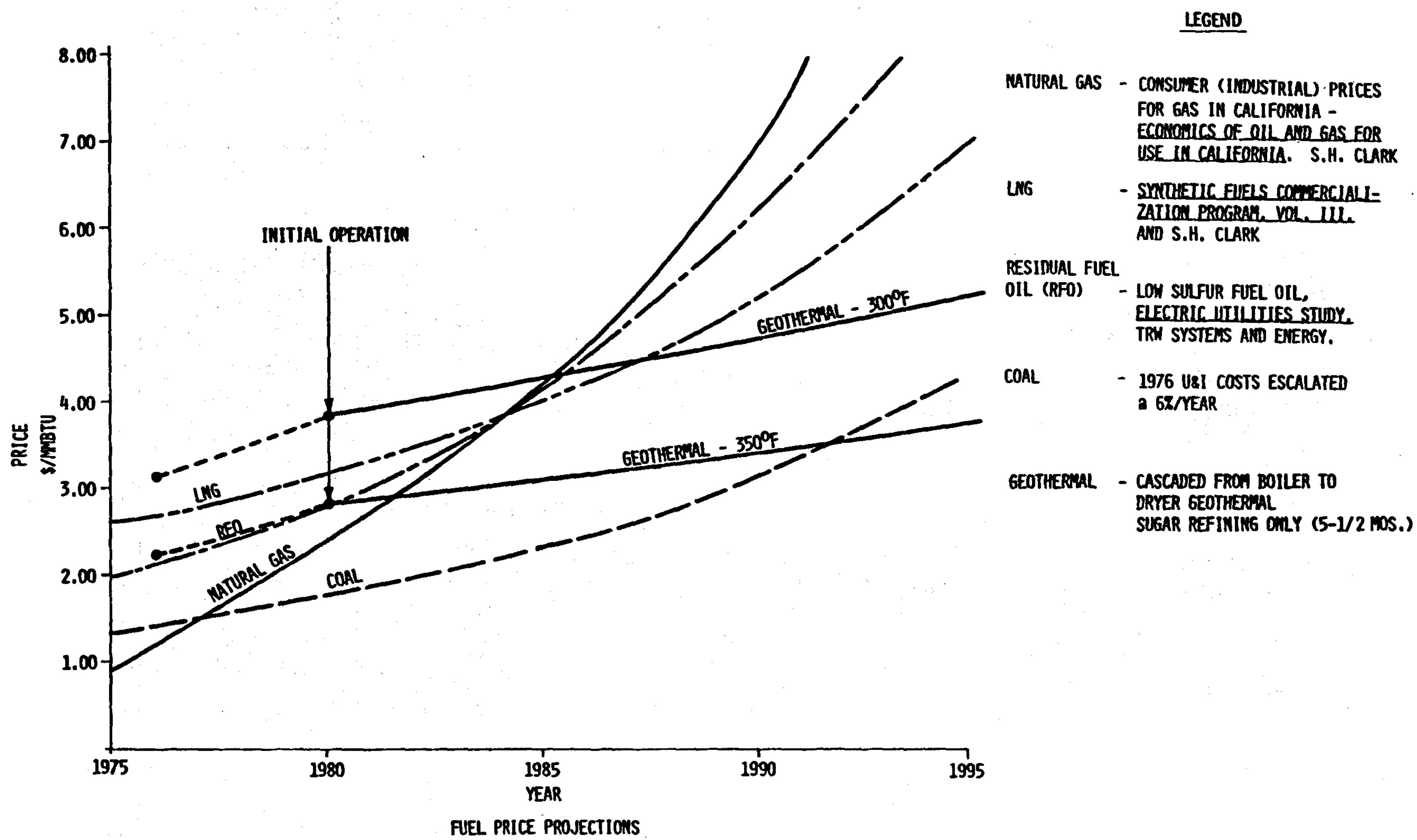


Figure 6-2 - Fuel Price Projection Comparisons of Cascaded 300°F and 350°F Geothermal Systems to Fossil Fuels

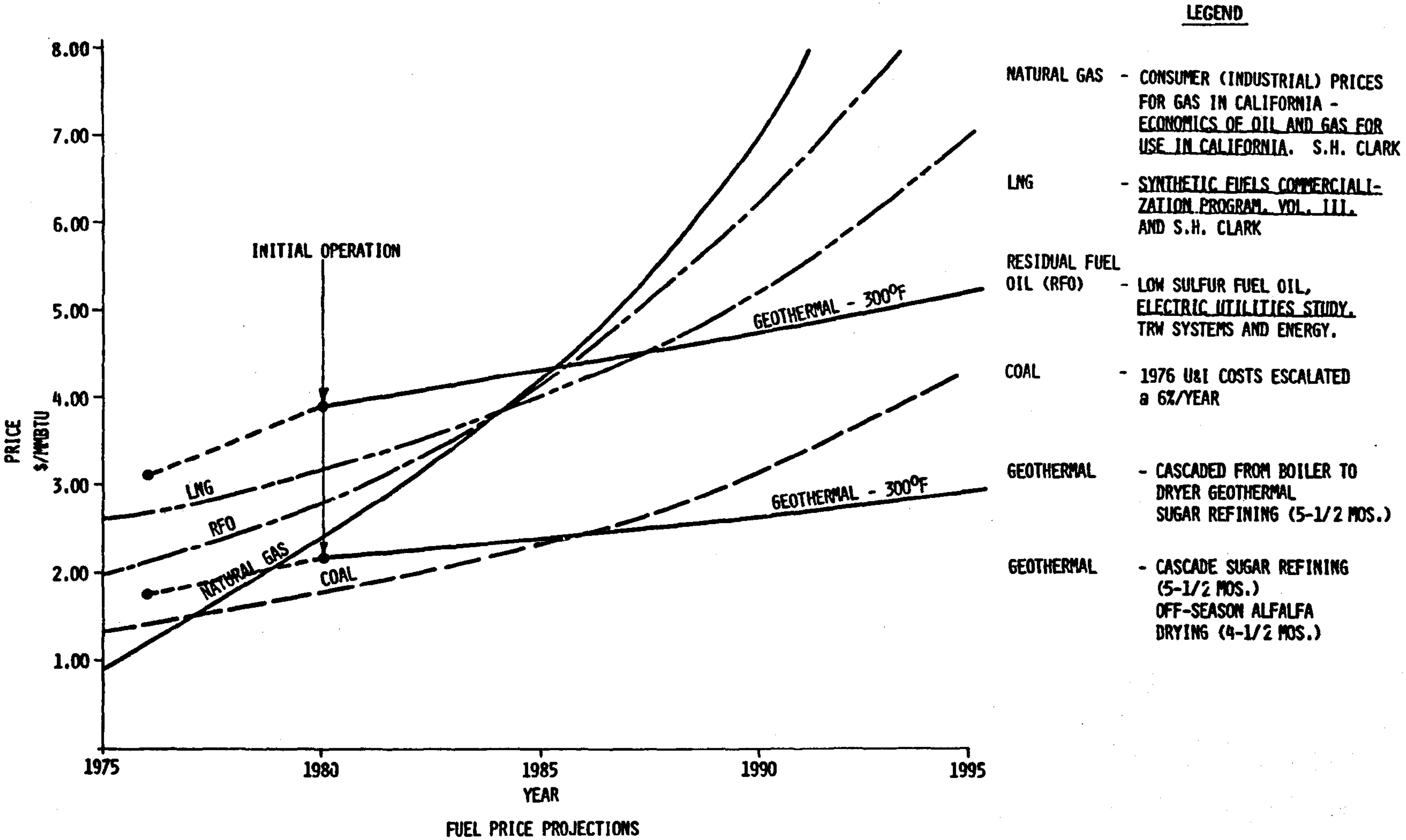


Figure 6-3 - Fuel Price Projection Comparisons of 300°F Cascaded and Cascaded/Off - Season Systems to Fossil Fuels

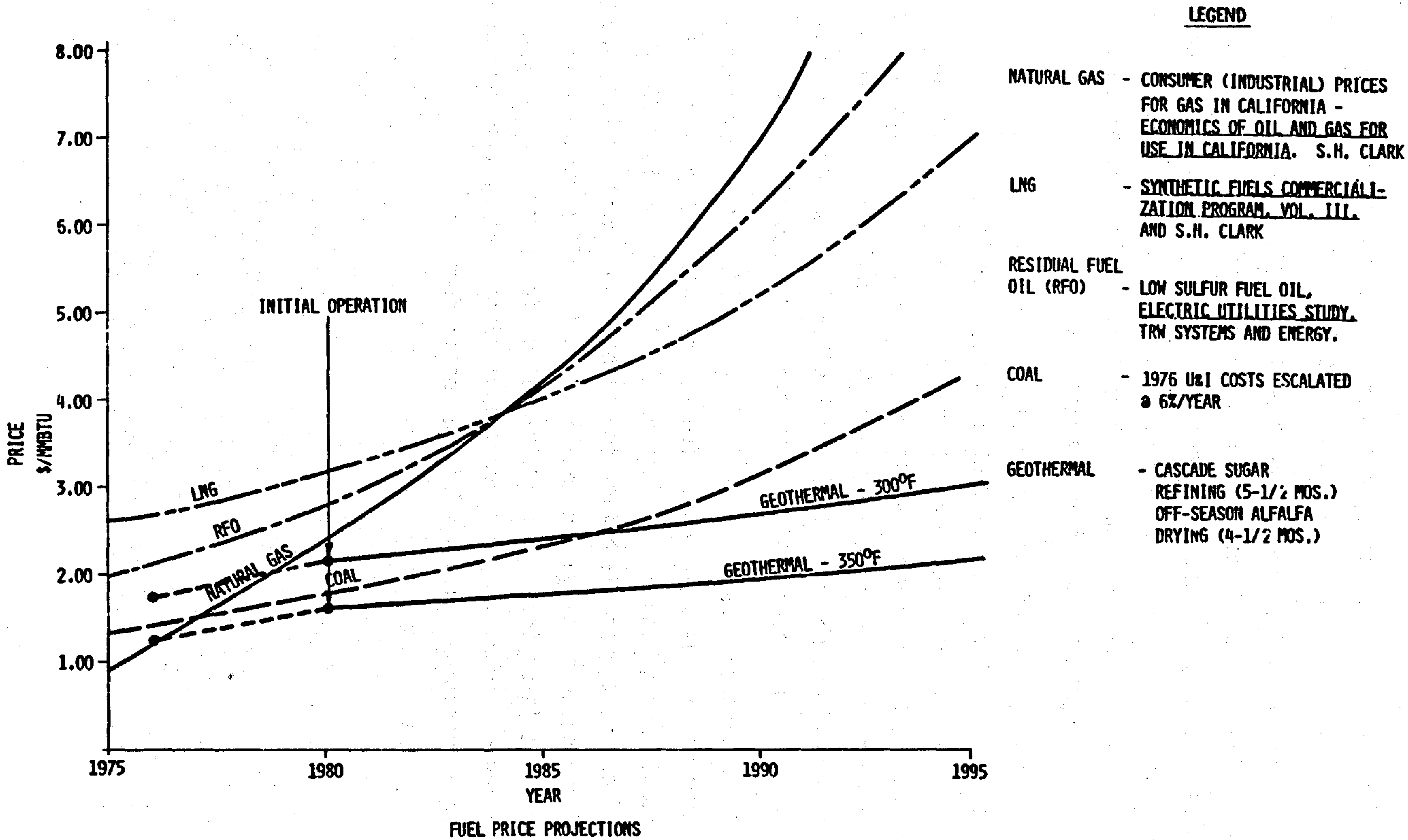


Figure 6-4 - Fuel Price Projection Comparisons of 300°F and 350°F Cascaded/Off-Season Systems to Fossil Fuels

Projected cost data for the four geothermal systems and each of the fossil fuels are shown in five year increments in Table 6-1.

Figure 6-2 shows the differences in cost between a 300°F and a 350°F geothermal system, both of which incorporate cascading heat from the boiler to beet pulp dryer for 5-1/2 months, the length of the sugar campaign. As can be seen from this figure, a 300°F cascading system would not be economically competitive with fossil fuels until after 1985, while a 350°F cascading system would be competitive shortly after initial operation.

The difference in projected costs between a cascaded and a cascaded/off-season system for 300°F geothermal fluids is shown in Figure 6-3. A cascaded/off-season system applies to a cascaded one that is used for sugar refining for 5-1/2 months and for off-season use, such as alfalfa drying, for 4-1/2 months. From this figure it can be seen that although a 300°F cascaded geothermal system would not be economical until after 1985, a 300°F cascaded/off-season system would be economical from initial operation of the system.

Figure 6-4 compares the costs of the 300°F and 350°F cascaded/off-season geothermal systems to the costs of fossil fuels. As this figure indicates, the most economical combination of the geothermal alternatives is a 350°F system that cascades heat from the boiler to the beet pulp dryer during the 5-1/2 months of the sugar campaign and that is used for off-seasonal uses, such as onion or alfalfa drying for an additional 4-1/2 months. This type of system not only appears to be the most economical geothermal system, but also appears to be more economical than any of the fossil fuels.

TABLE 6-1 - FOSSIL FUEL AND GEOTHERMAL PRICE PROJECTIONS

($/MMBtu)

YEAR	FUEL TYPE: NATURAL GAS	RESIDUAL FUEL OIL	COAL	LIQUEFIED NATURAL GAS	GEOTHERMAL CASCADED - 300°F	GEOTHERMAL CASCADED- 350°F	GEOTHERMAL CASCADED/OFF SEASON 300°F	GEOTHERMAL CASCADED/OFF SEASON 350°F
1976	1.42	2.10	1.38	2.70	3.10	2.22	1.73	1.27
1980	2.44	2.89	1.74	3.20	3.91	2.80	2.18	1.60
1985	4.25	4.21	2.33	4.00	4.32	3.09	2.41	1.77
1990	7.05	6.19	3.12	5.25	4.77	3.42	2.66	1.95
1995	11.82	9.09	4.17	7.00	5.26	3.77	2.94	2.16

The LNG curve shown in Figure 6-1 has been derived from two sources. The 1976 point on the curve is based on a formula developed by Stanford Research Institute for the Synthetic Fuels Commercialization Program (Reference 6-3). The latter part of the curve is based on price projections for LNG estimated by S. H. Clark (ref 6-1).

6.0 REFERENCES

6-1 S. H. Clark, California Energy - The Economic Factors - Invited Papers on California's Future Energy Sources, "Economics of Oil and Gas for Use in California", 1976.

6-2 Electric Utilities Study, An Assessment of New Technologies from a Utility Viewpoint, TRW Systems and Energy, November, 1976.

6-3 Recommendations for a Synthetic Fuels Commercialization Program, by Synfuels Interagency Task Force to the President's Energy Resources Council, June, 1975.

7.0 ENVIRONMENTAL IMPACT ASSESSMENT

Application of geothermal heat to the sugar refining process will result in environmental impacts. This section assesses the major potential impacts associated with the design alternates for use in sugar refining processes at the previously identified resource areas. Only major impacts are discussed and include the following:

- subsidence
- seismicity
- atmospheric impacts
- hydrological impacts
- noise
- erosion and landslides
- aesthetics

Several design alternates were presented in Section 3. In addition, six geothermal resource areas have been identified for their potential application to the sugar refining process, as described in Section 2. Figure 7-1 shows the geographical location of each of these areas have been identified as:

- <u>Southern California</u>: Salton Sea, Heber, Brawley and East Mesa.
- <u>Northern California</u>: Geysers, Calistoga, Wilbur Hot Springs and Morgan Springs.
- <u>Southwest Idaho</u>: Crane Creek, Weiser, Vale Hot Springs, Mountain Home, Bruneau-Grandview.
- <u>Southeast Idaho</u>: Raft River, Brigham City
- <u>Arizona</u>: Chandler
- <u>Washington</u>: Longmire Hot Springs, Sumit Creek.

Some detailed environmental assessments and studies have been performed on the specified geographical areas. For the interest of the reader, several of these studies are cited in the beginning of the reference section, references 7-1 through 7-11.

The final selection of a geothermal system will be influenced in part by the environmental impacts as well as by the technical and economic feasibility associated with each design alternate. This section evaluates the environmental impacts of the design alternates with respect to the resource areas in order to facilitate the selection of the design alternate with the least potential impact. In addition, this section also includes a brief comparison of the advantages and disadvantages of a fossil fuel system versus a geothermal system.

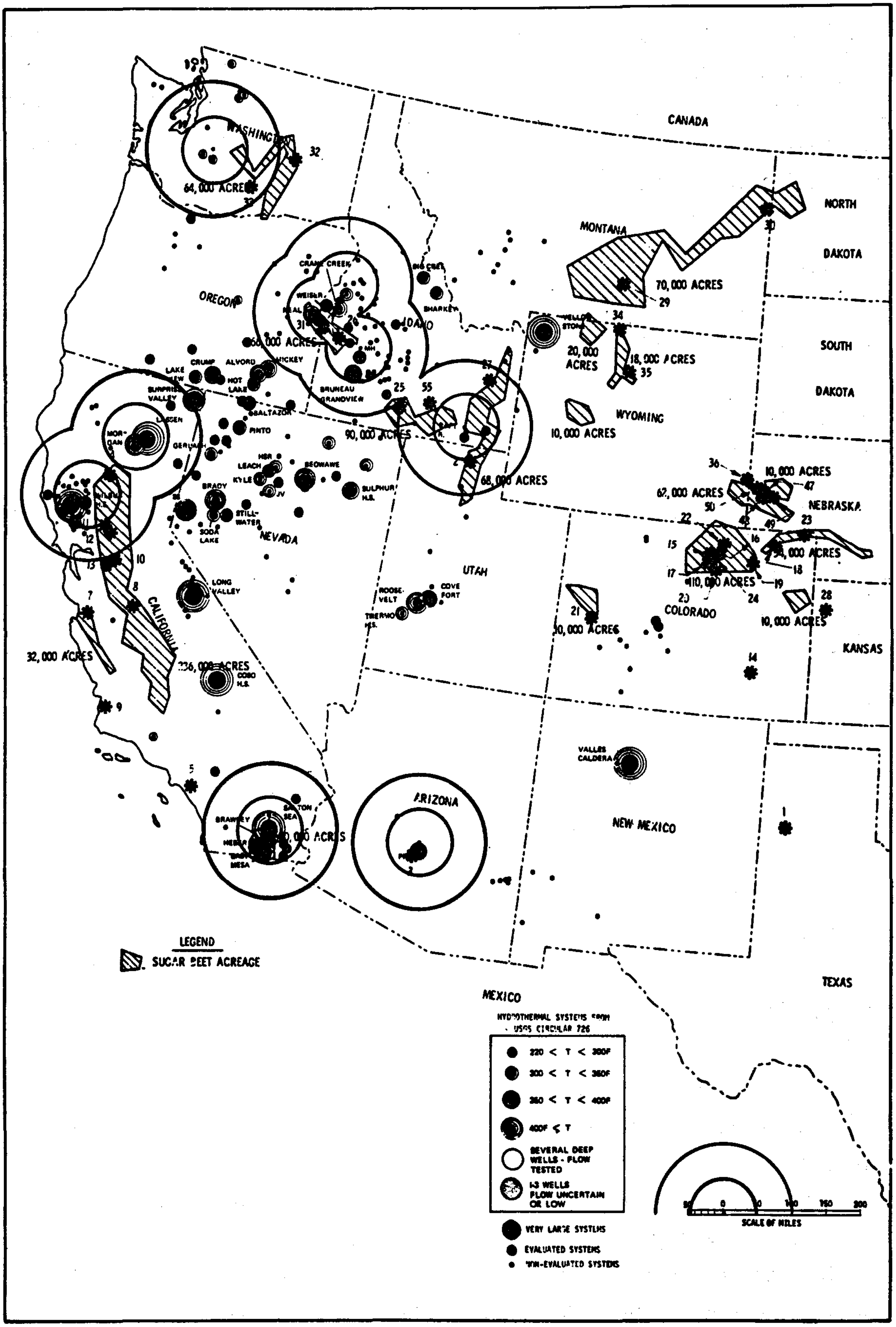


Figure 7-1 Geothermal Resource Areas and Sugar Beet Producing Areas.

7.1 Subsidence

Withdrawal of large volumes of geothermal fluids over long periods of time can result in subsidence of the ground surface. When fluids are removed from a groundwater aquifer, in which withdrawals exceed recharge, the pressure of the reservoir decreases, which can cause land subsidence.

In general, subsidence results from the combination of (1) the compressibility of the reservoir, (2) the reduction of pressure in the reservoir, and (3) the thickness of the producing formation. As the fluid pressure decreases, stresses are increased followed by compaction of the compressible beds of the aquifer. The magnitude of the subsidence also depends on the time the increased pressure has been applied and the past history of stress. Generally, subsidence is irreversible.

In a dry-steam field, like The Geysers, subsidence is not likely to occur since the reservoir rocks and not the steam, bear the overburden weight. However, in a hot water field like the Imperial Valley, the water provides support for the overburden. In such areas, reducing aquifer pressures could cause subsidence.

Subsidence has previously been associated with the pumping of fresh groundwater, the exploitation of oil and gas reservoirs and the withdrawal of geothermal fluids from Wairakei, New Zealand and Cerro Prieto, Mexico. At Cerro Prieto, subsidence of up to 7 inches has been measured 7 miles outside of the well (ref. 7-1). Subsidence can be prevented or minimized by maintaining fluid levels with reinjection.

In the application of geothermal resources to the processing of sugar beets, there are four well flow/effluent handling alternatives which may influence subsidence. These four alternatives are shown in Figure 7-2. In Alternate HE-1A (With Reinjection), the geothermal fluid is passed through a heat exchanger and returned to the ground via a reinjection well. Since the cycle is closed and the fluid is not diminished, no subsidence is expected to occur. However, if the fluid was injected into a porous aquifer or one that is faulted, the fluid could move into nearby zones, thereby decreasing reservoir pressure and causing some subsidence. In Alternates HE-1B (Without

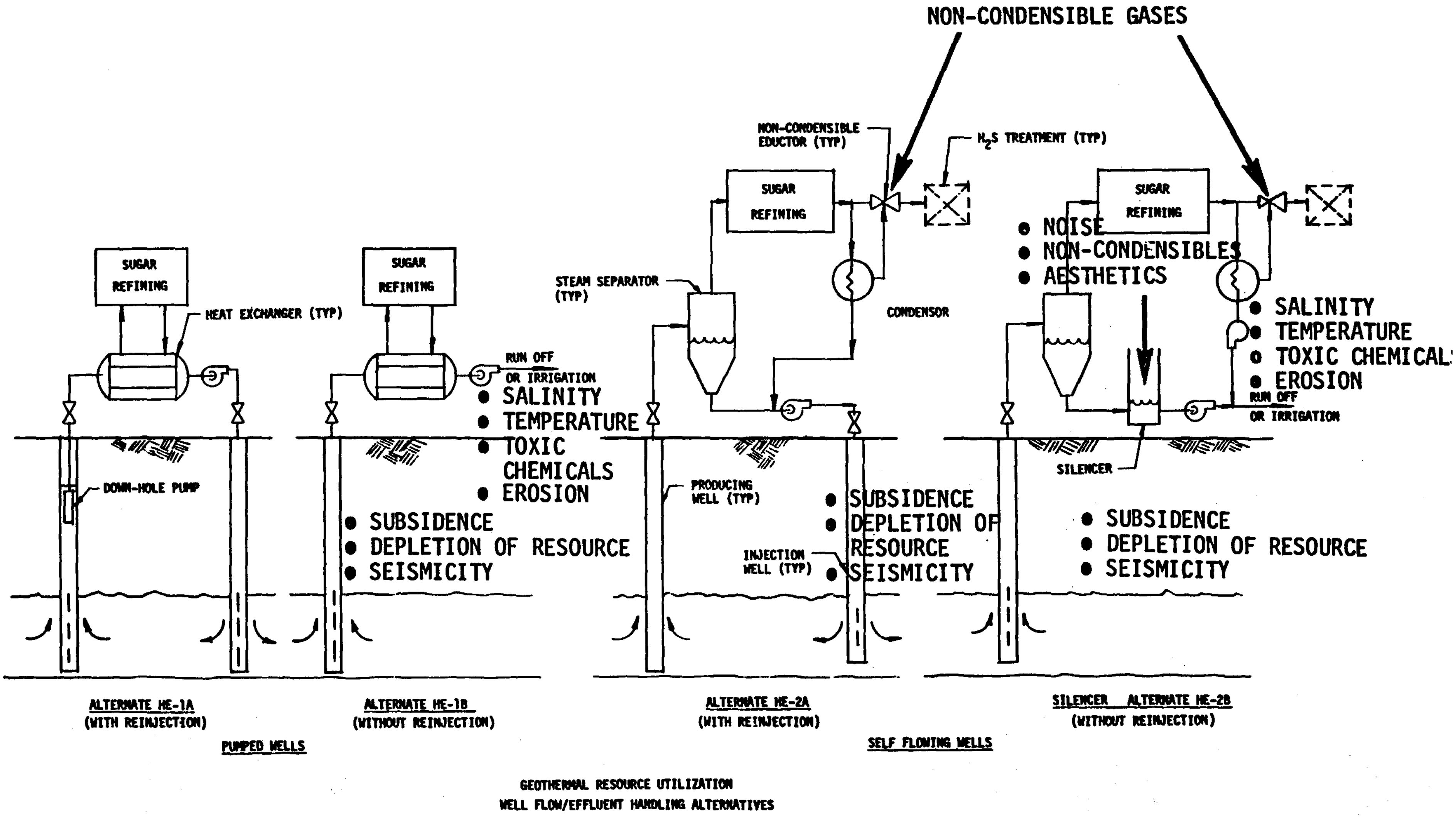


Figure 7-2 Geothermal Well Flow/Effluent Alternatives

Reinjection) and HE-2B (Without Reinjection), no reinjection is planned and all fluid is to be used for surface purposes (surface purposes include irrigation, runoff, space heating, desalinization, etc., and are discussed under Hydrological Impacts, Section 7.4). Both Alternates HE-1B and HE-2B may result in substantial subsidence, as well as depletion of the resource. Although Alternate HE-2A (With Reinjection) is designed for reinjection, subsidence still may occur, since some of the fluid is lost in the sugar refining process. Therefore, to maintain reservoir pressure and minimize subsidence, make up or additional water must be reinjected into the reservoir along with the unconsumed geothermal fluid. Because of the nature of the sugar refining process, this make up water can be supplied from the process waste water. Reinjection can maintain reservoir pressure and maximize reservoir life.

Of the six geographical areas studied for potential application of geothermal resources to the sugar refining process, two areas, the Imperial Valley and central Washington, pose special problems with respect to subsidence. Land use in the Imperial Valley is primarily agricultural. Due to the arid climate, an extensive irrigation system has been designed and constructed, so that tile canals and drains slope approximately 5 feet/mile (ref. 7-12). In addition, the deltaic sediments of the Imperial Valley are relatively unconsolidated and imcompetent, and are dependent upon the pore pressure of the water for support. It has been estimated that the Imperial Valley already subsides naturally at a rate of 1 foot per century, which is probably due to its naturally occurring tectonic activity. Therefore, subsidence could seriously affect the ability of the irrigation system to function.

In central Washington, subsidence may result from the development of geothermal resources. State law prohibits the injection of liquid wastes, except under extenuating circumstances. Generally, liquid wastes are treated as point sources subject to the National Pollutant Discharge Elimination System (NPDES) stipulated by federal regulations. To date, there have been no test cases pertaining to injection of geothermal fluids. State officials feel that it is possible that this type of injection might be interpreted as an extenuating circumstance; however, regulations will have to be promulgated which apply specifically to geothermal resources (ref. 7-13).

7.2 Seismicity

Changes in reservoir pressure may result in instabilities that increase seismic activity. Such instabilities, caused by pressure reduction from the production of fluids or pressure increases due to injection, have occurred in the Wilmington Oil Field, California, the Baldwin Hills Oil Field, California and Rangely Oil Field, Colorado. Also, seismic activity has been associated with wastewater injection at the Rocky Mountain Arsenal in Colorado. These earthquakes have not been damaging. Magnitudes have generally been below 4.5 on the Richter Scale, which is considered minor.

It has been stated that seismic triggering is associated with an increase in fluid pore pressure in rocks. In dry-steam fields, earthquakes should not be triggered since withdrawal of the geothermal steam reduces pore pressure. In a hot-water field, water removal has the same effect; however, seismicity may be increased by the redistribution of fluid pressure. Since geothermal areas are linked to areas of seismic activity, it is possible that the associated faulting system may be a route for the fluids to redistribute and recirculate within the aquifer. Thus, to minimize subsidence and seismic activity, geothermal brines should be reinjected at pressures lower than those known to trigger earthquakes. Reinjection at lower pressures should help relieve stresses gradually (ref. 7-14).

Figure 7-3 shows the tectonic features of the Western United States in relation to those areas of sugar beet production and geothermal resources. As can be seen, the Imperial Valley is an area that is seismically active. The Valley is traversed by several major faults and has experienced many earthquakes. In 1975 and 1976, the Brawley area experienced a swarm of minor earthquakes, sometimes as many as 1 or 2 per hour, and it should be recognized that geothermal activities could increase this natural process.

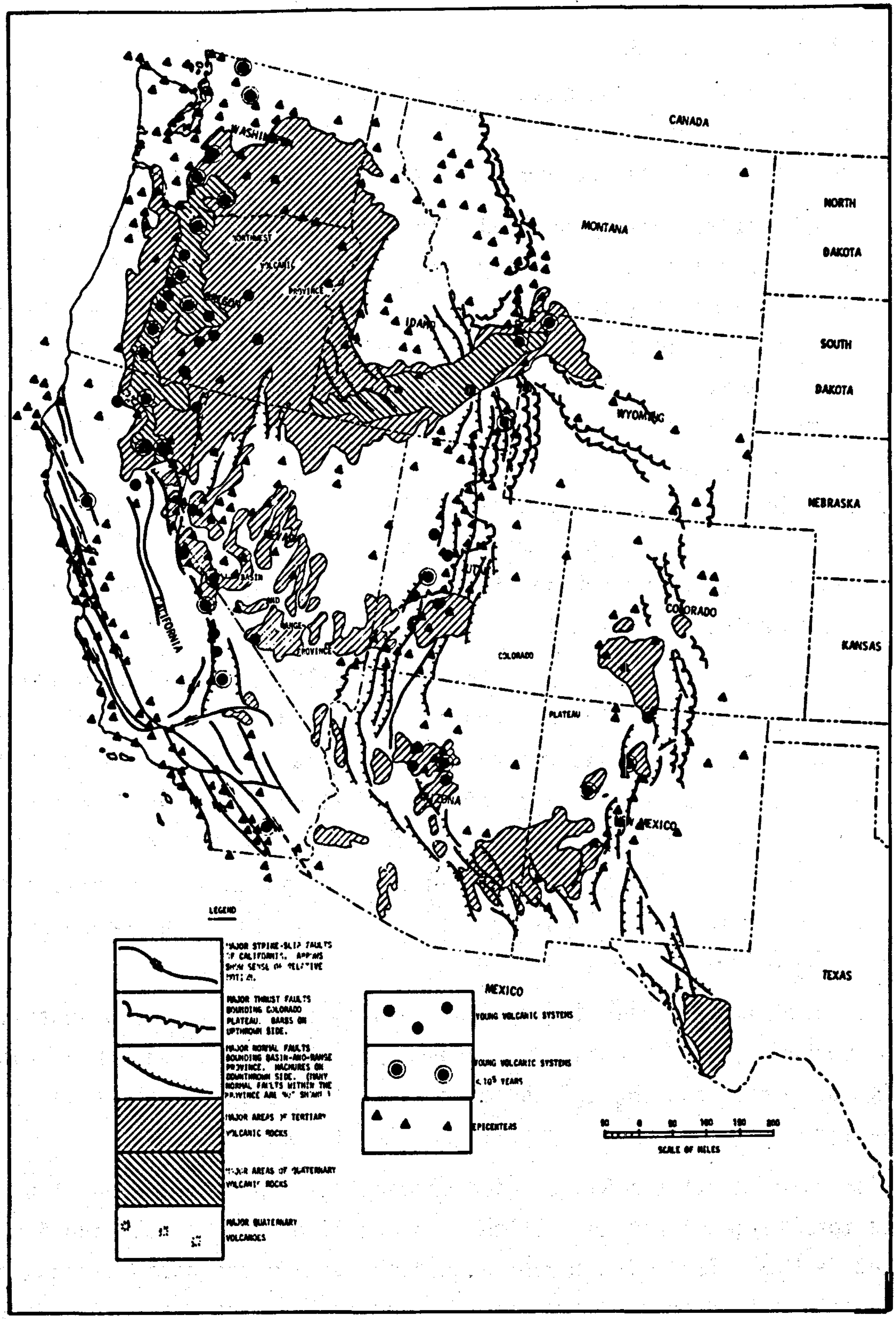


Figure 7-3 Tectonic Features of the Western United States. [Sources: King, Smith & Shaw, Coffman & Hake]

7.3 Atmospheric Impacts

Air pollution will increase as a result of geothermal development. Emissions produced during the exploration, testing and construction phases are different from those produced during the operation phase.

Atmospheric impacts associated with field development result from construction of roads, clearing the site, movement of heavy equipment onto the site, operation of gasoline and/or diesel-powered vehicles and equipment, and construction of facilities and pipelines, etc. In general, emissions produced by field development will primarily be particulate matter, contributed to the atmosphere by wind erosion following removal of the area's vegetative cover. The amount of pollutants emitted from internal combustion engines is expected to be minimal in comparison to pollution currently emitted in most of the six areas. Local degradation of air quality may occur during field development; however, the overall effect is expected to be small.

Development and operation of the well itself also results in atmospheric impacts. Geothermal liquids and steam usually contain substantial amounts of non-condensible gases and vapors, which are released when there is a loss of fluid pressure or condensation of steam. These gases and vapors usually amount to less than 3 percent of the total steam fraction, although the amount can vary. It has been estimated that the steam at the world's five largest geothermal power plants contains from 0.15 to 30% non-condensible gases (ref. 7-15).

Non-condensible gases include carbon dioxide, (CO_2), hydrogen sulfide (H_2S), methane (CH_4),ammonia (NH_3) hydrogen (H_2) and nitrogen (N_2). Vapors consist of boric acid (H_3BO_3) and mercury (Hg). Table 7-1 shows the fraction of the total gas content of typical geothermal steam.

For example, at the Geysers non-condensible gases form about 1 percent of the total steam fraction. Of this, about 80 percent is CO_2 and 4.5 percent is H_2S. Table 7-2 shows the content of various gases associated with geothermal steam production at The Geysers. Emissions at The Geysers

TABLE 7-1 FRACTIONS OF TOTAL GAS CONTENT (ref. 7-15)

CONSTITUENT	PERCENT
CO_2	78.0 - 95.0
H_2S	1.0 - 17.0
H_2	1.0 - 13.0
CH_4	0.0 - 12.0
N_2	0.2 - 9.0
NH_3	0.0 - 1.7
ARGON, ETHANE H_3BO_3, HCl, HF, SO_2	TRACE AMOUNTS

TABLE 7-2 GASES ASSOCIATED WITH GEOTHERMAL STEAM AT THE GEYSERS IN VOLUME PERCENT (ref. 7-1)

CONSTITUENT	VOLUME PERCENT
H_2O	98.045
CO_2	1.242
H_2	0.287
CH_4	0.299
N_2	0.069
H_2S	0.033
NH_3	0.025
P_3PO_4	0.018

result from the well during bleeding and venting, from gas ejector vents on the condensers, and from the cooling towers. About 20-30 percent of the non-condensibles is reinjected with the condensate and the remainder is released to the atmosphere.

The primary gaseous emission problem at The Geysers and at other geothermal developments has been H_2S. The human level of toxicity for H_2S is 20 ppm, which has been exceeded at geothermal fields. In addition, the odor of H_2S, which is that of rotten eggs, is detectable at .025 ppm.

H_2S abatement systems include sulfur recovery systems such as a Claus Plant or Stretford unit. A benefit of utilizing a sulfur recovery system is that the recovered elemental sulfur can be sold, which helps to offset the expenditures of installing the abatement system. Pacific Gas and Electric (PG&E), who operates the power plants at the Geysers, plans to install the Stretford Unit on all future plants to reduce H_2S emissions. PG&E expects H_2S emissions to be reduced by 90% with this abatement system and to meet California air quality standards.

Application of geothermal heat to the sugar refining process will result in increased atmospheric impacts during the field development phase, as well as the operational phase, although most of these impacts are expected to be minor. During the field development phase, there are several possible alternatives which could be implemented. These alternatives, shown in Figure 7-4 and 7-5, include directional drilling, vertical drilling, adjacent wellheads and remote wellheads. As shown in Figure 7-4, a well that is directionally drilled will result in fewer surface impacts since the production and injection wellheads can be placed close enough to the process fluid heat exchanger so that no pipeline is needed to bring the fluid to the exchanger. Vertically drilled wells will require a pipline system to transport the geothermal fluid to and from the heat exchanger and to the injection wellhead. A system that uses pipelines to transport geothermal fluids will increase particulate (dust) emissions and pollutants emitted from internal combustion engines as a direct result of surface erosion and increased vehicle usage; however, effects should be localized and temporary.

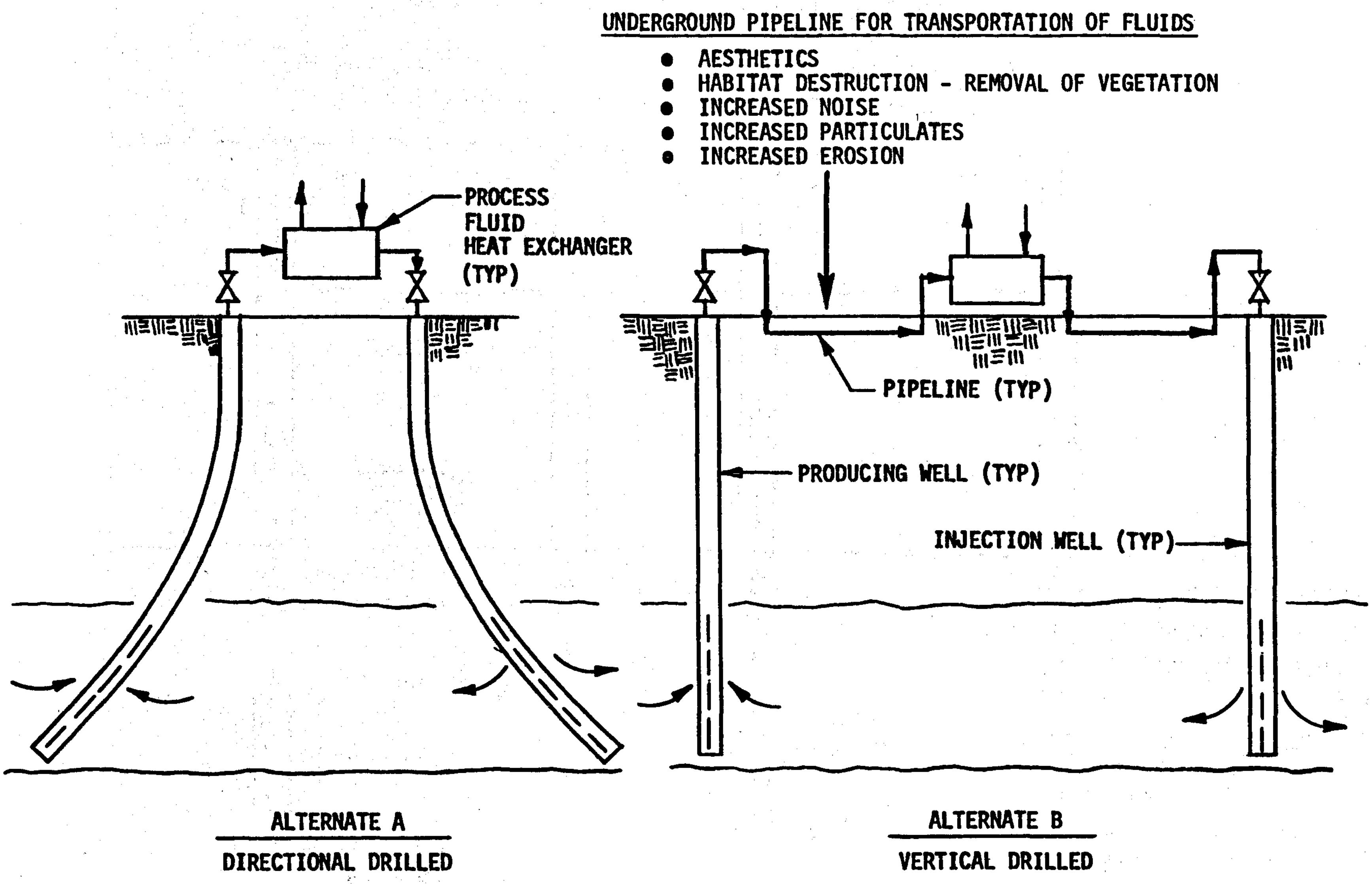


Figure 7-4 Well Configuration Alternatives

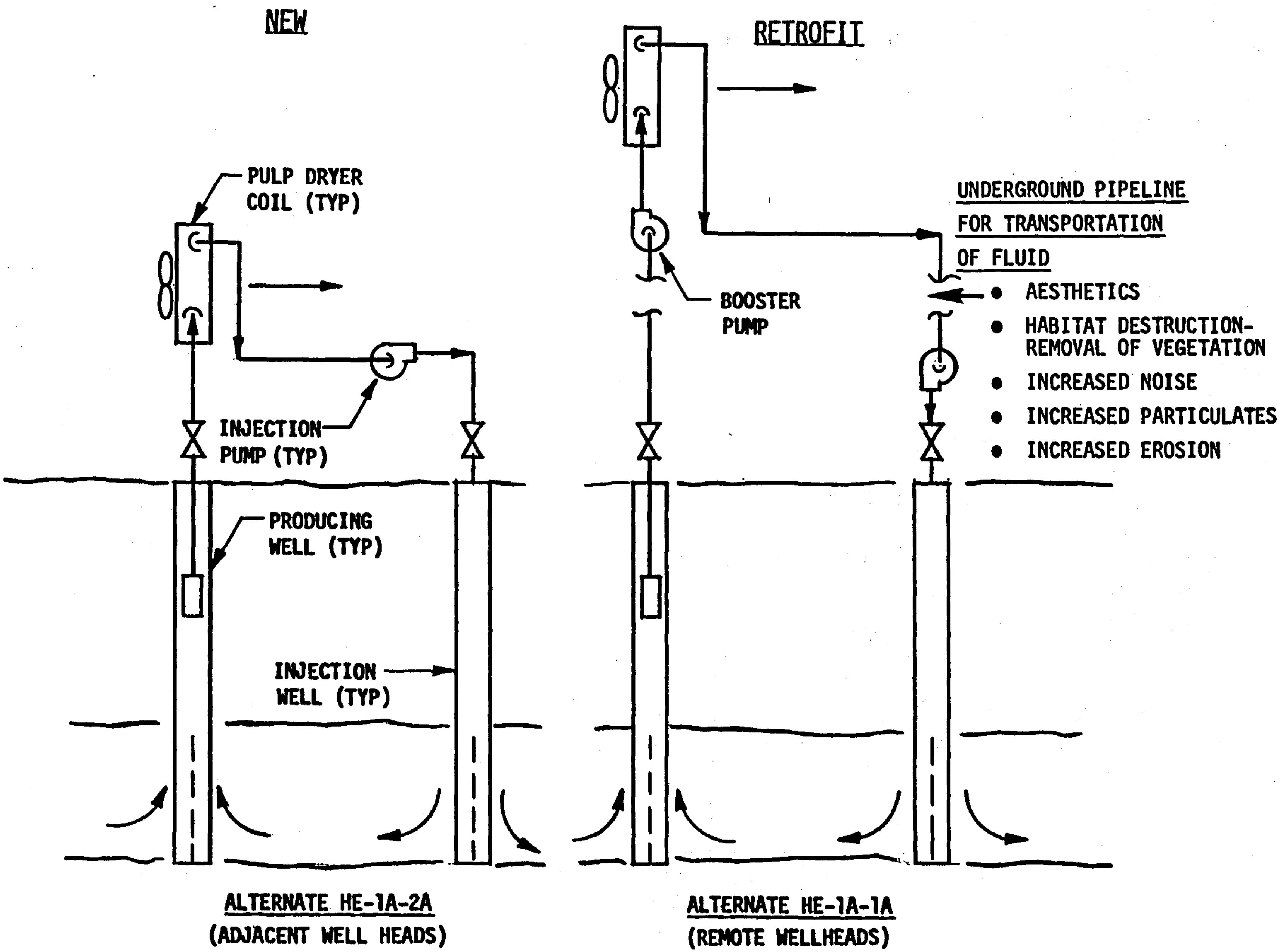


Figure 7-5 Pulp Dryer Utilization Alternatives

It has been established in recent TRW studies, for ERDA and the Bureau of Reclamation, that directionally drilled wells, with horizontal throws up to one mile, are economically competitive with vertical wells and buried insultated overland piping.

Placement of the wellhead may also result in similar atmospheric impacts. Figure 7-5 shows two alternatives, adjacent wellheads and remote wellheads, that can be applied to the refining process. An underground pipeline will probably have to be constructed for systems where the well-head is located remotely to the process for aesthetic reasons. Thus, impacts will be greater for the remote wellhead system than for the adjacent wellhead system since more surface area will be disturbed.

Atmospheric impacts from the operational phase will primarily be an increase in the emissions of non-condensible gases in connection with the refining process itself. Figure 7-2 shows four alternatives for well flow/ effluent handling. Because the geothermal fluid is fully contained in a closed system, no emissions are expected. In a flashed system with rein-jection, Alternate HE-2A, non-condensible gases are emitted during the process, which can be treated in an abatement system. If the geothermal fluid is not reinjected, as in Alternate HE-2B, non-condensible gases are emitted during condensation of the geothermal fluid and from the silencer when the fluid is brought to atmospheric pressure. In the first instance, the gases can be treated similarly to the previously discussed alternate (Alternate HE-2A). Gases from the silencer will also probably be treated.

7.4 Hydrological Impacts

In this section, the hydrological impacts resulting from applying geothermal fluids to the sugar refining process are discussed and include impacts to both surface and groundwater quantity and quality. Similar to atmospheric impacts, the impacts to the hydrological cycle vary with each phase of development.

7.4.1 Quantity - Utilizing geothermal fluids for sugar processing may affect groundwater and surface water supplies. The extent to which supplies will be affected will depend on the exact design of the system, the geology of the area, the integrity of the well casings and the ultimate disposal of the fluids, etc.

The groundwater regime may be altered if adequate protection and control measures are not taken during development of the field. For example, if a geothermal reservoir is overlain by a productive freshwater aquifer it is possible that the fresh water aquifer can be contaminated if drilling through the various horizons causes the geothermal fluids to mix with the freshwater fluids. If the different horizons are not kept separate from each other by proper cementing of the casing in either the production or reinjection well, it is possible that the freshwater aquifer could be contaminated, especially if the geothermal fluid is highly saline or mineralized.

Also, spills and blowouts could have a negative effect on surface water supplies. For example, if hypersaline waters were accidentally discharged into a freshwater course, the ultimate use of the freshwater course could be altered since the water might be too saline for use.

In many regions, groundwater is a supplementary supply to surface waters. If the resource were contaminated, the overall available quantity of water useable for purposes such as drinking or irrigation, could be adversely affected. This is also true for surface water supplies which could potentially be polluted. Much of the Southwest's water supply is already allocated by treaty or law. Changes to this established system could have far reaching effects to economies such as agriculture, that rely on a dependable water supply.

7.4.2 <u>Quality</u>- Geothermal fluids often contain significant quantities of dissolved solids including sodium, calcium, potassium, magnesium, and chloride. In addition, the fluids often have significant concentrations of heavy metals, such as iron, manganese, copper, lead, mercury, zinc and strontium. The total dissolved solid (TDS) content of geothermal fluids can range from 200 milligrams per liter (mg/l) to over 250,000 mg/l. Water with a TDS content less than 1500 mg/l is generally considered potable. The Imperial Valley geothermal fluids are highly saline with TDS concentrations ranging from 2000 mg/l to over 250,000 mg/l (at the Salton Sea). However, the fluid in Southwest Idaho (at Mountain Home) is considered to be potable with TDS concentrations about 800 mg/l. Major potential hydrological impacts include increased siltation and sedimentation of surface water from road construction and drilling site excavation, contamination of surface waters from spills or blowouts, accidental contamination of freshwater aquifers from improper casing, and degradation of the resource.

In areas where the quality of the brine is low, reinjection of the brine is usually a convenient means of disposal. It should be noted that disposal by evaporation means that a liquid waste disposal problem would be traded for a solid waste disposal problem. To evaporate 126 million gallons of geotnermal brines at a rate of 6 feet/year, a 65 acre evaporation pond would be required. This is roughly equivalent to the amount of brine produced from a well flowing at 1000 g.p.m. operating for 5.5 hours per day (ref. 7-1). Residual solid waste would then be disposed of in an approved disposal site. Even if evaporation were used as a means of disposal, contamination of the ground water resources would be possible if the brines leached into the soil. The Bureau of Reclamation has used a plastic lined holding pond to allow waste waters to evaporate without infiltrating into the soil.

7.5 Noise

Noise generated from geothermal development has been a problem since the first steam wells were completed. Noise from geothermal development, which is similar to that from other industrial operations, varies in intensity, duration, and frequency with the various phases (i.e., drilling, testing, and full operation). In general, noise levels decrease with distance and vary with humidity, vegetation type, topography, wind direction, etc. Geothermal operations which generate noise include:

- Site clearing
- Road and facility construction
- Well drilling
- Well venting and bleeding

In addition, it is possible that loud noise could be generated if steam lines or wells should break or rupture. Noise will be generated, no matter which well or wellhead configuration shown in Figures 7-4 and 7-5 are utilized. Of the four well flow/effluent handling alternatives shown in Figure 7-2, it is the flashed system without reinjection, Alternate HE-2B, that will generate the most noise as the water is brought down to atmospheric pressure prior to release as runoff. It should be noted that a silencer will be used to reduce noise to acceptable levels; however, the noise will still be continuous.

Table 7-3 presents a comparison of noise levels generated at the Geysers and from other sources. Few noise measurements from geothermal fields other than the Geysers have been made. As Table 7-3 shows, noise levels associated with geothermal development can be excessive and can pose significant environmental impacts. For example, the noise from air drilling rivals that generated from the takeoff of a jet aircraft and the threshold of pain. Noise levels that are excessive can pose a health and safety hazard to employees, can be objectional to residents or people visiting the area and can disrupt wildlife distribution and patterns. Table 7-4 presents the results of noise tests on various types of animals, including swine, cows and poultry. It should be noted that although

TABLE 7-3 COMPARISON OF NOISE LEVELS BETWEEN GEOTHERMAL AND OTHER SOURCES

(refs. 7-14, 7-16, 7-17)

NOISE SOURCE	LEVEL (dBA)	DISTANCE (ft)
THE GEYSERS		
DRILLING OPERATION (AIR)	126	25
DRILLING OPERATION (AIR)	55	1500
MUFFLED TESTING WELL	100	25
MUFFLED TESTING WELL	65	1500
STEAM LINE VENT	100	50
STEAM LINE VENT	90	250
COMPARATIVE LEVELS		
JET AIRCRAFT TAKEOFF	125	200
THRESHOLD OF PAIN	120	AVERAGE
DRILLING RIG (AIR)	102	50
UNMUFFLED DIESEL TRUCK	100	50
LOUD MOTORCYCLE	95	50
ROAD BUILDING EQUIPMENT	80 - 90	50
USAF RECOMMENDED MAXIMUM	85	--
STREET CORNER IN A LARGE CITY	75	AVERAGE
NORMAL SPEECH	65	1
STEAM EXITING BLOOIE WITH MUFFLER	60	50
STEAM WELL VENTING-STANDBY	60	(AT SOURCE)
ACCOUNTING OFFICE	60	--
RESIDENTIAL AREA AT NIGHT	40	AVERAGE
BROADCASTING STUDIO	25	--
THRESHOLD OF HEARING	0	--

* DECIBEL A SCALE: A DECIBEL IS THE UNIT FOR MEASURING SOUND INTENSITY. ONE DECIBEL CHANGE IN SOUND IS THE SMALLEST DIFFERENCE IN SOUND INTENSITY THAT THE HUMAN EAR CAN DETECT.

noise levels can be excessive, most of the noise is temporary. However, if a steam field or a flashed system without reinjection is utilized, than a certain amount of noise will be generated permanently. Noise can be controlled by use of mufflers.

In all six resource areas, the noise generated from geothermal operations is expected to have a minor effect upon the surrounding areas; however, in northern California, Washington and southeast Idaho, the impacts could be more severe. For example, the Geysers development has produced noise of sufficient loudness to have caused complaints to be made to the various development companies, the Pacific Gas and Electric Co., the Lake County Air Pollution Control District and the California State Office of Noise Control.

At The Geysers, unmuffled sound pressure levels of over 130 dBA have been measured at a distance of 100 feet from well outlets. Under the right conditions, this sound can be heard for miles. Generally, absorption of sound at all frequencies tends to increase with increasing air temperature and decreasing moisture content. In studies on the noise emitted from The Geysers operations, it was found that the ambient noise level that exists when the wells are not venting is very low (in the vicinity of 28-35 dBA). The noise emitted when the well is being vented is low frequency and audible at great distances. During the winter when strong temperature inversions and higher relative humidities occur, the problem is compounded, since the sound waves are bent downwards. The steep terrain of the Geysers area can contribute to a reduction in the noise levels due to the tendency of the ridges to diffract the sound waves. It should be recognized that because The Geysers area is primarily devoted to geothermal development, with a low background noise level, the people living near the development are very likely to complain about the noise (ref. 7-18).

If the geothermal field at Longmire Hot Springs, Washington were to be approved for development, it is unlikely that excessive noise would be tolerated, since Longmire Hot Springs is situated in a National Park. Even if the resource were developed adjacent to the National Park, excessive noise levels would probably not be tolerated.

TABLE 7-4 EFFECTS OF NOISE ON ANIMAL POPULATIONS (ref. 7-17)

ANIMAL	TRIALS	SOUND SIMULATION	EFFECT
SWINE	5	120 - 130 dB; AIRCRAFT CONTROL AT 70 dB AIRCRAFT	NO INJURY TO GROSS ANATOMY OF ORGAN OF CORTI
	MULTIPLE 15-SECOND EXPOSURE, 4, 8 OR MORE TIMES	130 dB AT 300 - 600 Hz	INCREASE IN HEART RATE
	UNSPECIFIED	100 - 120 dB AT 200 - 5000 Hz	SOWS: NONE; PIGLETS: HUDDLING, SQUEALING
	DAILY 6 A. M. - 6 P.M.	120 - 135 dB	NO IMPACT ON MATING; HEAVIER PIGLETS AT BIRTH; MODIFIED WEANING
	SEVERAL DAYS	93 dB	CASTRATED MALES: ALDO STERONISM AND WATER AND SODIUM RETENTION
MILK COWS	PASTURED NEAR AIR FORCE BASES	UNSPECIFIED	NO MILK PRODUCTION; DIFFERENCES AMOUNG COWS AT VARYING DISTANCES FROM FIELD
	PAPER BAG EXPLOSIONS - 2 MINUTE FREQUENCY DURING MILKING	UNSPECIFIED	NO MILK GIVEN DURING EXPLOSIONS; 70% AFTER 30 MINUTES
POULTRY	EGG INCUBATION WITH SOUND, 8 IN 20 MINUTES, 8 A.M. DAILY AND 8 P.M. - 8 A.M. EVERY 3rd NIGHT	AIRCRAFT NOISE 120 dB	NONE
	BROODING HENS SUBJECTED TO SOUND	UNSPECIFIED	8 OF 9 HENS QUIT BROODING; ONLY 1 OF 12 EGGS HATCHED BY REMAINING HEN
	CHICKS UNDER NOISE FROM 8 A.M. - 8 P.M. DAILY AND 8 P.M. - 8 A.M. EVERY 3rd NIGHT.	AIRCRAFT NOISE 80 - 115 dB AT 300 - 600 Hz	NONE
MINK	SERIES OF SONIC BOOMS	485 Hz 2.0 lb/ft^2 - 0.5 lb/ft^2 GRADIENT	INCREASED LITTER SIZE
	6 SONIC BOOMS IN 10 DAYS	UNSPECIFIED	NONE

The two resource areas considered in the southeast Idaho area are Raft River in Idaho and Brigham City in Utah. The Raft River is relatively uninhabited and ambient noise levels are low. The Raft River geothermal area is known to be a nesting site for the Peregrine falcon and the ferriginous hawk. Both are considered rare or endangered species. The noise that would be generated from geothermal development in this area, especially that generated from drilling, may have a negative impact on these species.

The site near Brigham City is located a number of miles outside of the city in a predominantly agricultural area, with low levels of ambient noise. Some rare or endangered species have been seen near the geothermal site, including the humpback club, Colorado River Squawfish, Woundfin, Peregrine falcon, black footed ferret and the Utah prairie dog. Excessive noise from geothermal operations may have deleterious impacts on these species.

7.6 Erosion And Landslides

Development of geothermal resources in areas of steep terrain and unstable soils may result in both landslides and excessive soil erosion. In areas where there is steep terrain, excavation of the land is required during construction to provide room for drilling sites, roads, facilities, pipelines, etc. The amount of soil erosion tends to increase when natural slopes are cut and filled since slopes are made more steep and the vegetative cover is removed. As a result of the loss of vegetation cover, the soil is no longer protected from the impacts of precipitation. This leads to an increase in stream siltation and the suspended sediment load, as well as to an increase in wind erosion and potential flash floods. When construction is completed and the slope is rehabilitated with new vegetation, sediment, siltation and other erosional problems are usually reduced. However, it should be noted that there will always be an increase in soil erosion from surface disturbances.

It has been estimated that for areas like The Geysers, where the terrain is steep, approximately 1 to 3 acres of cut and fill land is needed to provide enough room for drilling operations. The amount of land disturbed by access roads and pipelines is shown in the following table (ref. 7-1):

TYPE OF EXCAVATION	WIDTH OF EXCAVATION
Primary Roads	50 Feet
Secondary Roads	30 Feet
Pipelines	40 Feet

Landslides, known to occur as a result of geothermal development, can be a serious problem on steep slopes underlain by weak bedrock. For example, the California Division of Mines and Geology has estimated that at the Geysers, approximately 50 percent of all facilities are situated on unstable slopes. Although some soils in The Geysers area is stable (Los Gatos and Maymen), much of the soil is the Yorkville series, considered to be highly unstable and to have poor slope stability. In fact, portions of the bedrock have been weakened by faulting, fracturing and alteration from the geothermal resource. In 1973, the Happy Jack Well No. 7 was broken at a depth of 35 feet following heavy rains and presumably a small landslide. The well is still uncontrolled. Excavation of new sites and facilities may trigger movement of slope material, even if sound engineering practices are used.

Topographic descriptions of the six resource areas are listed in Table 7-5. With the exception of northern California and Washington, which are located in mountainous areas with steep slopes, the resource areas are located on either flat desert or valley lands. Thus, it appears that erosional problems will be more severe in the Northern California and Washington areas where the geothermal fields are located beneath steep slopes.

Generally, in the application of geothermal heat to sugar beet processing, all proposed alternatives will result in some erosion problems. Systems, such as those shown in Figures 7-4 and 7-5, that utilize underground pipelines to transport geothermal fluids from the reservoir to the process will cause greater surface disruptions and will result in more erosion impacts than systems where the wellhead is located adjacent to the process. A system not designed for reinjection of the fluid will also cause greater erosion than a system that is designed for reinjection, especially if the fluid is allowed to flow onto the ground into natural drainage pathways (See Figures 7-2 and 7-6). In addition,

TABLE 7-5 TOPOGRAPHIC DESCRIPTION OF GEOTHERMAL RESOURCE AREAS

RESOURCE AREA	TOPOGRAPHIC DESCRIPTION
NORTHERN CALIFORNIA	THE NORTHERN PART OF THE GEYSERS KGRA IS FLAT TO ROLLING LAND. THE SOUTHERN PORTION IS MOUNTAINOUS, WITH STEEP SLOPES, ROCKY OUTCROPS AND STREAM CANYONS. THE MAYACMAS MOUNTAINS PASS THROUGH THE SOUTHERN PORTION AND SLOPES RANGE FROM 30 - 40%. KGRA HAS SEVERAL VALLEYS, TWO MAN-MADE LAKES AND SEVERAL NATURAL LAKES.
SOUTHERN CALIFORNIA	THE KGRA'S IN THE IMPERIAL VALLEY ARE ALL ON FLAT DESERT LAND, WHICH IS IRRIGATED AND USED FOR AGRICULTURE. THE IRRIGATION SYSTEM AND THE FIELDS HAVE BEEN LAID TO SPECIFIC GRADES.
SOUTHWEST IDAHO	THE BRIGHAM CITY SITE IS IN A WIDE FLAT VALLEY BORDERED BY THE WASATCH MOUNTAINS ON THE EAST. THE RAFT RIVER SITE IS IN A VALLEY THAT IS GENERALLY LEVEL, WITH RELIEF LIMITED TO SMALL GULLIES AND RIDGES. THE VALLEY IS BORDERED BY THE JIM SHOE MOUNTAINS.
SOUTHEAST IDAHO	MOUNTAIN HOME IS LOCATED IN THE WESTERN SNAKE RIVER BASIN ON RELATIVELY FLAT LAND INTERSPERSED WITH A FEW GENTLY ROLLING HILLS. OTHER AREAS OF INTEREST ARE GENERALLY IN LOWLANDS ON EITHER SIDE OF THE SNAKE RIVER WITH FLAT TOPOGRAPHY, IN VALLEYS BORDERED BY FLAT TOPPED PLATEAUS OR MOUNTAINS.
ARIZONA	THE CHANDLER WELL IS ON FLAT DESERT LAND THAT IS IRRIGATED AND USED FOR AGRICULTURE. THE REGION HAS SEVERAL DRY STEAM WASHES AND ARROYOS AND IS BORDERED BY THE PHOENIX MOUNTAINS.
WASHINGTON	LONGMIRE HOT SPRINGS IS LOCATED IN THE RUGGED TERRAIN OF THE CASCADE MOUNTAINS IN A NATIONAL PARK.

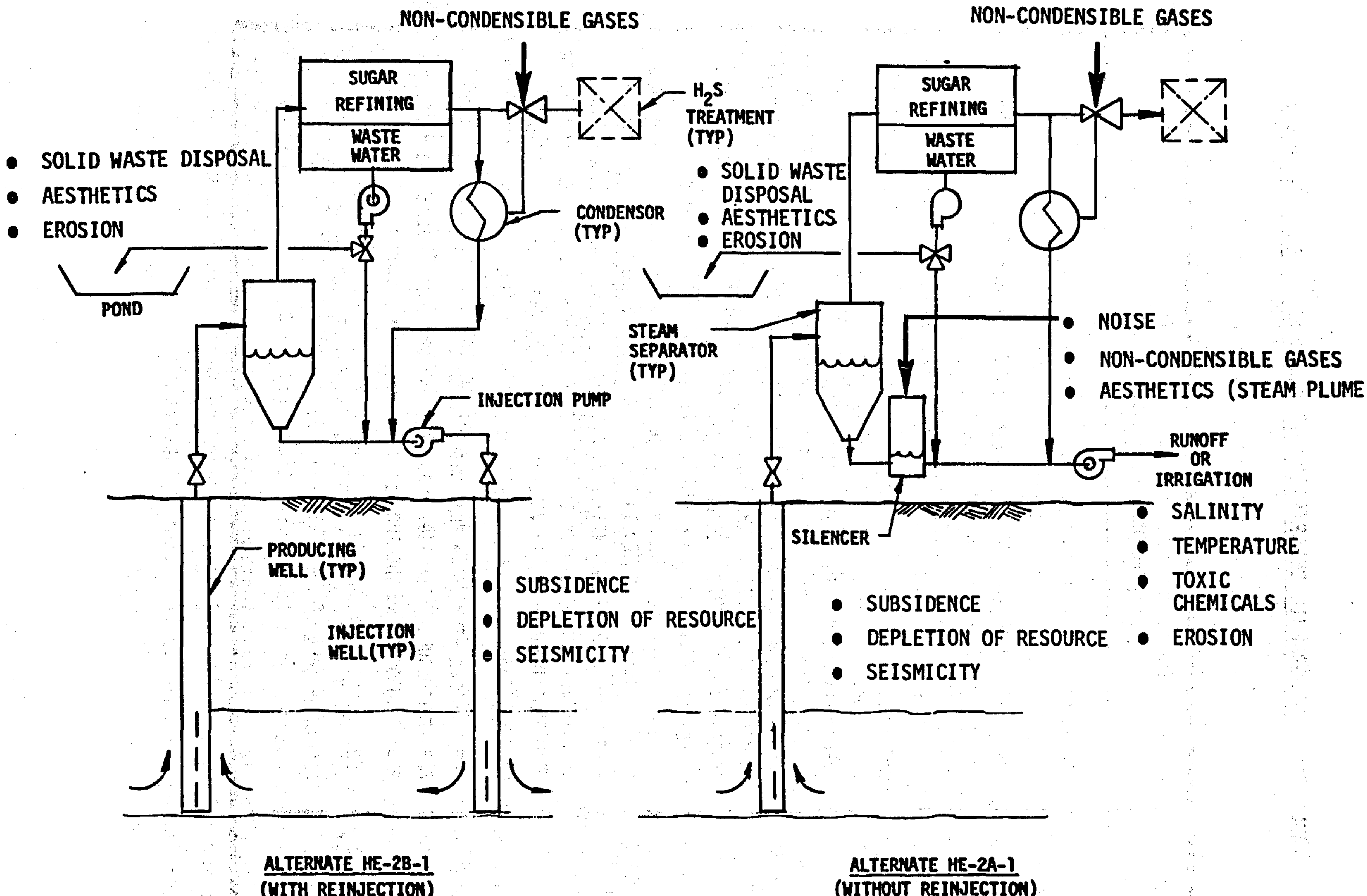


Figure 7-6 Sugar Refining Waste Water Utilization Alternate

in the systems where the process waste water is used for make up water for either reinjection or runoff and irrigation (see Figure 7-6), some of the process waste water must go to an evaporation pond. Upon evaporation of the fluid, the solid residue and waste must then be disposed of in an approved disposal site. Increased erosion may result from excavation of the pond and from wind erosion of the solid wastes stored in the pond.

7.7 Aesthetics

Developing a geothermal resource area for application of the heat to the sugar refining process will result in both temporary and permanent aesthetic impacts. Generally, less than one acre per drilling site will be required for excavation.

Geothermal development can be compatible with existing land uses. For example, at Lardarello, Italy, much of the geothermal field is used for agriculture while at the Geysers, much of the field is used for hunting and cattle grazing. However, geothermal development can alter existing land uses. In New Zealand, subsidence caused by geothermal production has resulted in a loss of hot springs and fumaroles and a change in the local tourist industry. In other areas, it is possible that geothermal fluids discharged to rivers could deleteriously affect fisheries and irrigated crops if the fluids are high temperature or low quality.

The amount of visual impact will vary depending on the type of geothermal system utilized. A system requiring the use of an underground pipeline to transport the fluid, such as the vertically drilled or the remote wellhead system shown in Figures 7-4 and 7-5, will disrupt a much larger surface area than a system that does not require a pipeline. The way in which the well flow effluent is handled can also have aesthetic impacts. As shown in Figures 7-1 and 7-6, a system that is not designed for reinjection will generate a steam plume from the silencer, as well as from testing procedures. These steam plumes are often visible for miles, especially in areas where the terrain is flat and the plume is not easily camouflaged by the natural topography.

If the process waste water is used as make up water for either the reinjection fluid or the runoff, an evaporation pond will be required for the excess amount of waste water. The scars left by a pond that is not rehabilitated can have a permanent visible impact, depending on the rate of revegetation. Site rehabilitation will minimize aesthetic impacts. Full consideration must be given to aesthetic design, placement of man-made structures, use of compatible colors, landscaping and vegetative restoration to minimize visual impacts.

In most of the six resource areas, development of the resource will require that men and equipment be placed onto relatively pristine lands. Impacts to the aesthetic quality are usually caused by visual obstructions or intrusions associated with excavation, drilling operations, pipeline and facility construction and vegetation removal, etc. Also, alteration of existing land uses can be considered to have an aesthetic impact. The extent of the visual impact at each site will vary depending on the topography, vegetative cover, the methods employed to minimize the impact, the proximity to population centers, parks and forest, etc. It should be noted that the extent to which aesthetic impacts are perceived will vary from person to person and is very subjective.

Of the six resource areas identified, two areas, northern California and Washington, will encounter problems in developing their geothermal resources because of aesthetic impacts. Clear Lake County in Northern California is a recreational area of high aesthetic quality. Potential impacts are of major concern to the public. Longmire Hot Springs in Washington is situated in a National Park where aesthetic impacts are also of major concern. In addition, since both areas are in areas of rugged terrain,more land might have to be excavated to provide room for roads and drilling sites.

7-8 Geothermal Versus Fossil Fuel

One environmental issue of great concern is the impact of geothermal development relative to other sources of power. Table 7-6 shows the advantages and disadvantages of a geothermal system versus a fossil fuel system.

TABLE 7-6 ADVANTAGES AND DISADVANTAGES OF A GEOTHERMAL VERSUS A FOSSIL FUEL SYSTEM

	ADVANTAGES	DISADVANTAGES
GEOTHERMAL	• AVAILABLE IN USABLE FORM AT PRODUCTION SITE • NO PROCESSING OR TREATING (SUPPORT OPERATIONS) • IMPACTS RESTRICTED PRIMARILY TO PRODUCTION SITE • FEWER WATER REQUIREMENTS • H_2S IS PRIMARY POLLUTANT OF CONCERN • MINERAL BY PRODUCTS (SULFUR RECOVERY) • POTENTIAL FOR DESALINIZATION, IRRIGATION, ETC. • MAY BE A RENEWABLE RESOURCE	• CANNOT TRANSPORT RESOURCE EXTENSIVELY • LOCATED IN REMOTE AREAS • DISPOSAL OF BRINES • NOT FULLY DEFINED LEGALLY
FOSSIL FUEL	• AFFECTS SMALLER NEWER AREA • MORE FLEXIBLY LOCATED • TECHNOLOGY MORE DEVELOPED • FUEL IS CAPABLE OF BEING TRANSPORTED • MINERAL BY PRODUCTS (SULFUR RECOVERY)	• REQUIRES PROCESSING OR TREATMENT • IMPACTS EXTEND TO MINING, PROCESSING, TRANSPORTATION, POWER PRODUCTION, WASTE DISPOSAL • NON-RENEWABLE RESOURCE • GREATER WATER REQUIREMENTS • EMISSIONS (CO_2, SO_x, NO_x, PARTICULATES)

7. REFERENCES

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7-18 Illingworth, R.R., Factors Contributing to Annoyance by Geothermal Steam Well Venting Noise at the Geysers. Paper Presented to the Geothermal Environmental Seminar, October 27-29, 1976, Lake County, California.

8. CLOSELY RELATED PROCESSES

Process applications that are closely related to the beet sugar geothermal applications derived in this study will be identified for potential technology transfer.

The evaporation process, using medium pressure steam, which is a key element in beet and cane sugar refining, is also used in the chemical industry in the manufacture of caustic soda and table salt and in the pulp and paper industry.

Pulp drying applications are likened to alfalfa drying and it is noted that the same equipment could probably be utilized for seasonal balanced utilization of the geothermal energy supply system with significant beneficial economic impact as discussed in Section 6.

Also, it is observed that other crop dehydration applications with low temperature requirements (250°F) such as onion, grain or seed drying could be economically cascaded from the geothermal outputs of the sugar applications as described in Section 6.

9. EFFECT/NEED FOR TECHNOLOGICAL/POLICY CHANGES

Assessments were conducted to evaluate the impact of technological or institutional factors or changes which might affect the potential for conversion to geothermal heat. Results are described below.

9.1 Geothermal Loan Guaranty Program

The Geothermal Loan Guaranty Program became effective on June 25, 1976, following publication of regulations on May 26, 1976 (10 CFR 790). The purpose of the program is to accelerate commercial development of geothermal energy by the private sector by minimizing the financial risk to lenders. Congress appropriated $30 million to cover $200 million in loan guarantees for FY 1977. Maximum limits stipulated in the program are $25 million for a single project and $50 million for a single borrower. Loans are guaranteed for up to 30 years; however, no new guarantees will be authorized past 1984. The borrower must comply with appropriate federal, state and local administrative and environmental regulations, which can delay the loan guaranty; however, such delays are expected to be minor.

ERDA has stated that it will give top priority to projects that will most quickly result in the production of useful energy from geothermal resources, that will utilize new technological components and that will exploit the potential of new geothermal resource areas. Lower priority will be given to projects that propose exploration operations or the acquisition of land or leases.

In the past, it has been difficult to find adequate numbers of skilled personnel to work in the field. Most people work for successful ventures, such as The Geysers, and are reluctant to work elsewhere. In addition, it has been difficult for new workers to enter the market. As a result, there has been a shortage of personnel for geothermal drilling. Financial institutions and private investors have been reluctant to commit funds for geothermal development. They feel that investing in geothermal drilling has a greater risk than investing in oil and gas drilling for two reasons. First, investors must be assured of the reliability of the reservoir. Although oil, gas and geothermal resources are defined, the reliability of the geothermal resource is still relatively unknown, especially for hydrothermal fields. This lack of assurance makes geothermal drilling a higher risk venture than oil and gas drilling. Second, tax incentives for oil and gas drilling are greater than for geothermal drilling. These tax incentives make investment in the oil and gas area more attractive to capitalists than investment in the geothermal area. The competition for capital has discouraged geothermal development. The Geothermal Loan Guaranty Program may help ease this problem by encouraging development of geothermal energy while simultaneously reducing the financial risks.

9.2 Tax Policy

Due to the diversity of the possible types of geothermal uses and applications, the geothermal resource is difficult to fully describe. The Geothermal Steam Act of 1970 (84 Stat. 1573, 30 U.S.C. 1001-1025) left unresolved the question of whether or not geothermal steam and associated geothermal resources are to be regarded as part of the water resources of a state; therefore, subject to applicable state water laws, which vary from state to state. In some states (i.e., Hawaii) geothermal resources have not yet been fully defined legally.

The uncertainty of how to legally classify geothermal resources (water, mineral, heat, etc.) has resulted in taxation problems. Federal tax law does not have a provision for a depletion allowance specifically for geothermal energy. However, in a case held before the tax court in 1969, Reich vs. Commissioner of IRS (52 T.C. 700, 1969), it was held that the natural steam at The Geysers qualified for a depletion allowance and that the producers were entitled to write off as expenses the untangible costs of drilling and developing The Geysers field. The reasoning in the case was that the steam at The Geysers is not ordinary ground steam fed by constant water seepage and inexhaustible, but steam that is locked in closed spaces like natural gas, not replenished by seepage and depletable. Therefore, it was reasoned, that it should be subject to the same tax treatment as natural gas with respect to the depletion allowance and intangible drilling and development costs. It should be noted that the reasoning of this case may not be extended to depleting hot water and hot rock resources.

Since the Federal Tax structure does not contain a depletion allowance that applies to most geothermal resources, it appears that it might discourage investment of venture capital in exploration, drilling and field development. It should be noted that efforts are being made to change this aspect of the existing structure and that progress is being achieved.

9.3 Technology Improvements

Technology improvements which could improve the economic feasibility of geothermal applications to sugar refining have been as follows:

a. Well stimulation completion and workover technology improvements to increase flow, thus reducing the most significant cost element of the energy supply system.

b. Heat exchanger scaling control improvements such as acid treatment, continuous cleaning (modified AMERTAP) direct contact and fluidized bed improvements to improve approach efficiency and minimize capital and maintenance costs.

c. Non-condensible H_2S gas control and abatement improvements. This would permit using lower cost more efficient steam separators as described in Section 3.

d. Lower temperature evaporation sequence technology improvements to permit maximum cost effective resource temperature utilization.

9.4 Environmental and Administrative Regulations and Constraints

A substantial portion of the development time-to-market for a geothermal resource is the time required to obtain approvals from government agencies. Approval delays have a direct bearing on the economics of development and thus directly affects the potential of geothermal prospects.

The most significant differences in administrative requirements for geothermal development are exhibited state by state, rather than prospect by prospect. The procedure and regulations adopted by local county governments are generally similar within any state. Most counties assume a minor role in the regulation of geothermal activity and the state assumes the major responsibility, except in California, where local government exercises significant control.

Environmental and adminstrative requirements consist of various regulations and permit procedures that vary by state and county and with federal, state or private land ownership. The most complex series of procedures are found in development on federal lands and usually the interaction of regulatory authority between federal, state and county levels of government is required.

Table 9-1 shows the administrative and environmental requirements for development of geothermal resources on state or private land for California, Arizona, Idaho, Oregon, Washington and Utah. These states were selected based on the data developed in Section 2, which identified potential sugar manufacturers within economic proximity to geothermal resources. Table 9-1 shows the procedures and applicable regulations or regulatory agencies for exploration and development and production.

As this table shows, regulatory requirements for development of geothermal resources are generally identical, with the exception of the leasing procedures. The California procedures and regulations are the most stringent in the nation. These tough requirements stem primarily

ADMINISTRATIVE REQUIREMENTS FOR DEVELOPMENT OF GEOTHERMAL RESOURCES ON STATE OR PRIVATE LAND.

STATE	EXPLORATION		DEVELOPMENT AND PRODUCTION		
	PROCEDURE	REGULATIONS (OR REGULATORY AGENCIES)	PROCEDURE	REGULATIONS (OR REGULATORY AGENCIES)	NEW REGULATIONS TO BE PROMULGATED
CALIFORNIA	EIR REQUIRED BY COUNTY,[a] REVIEW BY SEVERAL AGENCIES: • DIVISION OF OIL AND GAS • AIR RESOURCES BOARD • STATE WATER RESOURCES CONTROL BOARD • ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION DRILLING PERMIT BY OIL & GAS DEPT. LAND USE PERMIT BY COUNTY	APPLICABLE COUNTY REGULATIONS STATE OIL & GAS DEPT. REGIONAL WATER QUALITY BOARD AIR POLLUTION CONTROL BOARD	EIR REQUIRED BY COUNTY, REVIEW BY SEVERAL AGENCIES: • DIVISION OF OIL AND GAS • AIR RESOURCES BOARD • STATE WATER RESOURCES CONTROL BOARD • ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION DRILLING PERMIT BY OIL & GAS DEPT. LAND USE PERMIT BY COUNTY	APPLICABLE COUNTY REGULATIONS STATE & OIL GAS DEPT. REGIONAL WATER QUALITY BOARD AIR POLLUTION CONTROL BOARD PUBLIC UTILITIES COMMISSION	NONE IMMEDIATE
ARIZONA	DRILLING PERMIT. OIL & GAS COMMISSION IS SOLE AUTHORITY.	OIL & GAS COMMISSION REGULATIONS. APPLICABLE COUNTY REGULATIONS	STATE LANDS DEPT. APPROVES SITING OF PROJECTS (POWER PLANTS) ON STATE LANDS. NO SITING AUTHORITY EXISTS FOR PRIVATE LAND. DRILLING PERMIT BY OIL & GAS COMMISSION.	APPLICABLE COUNTY REGULATIONS. STATE POWER AUTHORITY. OIL & GAS COMMISSION.	NONE IMMEDIATE
IDAHO	DRILLING PERMIT. WATER RESOURCES DEPT. IS SOLE AUTHORITY. COUNTY MAY REQUIRE SPECIAL USE PERMIT IN DESIGNATED AREAS	WATER RESOURCES DEPT. DRILLING REGULATIONS, PATTERNED ON OIL & GAS PROCEDURES.	DEVELOPMENT PERMIT. WATER RESOURCES DEPT. ISSUES APPROVAL AFTER REVIEW BY HEALTH & WELFARE DEPT. PUBLIC UTILITIES APPROVE SITING OF PRODUCTION PLANTS.	WATER RESOURCES DEPT. REGULATIONS. PUBLIC UTILITIES APPLICABLE COUNTY REGULATIONS.	EXPANSION OF COUNTY REQUIREMENTS UNDERWAY.
OREGON	APPLICATION FOR AN EXPLORATION PERMIT IS MADE TO THE DIVISION OF STATE LANDS AND ISSUED BY THE DEPT. OF GEOLOGY AND MINERAL RESOURCES.	DEPT. OF GEOLOGY AND MINERAL INDUSTRIES REGULATIONS OF GEOTHERMAL WELLS. DEPT. OF ENVIRONMENTAL QUALITY ENVIRONMENTAL REGULATIONS	APPLICATION FOR A GEOTHERMAL RESOURCES LEASE IS MADE TO DIVISION OF STATE LANDS, ISSUED BY DEPT. OF GEOLOGY AND MINERAL RESOURCES IN COMPLIANCE WITH DEPT. OF ENVIRONMENTAL QUALITY REGULATIONS. EIR REQUIRED BEFORE APPROVAL OF LEASE.	DEPT. OF GEOLOGY AND MINERAL INDUSTRIES REGULATIONS OF GEOTHERMAL WELLS. DEPT. OF ENVIRONMENTAL QUALITY ENVIRONMENTAL REGULATIONS	NONE IMMEDIATE
WASHINGTON	DRILLING PERMIT FOR STATE AND PRIVATE LANDS. DEPT. OF NATURAL RESOURCES, DIVISION OF GEOLOGY AND EARTH RESOURCES, IS SOLE AUTHORITY EIS REQUIRED FOR PROPOSED LEASING PROGRAM (COULD CAUSE 1 - 4 YEAR DELAY) BY DEPT. OF ECOLOGY.	DEPT. OF NATURAL RESOURCES DIVISION OF GEOLOGY AND EARTH RESOURCES REGULATIONS. DEPT. OF NATURAL RESOURCES WILL BE LEAD AGENCY. APPROVAL BY DEPT. OF ECOLOGY.	DEVLOPMENT PERMIT, DEPT. OF NATURAL RESOURCES, DIVISION OF GEOLOGY AND EARTH RESOURCES. EIS REQUIRED FOR DEVELOPMENT/PRODUCTION (COULD CAUSE 1 YEAR DELAY) BY DEPT. OF ECOLOGY	DEPT. OF NATURAL RESOURCES DIVISION OF GEOLOGY AND EARTH RESOURCES REGULATIONS. DEPT. OF NATURAL RESOURCES WILL BE LEAD AGENCY. APPROVAL BY DEPT. OF ECOLOGY.	NEW REGULATIONS BEING DEVELOPED BY DEPT. OF NATURAL RESOURCES.
UTAH	DRILLING PERMIT. WATER RIGHTS DIVISION IS SOLE AUTHORITY. COUNTY MAY REQUIRE LAND USE PERMIT.	DRILLING REGULATIONS PATTERNED AFTER OIL & GAS PROCEDURES. APPLICABLE COUNTY REGULATIONS.	DRILLING PERMIT, WATER RIGHTS DIVISION IS SOLE AUTHORITY. COUNTY MAY REQUIRE LAND USE PERMITS	DRILLING REGUALTIONS OF WATER RIGHTS DIVISION APPLICABLE COUNTY REGULATIONS.	NEW REGULATIONS NOW IN PROCESS FOLLOWING RECENT GEOTHERMAL LEGISLATION.

[a]EIR IS REQUIRED BY STATE LANDS COMMISSION FOR STATE LAND; HOWEVER, EXCEPT FOR THE GEYSERS AREA, ALL LAND OF GEOTHERMAL INTEREST IN CALIFORNIA IS EITHER PRIVATE OR FEDERAL.

TABLE 9-1

from the California Environmental Quality Act, which insures that all local governments control new development in a manner consistent with the policy guidelines (environmental goals) of the Act. All proposed projects, public or private, which are judged to offer potential significant impact to the environment, may not be implemented without preparation and evaluation of an Environmental Impact Report (EIR). The local (county) governments are the responsible agency in issuing the requirement for an EIR, and participate jointly with numerous state and local agencies in the approval of a proposed project. In other states, such as Arizona, Utah, and Idaho, environmental impact reports are not required by either local or state authorities and approval of a proposed geothermal project is accomplished by relatively simple processes.

Figure 9-1 illustrates the administrative requirements for development of geothermal resources on federal lands. Requirements for development of geothermal resources on federal lands are distinct in that the concept of full development is used from the outset. Issuing a federal lease for geothermal development is contingent on the suitability and approval of total development. This initial requirement is the most significant impediment to developers of geothermal resources on federal lands. Conversely, the greatest administrative deterrents facing developers on state or private lands may often occur downstream of exploration activities, when more stringent approval procedures are applied. Administrative problems increase if a private/state land development spreads into adjacent federal land. Currently, geothermal activities on federal lands are also subject to state and local requirements. However, as

Generally, the severity of constraints generated by regulations and policies depends on the following five factors:

- the number of reviewing agencies in the approval process (i.e., as many as 40 in California and 1 in Arizona)
- the delays associated with the approval processes. Many procedures do not stipulate a time target.

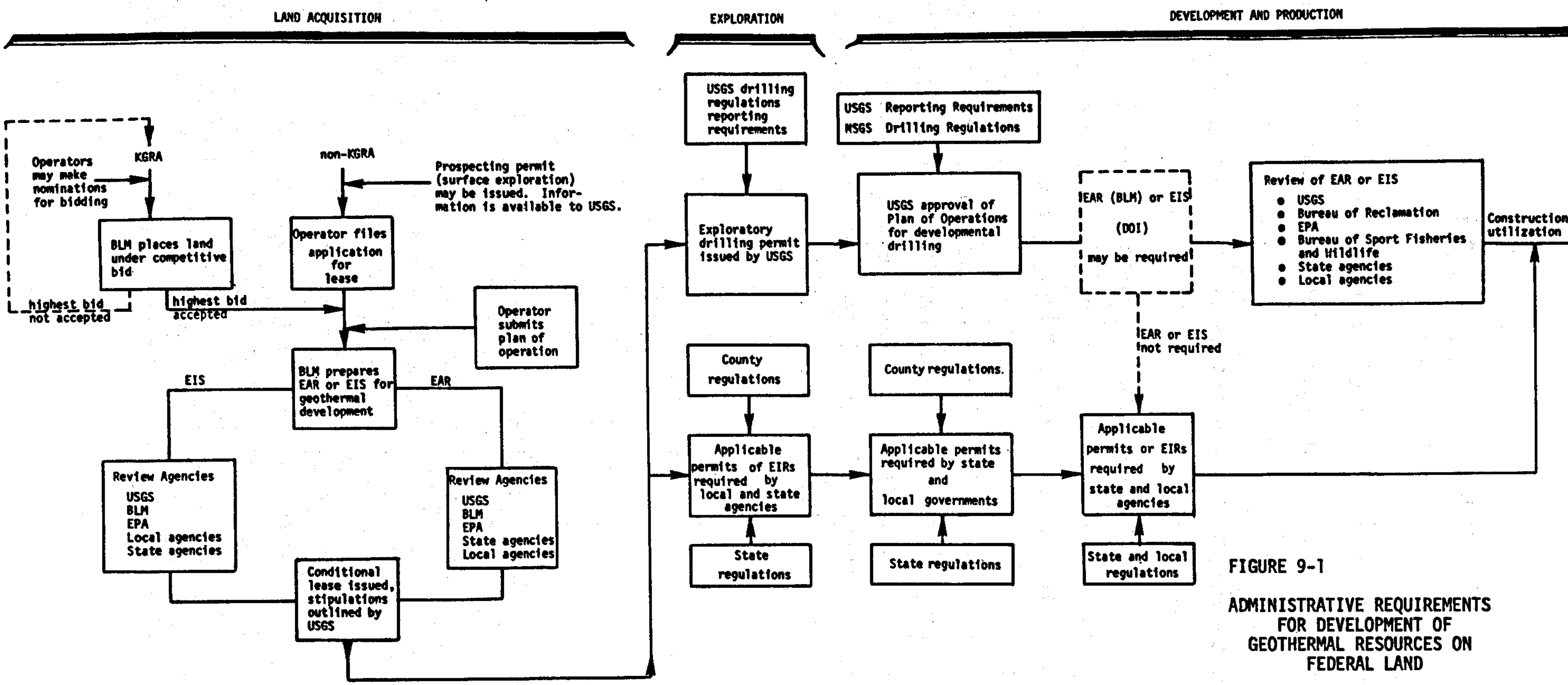


FIGURE 9-1

ADMINISTRATIVE REQUIREMENTS FOR DEVELOPMENT OF GEOTHERMAL RESOURCES ON FEDERAL LAND

- the nature and disposition of the reviewing agencies.
- the disposition of private-interest groups, such as the Sierra Club.
- the complexity and the technical consequences of requirements to be implemented

The situation shows promise of improving, however, in that the California Energy Resources Conservation and Development Commission is set up to reduce redundancies and overlaps in regulatory jurisdiction, and have had a program in the development stage for seven months which intends to define limits of jurisdiction, methods of cooperation and minimizing of red tape and delays in permitting decisions. Also, steps are being taken at the federal and state level to allow the use of a single document to suffice for an EIS and EIR, when a project overlaps federal and state or private lands.

10. TECHNOLOGY TRANSFER

The objective of this task was to identify potential beet sugar factory users of geothermal energy and disseminate the results of the study to stimulate early development of commercial applications.

The study identified sugar beet factories which are located near geothermal anomalies and offer potential for retrofit or relocation are tabulated below in order of decreasing potential:

	Factory Location	Area	Firm
(1)	Brawley	Imperial Valley, CA	Holly
(2)	Chandler	Arizona	Spreckels
(3)	Nyssa	Southwest Idaho	Amalgamated
(4)	Mini-Cassia	Southeast Idaho	Amalgamated
(5)	Idaho Falls	Southeast Idaho	U & I
(6)	Nampa	Southwest Idaho	Amalgamated
(7)	Twin Falls	Southeast Idaho	Amalgamated

Based on these study findings, telephone conversations relating the study results have been held during the course of the study with the following firm representatives:

- Holly Sugar - George W. Miles, Jr., Senior, Vice President - Planning
- Spreckels - Temple C. Rowe, Chief Engineer
- Amalgamated - Sylvester M. Heiner, Chief Engineer
- U & I - Franklin Wareham, Manager of Engineering

Additionally, several conversations have been held with Van R. Olsen, Director of Public Affairs for the United States Beet Sugar Association.

Syd Willard of the California Energy Resources Conservation and Development Commission has been invited to, and attended all review meetings with ERDA.

Copies of the final report will be sent to each of the aforementioned interested parties in lieu of conducting a workshop at the conclusion of the study.

11. FUTURE WORK PLAN

The sugar industry would be required to invest significant amounts of capital for a retrofit or new plant conversion from a fossil fuel to a fossil fuel/geothermal system for refining sugar. Therefore, to meet the objectives of this study, TRW has solicited from representatives of the sugar industry the type of information they would require before seriously considering geothermal conversion.

In Section 2, selected areas of geothermal resources within economic range to beet-growing areas and factories were identified. Sugar manufacturing representatives were selected from the list of potential geothermal users described in Section 2. Representatives that were contacted include the following:

- George Miles - Holly Sugar
- Temple Rowe - Spreckels Sugar
- Franklin Wareham - U&I, Inc.
- Sylvester Heiner - Amalgamated Sugar
- Van R. Olsen - U.S. Beet Sugar Association

The major areas of concern or steps to achieve geothermal adaptation which were identified by the sugar representatives contacted are:

- Indication of technical and economic feasibility
- Assurance of reservoir capacity
- Assurance of operational feasibility.

11.1 Indication Of Technical And Economic Feasibility

Representatives from the sugar industry have stated that for sugar manufacturers to participate in a geothermal project, the technical and economic feasibility of using geothermal fluids to replace fossil fuels as an energy source must first be determined. Once the technical feasibility has been established, it must then be determined that the cost of geothermal energy be competitive with the industry's other alternatives. In the short term, geothermal energy will have to be competitive with natural gas and residual fuel oil in California and coal in Utah and Idaho, while in the long term, geothermal will have to be competitive with coal only.

Prior to considering the use of geothermal energy in their factories, sugar manufacturers must have credible predictions of feasibility for the following economic factors:

- the amount of capital outlay.
- overhead, operation and maintenance.

In communicating with the sugar manufacturers the approach and findings of this study were discussed and generally appeared to be received as credible indicators of technical and economic feasibility.

11.2 Assurance of Reservoir Capacity

Because of its perishable nature, the sugar beet crop cannot be stored and must be processed immediately. The process requires a source of energy that is dependable for the length of the sugar campaign, 24 hours per day, 7 days per week for 4-6 months. For some California manufacturers, a reliable energy source has become a primary area of concern, since they have had severe curtailments of natural gas in 1976 and 1977 and have been forced to seek other fuel sources, such as residual fuel oil, to maintain operation of sugar factories.

Before proceeding with a retrofit or new plant, the sugar manufact- urers contacted by TRW indicated that a well defined geothermal reservoir would be required. Definition of the reservoir should include tests or demonstrations which:

- indicate total energy of the reservoir.
- estimate recoverable energy.
- determine reservoir longevity at various production rates.
- estimate off-sugar season regeneration capability.

Specifically, reservoir testing should demonstrate minimum reliability of temperature, flow rate and pressure for the duration of a typical sugar campaign (24 hours per day, 24 hours per day, 4-6 months per year). In addition, reservoir testing should demonstrate a reservoir lifetime requirement of 30 years to match the life of an ammortized factory. For consideration of a new plant, the reservoir or geothermal well must be located within or on the perimeter of the beet growing area to accomodate acceptable trucking distances established by the sugar industry. ERDA activities, such as those being conducted at Raft River and soon to be conducted under the Geothermal Loan Guaranty Program with McCullough Oil must consider the above demonstration requirements to be applicable to future sugar industry utilization.

11.3 Assurance of Operational Feasibility

A sugar factory must have equipment that operates with minimum operational maintenance and downtime for 24 hours per day, 7 days per week of a 4 to 6 month sugar campaign. Therefore, in considering the adaptation of a geothermal system to sugar refining, the reliability of the equipment is of utmost concern to the industry. Reliability concepts will not be accepted by the industry based solely on engineering feasibility studies, such as this current study. Therefore, operational field testing of critical hardware is required to demonstrate equipment reliability of potential geothermal system approaches. To determine the impact on equipment cost and economic feasibility, operational field testing must:

- demonstrate operability throughout the length of a typical sugar campaign with minimum performance degradation due to the geothermal application (i.e., scaling, corrosion).
- establish equipment redundancy requirements to minimize or eliminate downtime.
- demonstrate technical operability of utilizing low grade geothermal heat for pulp drying and steam generation.

East Mesa is an ideal location for demonstration testing since (1) ERDA has existing facilities for non-electric testing, (2) geothermal fluids at East Mesa are typical for the region in which the Holly Sugar Brawley plant is located, and (3) the Brawley plant is in nearby for sugar juice or beet pulp demonstration test requirements. Demonstration testing of prime candidate concepts to satisfy the requirements identified above are described in the following sections.

11.3.1 Demonstration Test Experiments

The demonstration equipments and experiments described herein are based on previously identified technology developments required to resolve engineering and economic uncertainties. Economic feasibility evaluations have indicated the requirement for a cascaded boiler to beet pulp dryer retrofit application at the Brawley factory using 300°F geothermal brines. The proposed experiment is configured with cascaded sub-scale boiler and dryer demonstration units as indicated schematically in the piping and instrument diagram (P&ID) of Figure 11-1.

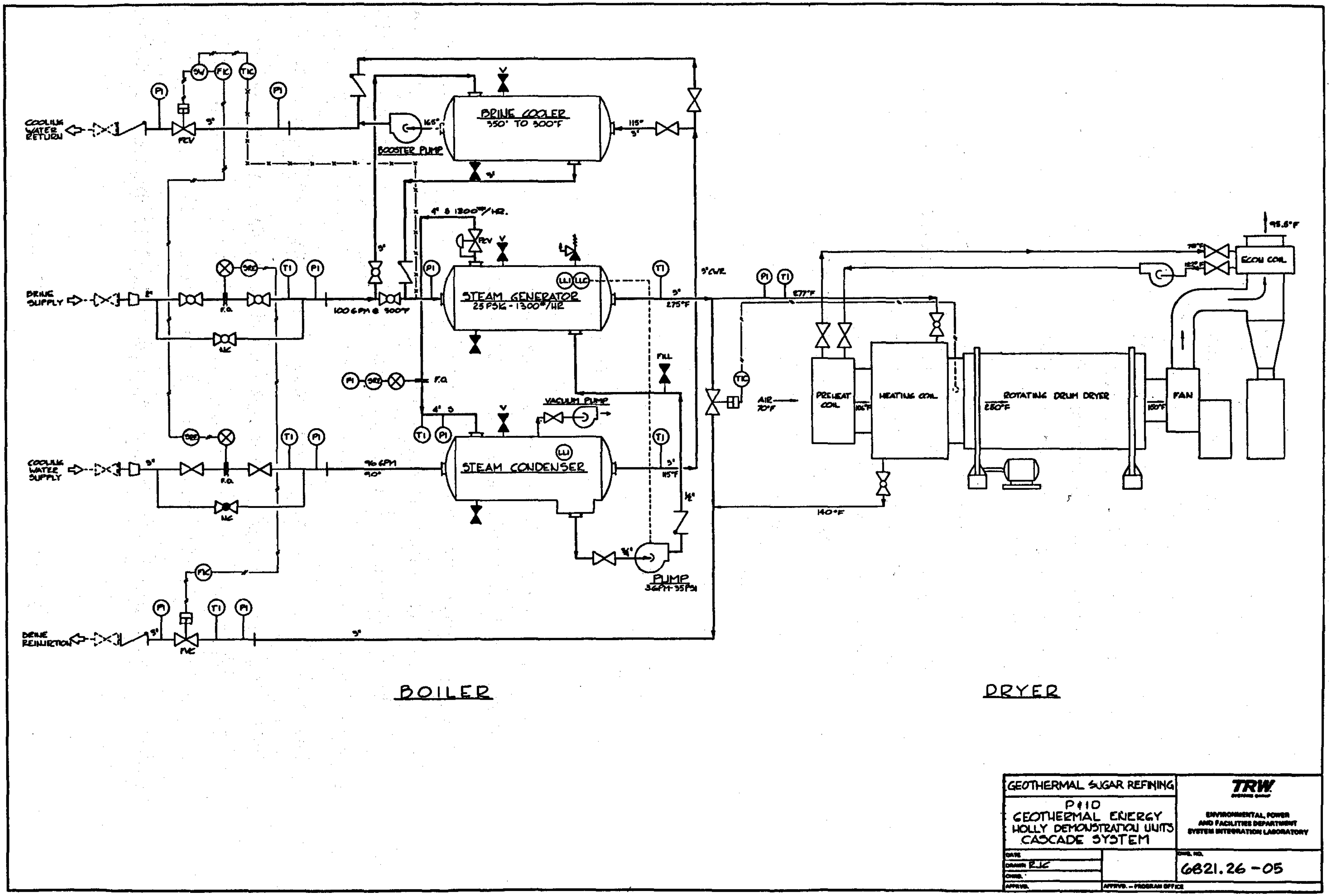

COOLING WATER RETURN
BRINE COOLER
350° TO 300°F
BOOSTER PUMP
BRINE SUPPLY
100 GPM @ 300°F
4" @ 1300#/HR.
STEAM GENERATOR
25 PSIG - 1300#/HR
275°F
STEAM CONDENSER
VACUUM PUMP
FILL
COOLING WATER SUPPLY
9 GPM
90°
115°F
PUMP
3GPM-35PSI
BRINE REINJECTION
AIR
70°F
PREHEAT COIL
HEATING COIL
ROTATING DRUM DRYER
280°F
FAN
ECON COIL
140°F
BOILER
DRYER
GEOTHERMAL SUGAR REFINING
P&ID
GEOTHERMAL ENERGY
HOLLY DEMONSTRATION UNITS
CASCADE SYSTEM
TRW
ENVIRONMENTAL, POWER AND FACILITIES DEPARTMENT
SYSTEM INTEGRATION LABORATORY
DRAWN RJC
6821.26 -05

FIGURE 11-1

The experiments are designed to be conducted using one of the test stations at the ERDA East Mesa Geothermal Component Test Facility. The instrumentation and control spools for brine supply and return and cooling water supply and return as shown on Figure 11-1 are as previously designed by TRW under ERDA Contract E (04-3)-1140 for use at this test facility. Additionally the experiment configuration includes a brine cooler to permit bypass control of experiment brine supply inlet temperatures at any temperature from 275 to 350 ± 5°F.

The demonstration units are to be skid mounted with prefabricated flanged spools and connections for future testing or commercial use at Union/Brawley, McCullough/Brawley or Chevron/Heber wells. Additional equipment requirements, not shown, for remote testing would include a power supply, instrument air compressor and cooling tower with pump.

The proposed general arrangement of equipment at a typical ERDA East Mesa test station is shown in the test facility plan of Figure 11-2. Boiler and dryer experiments are described in the following sections.

11.3.1.1 Boiler Experiment

The objectives of the boiler experiments are to:

a) Demonstrate the predicted boiler operation with the close temperature approaches required by the application.

b) Determine length of operating time before performance degradation, due to scaling, requires cleaning. (This information is needed to establish redundancy and maintenance requirements and operational cost impacts.)

c) Evaluate chemical cleaning methods. (Minimize maintenance costs.)

d) Determine optimum application tube velocities and minimum impact brine exit temperatures. (Substantiate the application applicability of the EPRI test findings discussed in Section 3.)

The boiler configuration as shown in Figure 11-2 is predicated on the observation that the sub-scale unit major impact is a function of tube length and diameter. Therefore, the test configuration is based on a bundle including tubes of a length and diameter previously selected for the Holly/Brawley

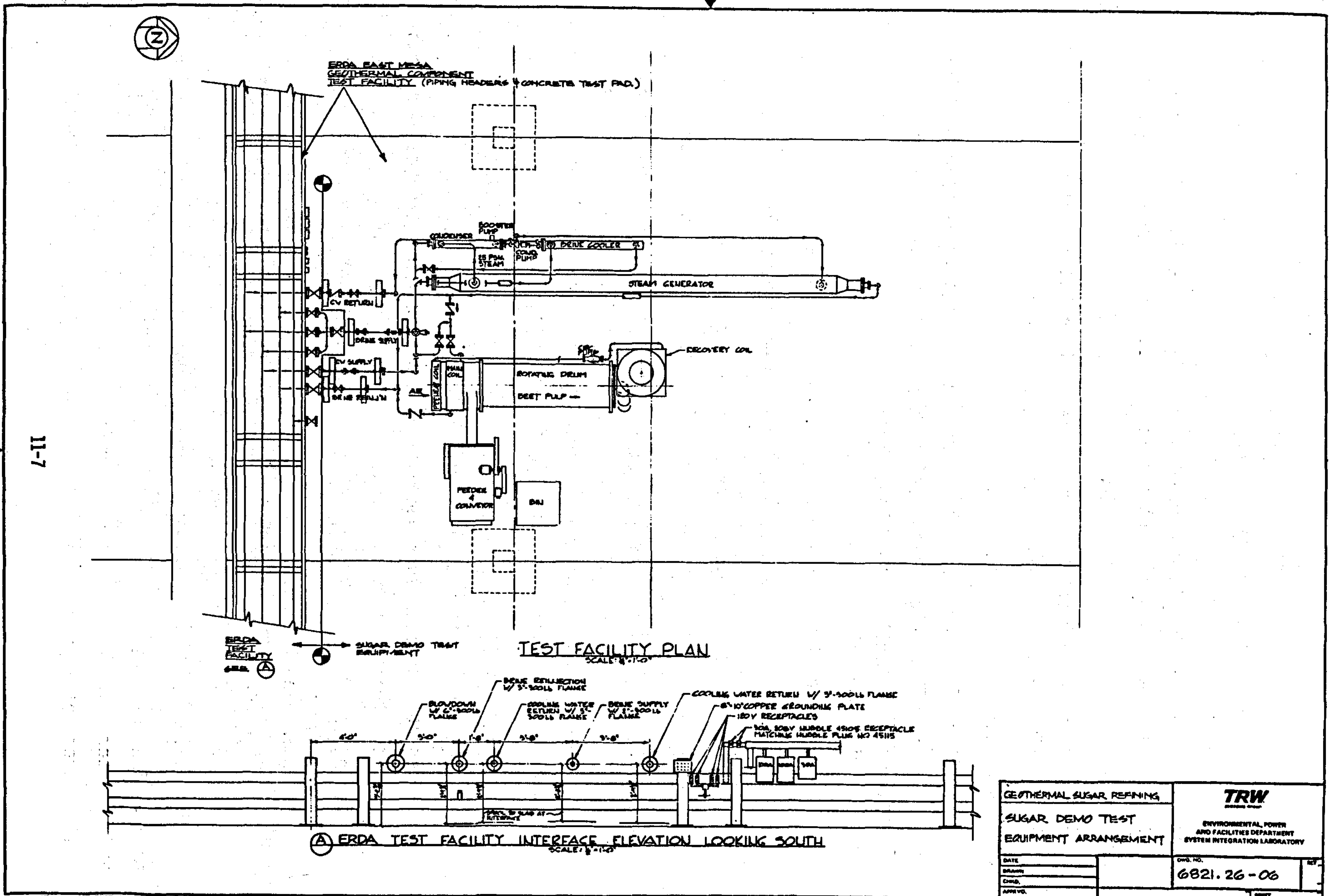

ERDA EAST MESA
GEOTHERMAL COMPONENT
TEST FACILITY (PIPING HEADERS & CONCRETE TEST PAD.)
BOOSTER PUMP
CONDENSER
BRINE COOLER
COND. PUMP
STEAM GENERATOR
CV RETURN
BRINE SUPPLY
CV SUPPLY
BRINE RETURN
AIR
RECOVERY COIL
ROTATING DRUM
BEET PULP
FEEDER & CONVEYOR
BIN
ERDA TEST FACILITY
SUGAR DEMO TEST EQUIPMENT
TEST FACILITY PLAN
BRINE REINJECTION W/ 3"-300Lb FLANGE
BLOWDOWN W/ 6"-300Lb FLANGE
COOLING WATER RETURN W/ 3"-300Lb FLANGE
BRINE SUPPLY W/ 3"-300Lb FLANGE
COOLING WATER RETURN W/ 3"-300Lb FLANGE
8"x10" COPPER GROUNDING PLATE
120V RECEPTACLES
30A, 208V HUBBLE 4510S RECEPTACLE MATCHING HUBBLE PLUG NO 4511S
4'-0"
3'-0"
1'-8"
3'-8"
3'-8"
A ERDA TEST FACILITY INTERFACE ELEVATION LOOKING SOUTH
GEOTHERMAL SUGAR REFINING
SUGAR DEMO TEST
EQUIPMENT ARRANGEMENT
TRW
ENVIRONMENTAL, POWER AND FACILITIES DEPARTMENT
SYSTEM INTEGRATION LABORATORY
DATE
DRAWN
CHKD.
APPVD.
DWG. NO.
6821.26-06

FIGURE 11-2

factory retrofit application described in Section 3. As shown the bundle includes carbon steel tubes of 1 inch diameter, and approximately 40 feet long.

The boiler test loop as shown in Figure 11-1 includes a closed steam condensing loop to minimize clean water make-up requirements in the desert test location.

Equipments and arrangements shown are conceptual only as developed for preliminary cost estimating and to assist in planning detailed design activities and test facility implementation.

11.3.1.2 Dryer Experiment

The objectives of the beet pulp dryer experiments are to:

a) Demonstrate the predicted dryer capability to dry beet pulp to the required moisture content using a low temperature heat source.

b) Determine the dryer drum speed, internal design and overall configuration required to obtain the required dwell time for low temperature drying. (Information required to establish dryer configuration and number required and thus investment cost impact.)

c) Evaluate and establish design requirements for maximizing cost effectiveness of the heat recovery system.

d) Determine length of operating time before coil performance degradation, due to sealing, requires cleaning. (This information is needed to establish redundancy and maintenance requirements and operational cost impacts.)

e) Determine optimum heating coil design tube configuration and chemical cleaning methods (minimize maintenance costs).

The larger configuration as indicated in Figure 11-2 is based on a Heil Model SD45-12 , three pass drum unit dehydrator modified with a geothermal brine heating coil and heat recovery system as identified in Section 2 of this study. The arrangement and equipment shown is conceptual only as developed for preliminary cost estimating and to assist in planning detailed design activities and test facility implementation. Extensive internal design (baffling), speed control and other modification detailed designs must be accomplished prior to fabrication for test.

The cascaded geothermal brine feedstock piping to the dryer is configured with a controlled by-pass loop to permit test flow variations during tests. Inlet test temperature variations from 275 to 350 ± 5°F can be accomplished, with the boiler inoperative, in the manner described in Section 11.3.1.1

The modified test dryer proposed can be utilized for experiments or commercially with drying other crops, such as alfalfa, after this test program is complete.

11.3.1.3 Implementation Planning

As previously identified a prime test requirement is the demonstrated operability of the geothermal application throughout the length of a typical sugar campaign with minimum maintenance or downtime. In keeping with this and the requirement for beet pulp from the Brawley factory for dryer tests the test planning must be keyed to a sugar campaign at the Holly/Brawley factory. As indicated on Figure 11-3 the next sugar campaign will start in April 1978 and run through August 1978. The plan as shown in Figure 11-3 indicates that with allowances for procuring long lead items coupled with time required to design the equipments, the test program must be initiated in June or July of 1977 in order to be operable during the entire 1978 campaign. The alternative is to slip the test program one year.

Having established the time requirements for demonstrating "assurance of a operational feasibility" we examined the potential time requirements to satisfy another sugar manufacturer expressed concern that of "assurance of reservoir capacity." As shown in Figure 11-4 we have projected credible estimates of the time required for reservoir evaluations of the McCullock and Union wells in the near vicinity of the Holly/Brawley factory. If the test demonstration program proceeds as previously described it appears that Holly Sugar would have sufficient information to make a decision to proceed, in the fall of 1978, providing reservoir and equipment tests demonstrated applicability

FIGURE 11-3

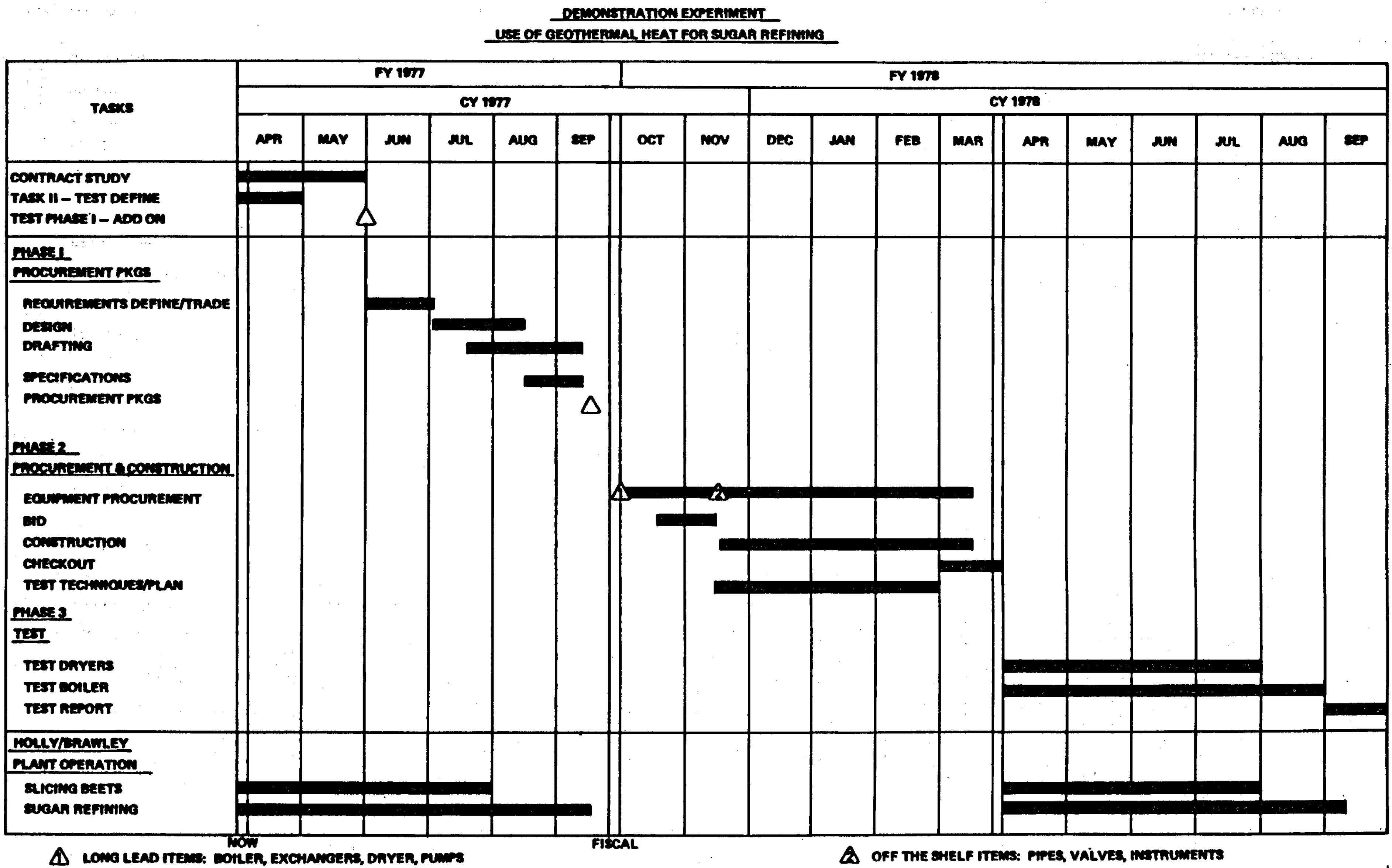
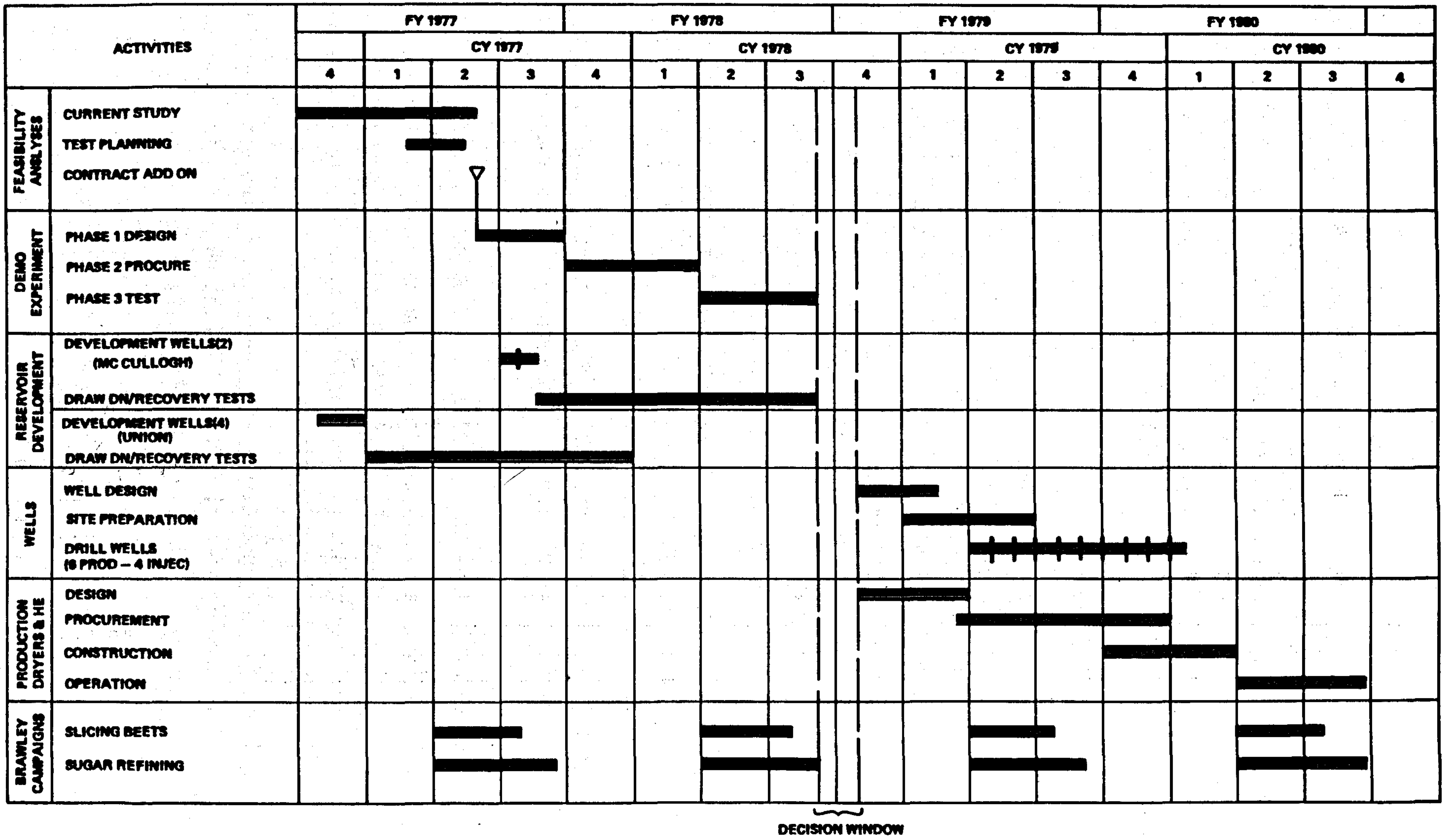

DEMONSTRATION EXPERIMENT
USE OF GEOTHERMAL HEAT FOR SUGAR REFINING
TASKS
FY 1977
FY 1978
CY 1977
CY 1978
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
CONTRACT STUDY
TASK II – TEST DEFINE
TEST PHASE I – ADD ON
PHASE I
PROCUREMENT PKGS
REQUIREMENTS DEFINE/TRADE
DESIGN
DRAFTING
SPECIFICATIONS
PROCUREMENT PKGS
PHASE 2
PROCUREMENT & CONSTRUCTION
EQUIPMENT PROCUREMENT
BID
CONSTRUCTION
CHECKOUT
TEST TECHNIQUES/PLAN
PHASE 3
TEST
TEST DRYERS
TEST BOILER
TEST REPORT
HOLLY/BRAWLEY
PLANT OPERATION
SLICING BEETS
SUGAR REFINING
NOW
FISCAL
LONG LEAD ITEMS: BOILER, EXCHANGERS, DRYER, PUMPS
2 OFF THE SHELF ITEMS: PIPES, VALVES, INSTRUMENTS

FIGURE 11-4

ACCELERATED DEVELOPMENT SCHEDULE
GEOTHERMAL APPLICATION TO SUGAR REFINING



and the sugar market conditions warranted a factory retrofit at Brawley. A decision to proceed at that time could result in geothermal supplemented energy utilization in the Brawley sugar campaign of 1980. It is noted however that the predicted implementation scheduled activities of testing and factory retrofit are series in nature and this coupled with the seasonal sugar processing activity would result in a slip of one year to 1981, if the test program is not initiated this summer.

11.4 Recommendations

There is a need for demonstration technology experiments to resolve engineering and economic uncertainties identified in the process conversion analyses and the expressed concern of industry. The recommended experiment configuration is illustrated in Figure 11-2 to conduct experiments aimed at the following objectives.

(a) Demonstrate the ability of the cascade system to operate reliably on actual geothermal fluids.

(b) Demonstrate operability throughout the length of a typical sugar campaign with minimum maintenance or performance degradation due to the geothermal application.

(c) Determine base performance characteristics and establish design criteria for varying equipment sizes and flow parameters.

The specific tasks to accomplish these objectives are as follows:

(a) Design, fabricate and install the cascade test equipments of Figure 1 at the ERDA East Mesa Geothermal Component Test Facility before the next Brawley sugar campaign; i.e., April, 1978.

(b) Perform demonstration experiments during the period April through September, 1978, using beet pulp from the Brawley factory to accomplish the following:

   (1) Determine length of operating time of boiler and dryer heat exchangers before performance degradation due to geothermal fluid scaling.

(2) Evaluate chemical scale cleaning methods on boiler and dryer heat exchangers.

(3) Determine optimum boiler and dryer tube velocities and minimum scale impact brine exit temperatures.

(4) Determine parametric performance characteristics of the boiler and dryer for geothermal brine inlet temperatures varied from 275 to 350°F.

(5) Demonstrate the predicted boiler operation with the close temperature approaches required by the application.

(6) Determine the dryer drum speed, internal drum baffle modifications and overall configuration required to obtain the required dwell (residence) time for low temperature drying.

(7) Evaluate performance and establish design requirements for maximizing cost effectiveness of the pulp dryer heat recovery system.

(8) Demonstrate the predicted dryer capability to dry beet pulp to the required moisture content using a low temperature geothermal heat source.

(c) Relocate the skid mounted cascade test equipments of Figure 1 to a potential producing geothermal wellhead (e.g. Union or McCulloch Wells) near the Brawley factory and repeat the aforementioned tests of (b) above for a period of 2 to 3 months.

APPENDIX A

GEOTHERMAL BOILER DESIGN STUDY

Southwestern Engineering was contracted for Engineering Service to perform an analysis for a full size steam boiler using geothermal fluid for the energy source. Southwestern Engineering, a leading manufacturer of heat exchangers, was chosen for their expertise in this field and the technical knowledge they could add to the program. Basic criteria established for the geothermal fluid and steam product together with the resultant data are included in this appendix.

Attachment
TRW 1981-JW-7.012
March 7, 1977

HEAT EXCHANGER DESIGN
ENGINEERING SERVICES

Southwest Engineering shall provide engineering services and computer time as required to develop parametric cost and evaluation data for the following geothermal boiler services:

	Case I	Case II
Geothermal (Tube Side)		
Inlet Temperature	300°F	350°F
Inlet Pressure	80 PSIA	175 PSIA
Pressure Drop	15 PSI	15 PSI
Outlet Temperature	Vary	Vary
Flow Rate (GPM)	TBD	TBD
Steam (Shell Side)		
Inlet Condensate Temp	250°F	250°F
Inlet Condensate Press	25 PSIG +	25 PSIG +
Steam Outlet Temp	268°F	268°F
Steam Outlet Press	25 PSIG	25 PSIG
Flow	75,000 LB/HR	75,000 LB/HR

Design optimizations will consider duty effects of the following tube-side fouling factors:

a. Design = 0.002

b. Clean = 0

c. Dirty = 0.004

Design optimizations will show preference to:

a. Minimizing geothermal fluid flow

b. Configurations suitable for periodic tube side mechanical scale cleaning.

The deliverable data shall consist of graphs, tabulations and sketches as required to characterize the heat exchangers satisfying the aforementioned requirements. The parametric performance data shall be quantified in terms of square feet of heat transfer surface or costs.

Southwestern Engineering
Subsidiary of
Tyler Corporation

Attachment
TRW 1981-JW-7.012
March 7, 1977

Geothermal Boiler Design Study
TRW P.O. A75334LBCE
SEC File 29895 - JOB 5829-04

March 15, 1977

This study was based on the performance conditions specified in TRW letter 1981-JW-7.012 dated March 7, 1977.

Sizes and heat transfer surfaces were determined for a number of different brine outlet temperatures and corresponding flow rates for each case, using a fouling factor of 0.002. These designs were accomplished by making a number of computer runs with an arbitrary tube length limitation of 40 feet in order to obtain reasonable length to diameter proportions. Some of the specific results came out with 40 foot tubes and others with 36 foot tubes because of velocity limitations as combined with the optimum number of tube passes. The number of tube passes varied from 1 to 3 depending on brine flow rate. Figure III shows the general configuration and range of sizes of the equipment.

Brine pressure drop ranged from 3 psi to 9 psi, with velocities ranging from 4.3 to 7.4 feet per second. Tube diameter was set at 1 inch O.D.; however, in any final optimized design, this could be different depending on specific design conditions.

Costs shown are based on the assumption that all material is carbon steel. These costs of course, are approximate but should be within 10 to 15 percent of current actual values.

After determining a number of different size units for each case, the performance was recomputed for zero and 0.004 fouling factors using the same brine flow rates and sizes as was determined in the design runs.

Surfaces and costs are plotted in Figures I-A and II-A. Duties are plotted in Figures I-B and II-B for the alternate fouling conditions. Figures I and II are inter-related, since the same flow rates and corresponding surfaces are involved.

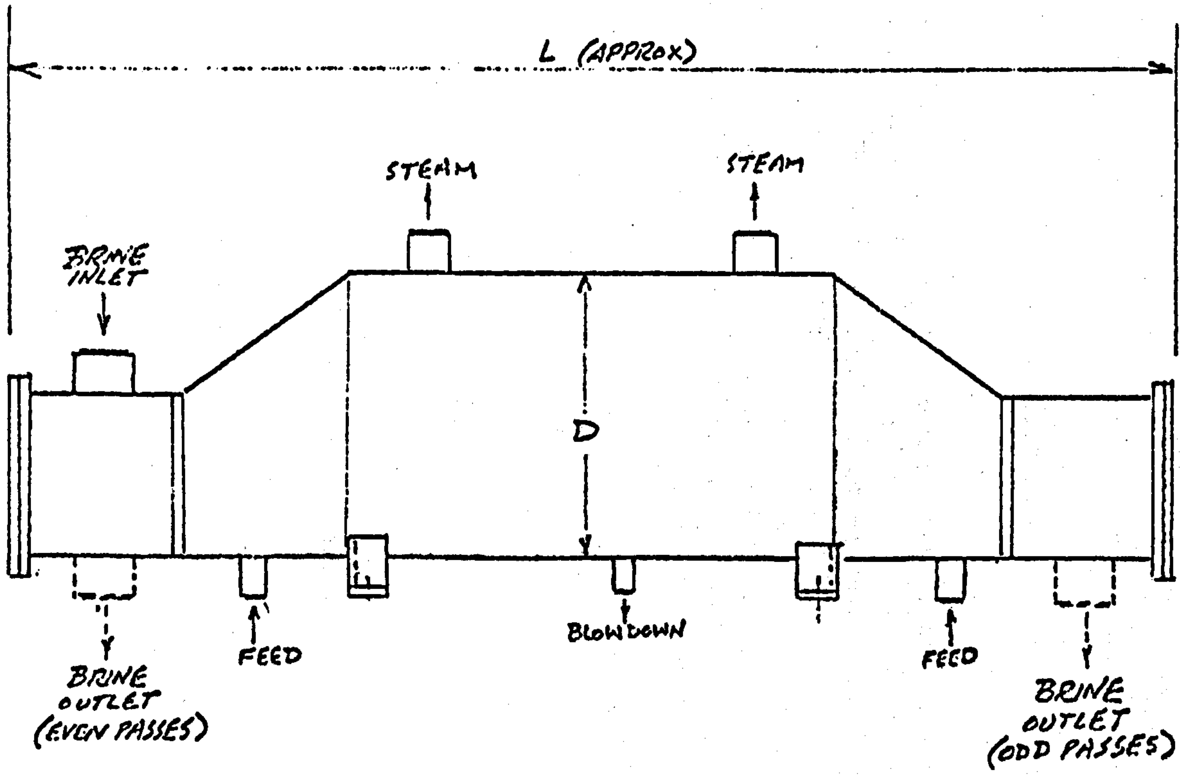
If there are any further questions or if additional data is desired, please contact Mr. Abe Yarden or Mr. Nate Gainsboro.

NR Gainsboro
N. R. Gainsboro
Engineering Staff Consultant

NRG/mn

attachments

SOUTHWESTERN ENGINEERING COMPANY
6111 EAST BANDINI BOULEVARD
LOS ANGELES, CALIFORNIA 90040



	L	D
CASE I	43' TO 49'	78" TO 84"
CASE II	41' TO 45'	61" TO 70"

CUSTOMER: TRW
DESIGN STUDY
P.O. A75348LBCE

JOB 5829

GEOTHERMAL BOILER (TYPICAL)

SIZE:
TYPE: CKN
ITEM:

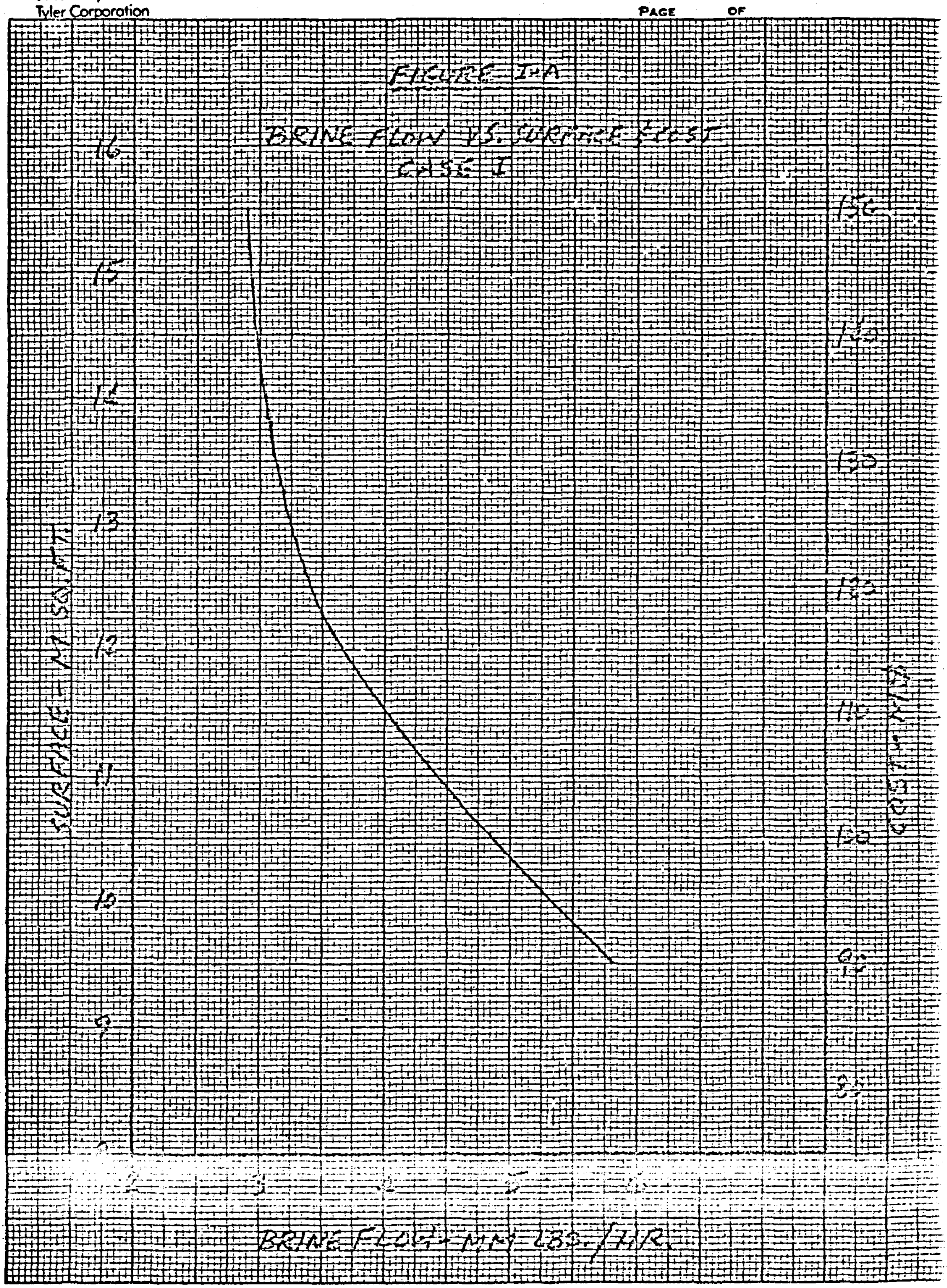
SERIAL No
P.O. No
FILE No
-UNIT REQUIRED

APPROX. WT. (EMPTY) LBS

	DES. PRESS.	DES. TEMP.
SHELL	PSI.	°F
TUBES	PSI.	°F

REV
FIGURE III
DATE 2/1/77

Southwestern Engineering 6111 E. Bandini Blvd., P.O. Box 54940, Terminal Annex Los Angeles, Cal. 90054, Tel: 213/685-9
Subsidiary of
Tyler Corporation
SEC FILE 29895
PAGE OF



SEC JOB 5829


FIGURE II-A
BRINE FLOW VS. SURFACE & COST
CASE II.
SURFACE - M SQ. FT.
8
7
6
5
4
3
80
70
60
50
40
30
COST
1.0
1.2
1.4
1.6
1.8
BRINE FLOW - MM LBS./HR.

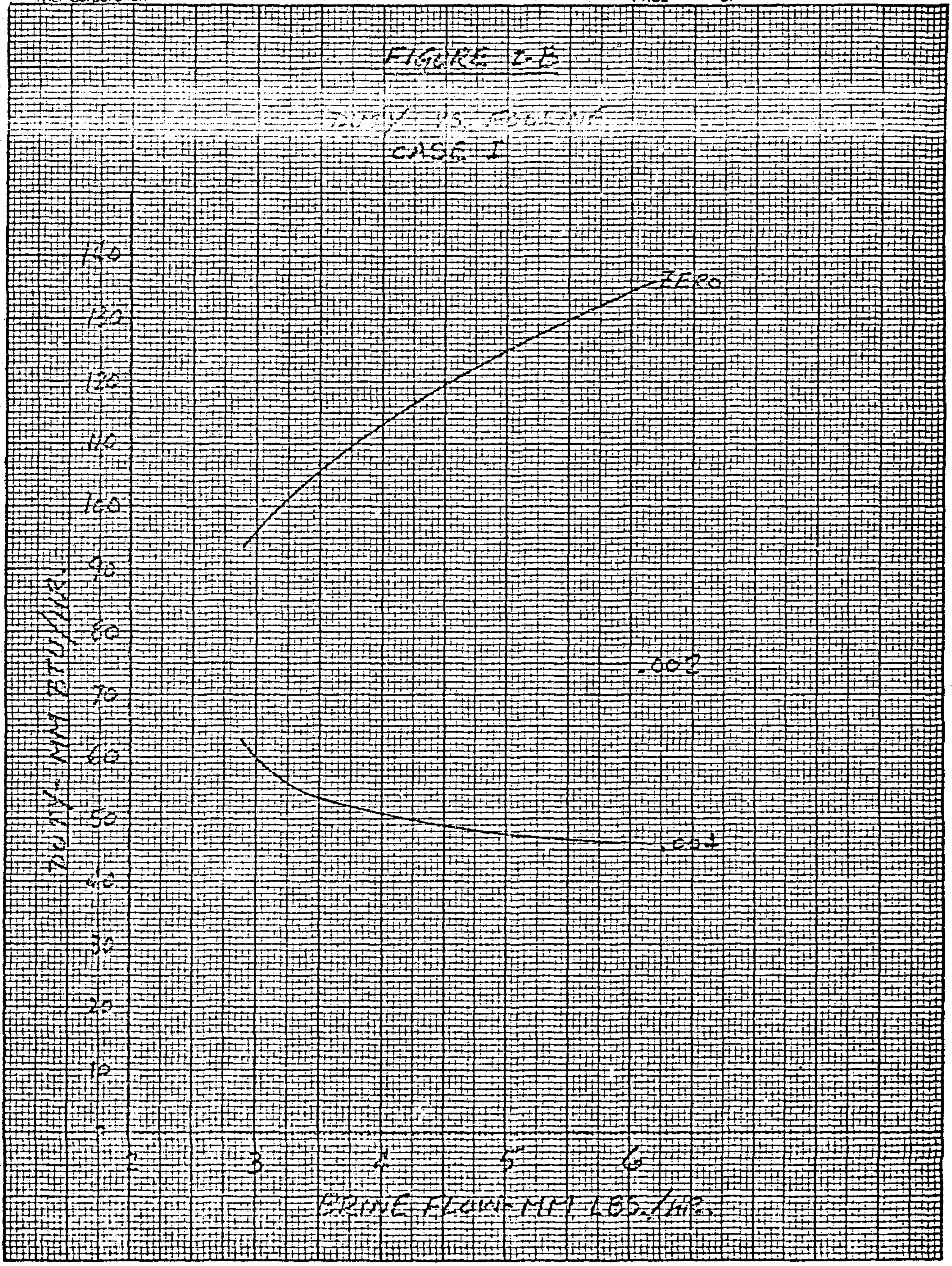


FIGURE I-B
DUTY VS. FOULING
CASE I
DUTY - MM BTU/HR.
BRINE FLOW-MM LBS./HR.
ZERO
.002
.004
2
3
4
5
6
10
20
30
40
50
60
70
80
90

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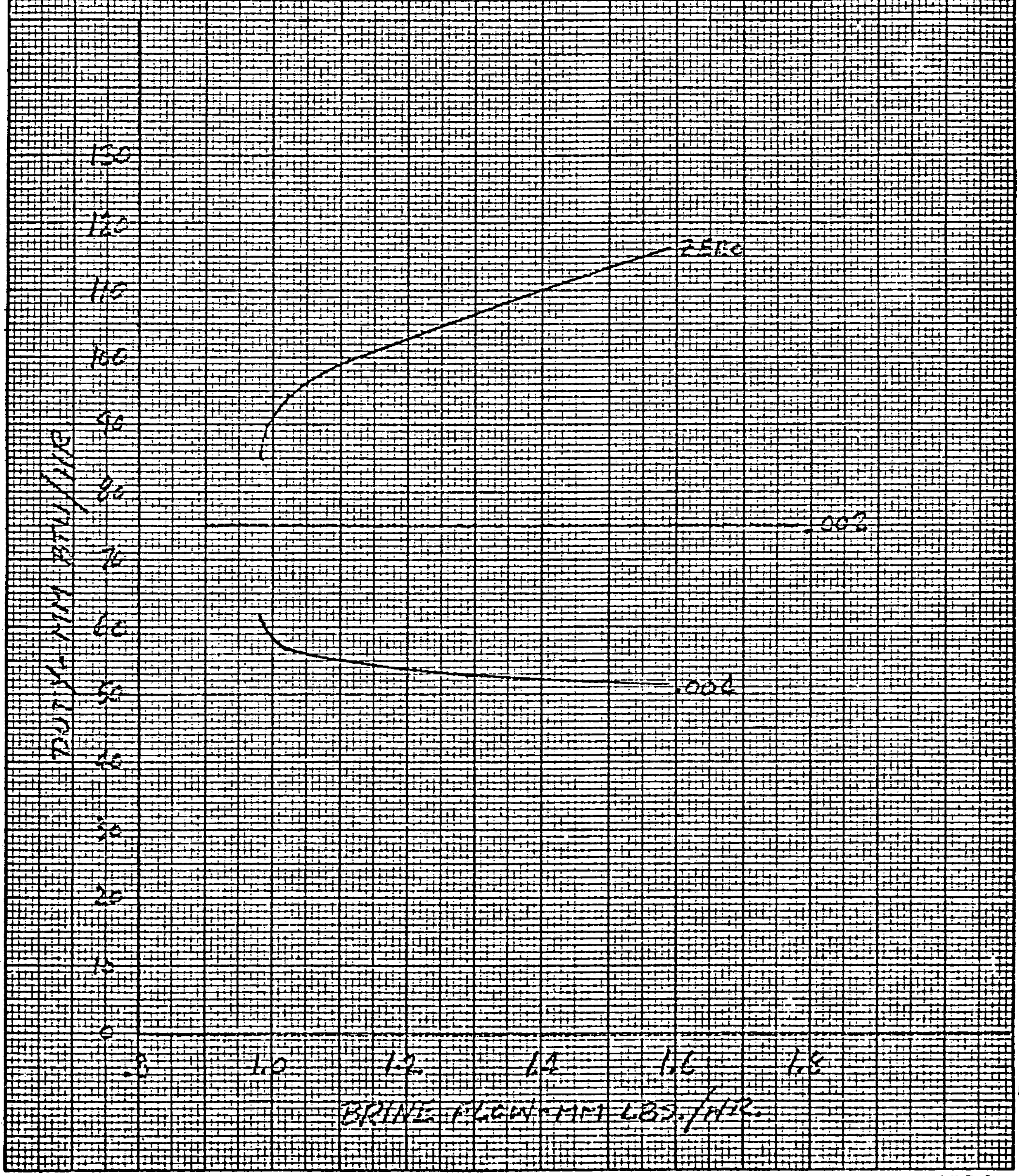
FIGURE II-B

DUTY vs. FOULING

CASE II



SEC JOB 5829

APPENDIX B

PULP DRYER THERMODYNAMIC ANALYSIS

A separate analysis was performed to assess the impact on beet-pulp drying of using heat from a geothermal source. The analysis considered thermodynamic effects only; no attempt was made to determine the effect on the quality of the resulting product. The analyses are included in this appendix.

In order to predict the performance of a low-temperature dryer, it is necessary to obtain some properties of the pulp in the dryer which are not available in the literature. These properties are the heat transfer between the drying stream and the pulp (Btu/hr-lb pulp F) and the evaporation rate from the pulp (lb H_2O/hr-psi-lb pulp).

Approximate values of these two coefficients were obtained by analyzing present high-temperature dryers and using the resulting values to analyze a low-temperature dryer. The effects of temperature on the heat transfer were predictable and included; however, any effect on the evaporation coefficient was not.

As expected, the results show that a low-temperature dryer, while capable of delivering a product with the required moisture content, is much less effective than a high-temperature dryer. Specifically, for the same volumetric flow of the drying stream, the rate of flow of pulp is reduced by a ratio of five to six, and the required residence or dwell time of the pulp in the dryer is increased by a factor of three to five.

These results coincide with dryer manufacturer's estimates of a total of 16 dryers to replace the existing three fossil-fueled units. In addition, other modifications could be necessary to retain the pulp in the dryer for the time required for the moisture content to be reduced to the proper level.

HOLLY BEET SUGAR PULP DRYING

OBJECTIVE OF THE ANALYSIS

TO DETERMINE THE CONDITIONS & CONSTRAINTS ON DRYING SUGAR BEET PULP WITH LOW-TEMPERATURE (~300°F) AIR.

APPROACH

USING TYPICAL OPERATING CHARACTERISTICS OF EXISTING BEET SUGAR PULP DRYERS, DETERMINE THE HEAT AND MASS TRANSPORT PROPERTIES OF THE PULP. THESE PROPERTIES MAY THEN BE USED TO CALCULATE THE TEMPERATURE AND MOISTURE OF THE PULP IN SIMILAR DRYERS WITH DIFFERENT OPERATING CONDITIONS.

SIMPLY STATED, THE HEAT TRASFERRED TO THE PULP FROM THE DRYING VAPOR IS USED TO SUPPLY THE LATENT HEAT TO EVAPORATE THE MOISTURE. ESSENTIALLY BUT TWO PULP PROPERTIES ARE REQUIRED:

K_2 Btu/(hr-F-lb pulp), THE HEAT TRANSFER COEFFICIENT WHICH INCLUDES SOME UNDETERMINED VALUE OF AREA PER POUND OF PULP.

K_3 lb mol evap/(hr-psi-lb pulp), THE EVAPORATION COEFFICIENT WHICH INCLUDES THE SAME UNDETERMINED AREA PER POUND OF PULP.

EXISTING DRYERS

THE CHARACTERISTICS OF EXISTING DRYERS AS OBTAINED FROM HOLLY SUGAR AND HANDBOOKS ARE LISTED IN TABLE 1. ALSO LISTED ARE THE VALUES USED IN THE PRESENT ANALYSIS. COMMENTS ON THE DIFFERENCES BETWEEN THE TWO COLUMNS ARE DISCUSSED AS THE VALUES ARE OBTAINED.

BURNER CALCULATIONS

BURNER CALCULATIONS ARE BASED ON THE FOLLOWING ASSUMPTIONS:

INLET AIR CONDITIONS:

AIR AT 70°F AND 50% RH, WHICH RESULTS IN THE FOLLOWING VOLUMETRIC FRACTIONS (MOLE FRACTIONS):

$N_2 = .7808$ $O_2 = .2066$ $CO_2 = .0003$ $H_2O = .0123$

TABLE I

COMPARISON OF TYPICAL EXISTING DRYER CHARACTERISTICS AND THOSE USED IN THE PRESENT ANALYSIS

CHARACTERISTIC	TYPICAL DRYER	PRESENT ANALYSIS	UNITS
FUEL	NATURAL GAS OR FUEL OIL	NATURAL GAS	—
DRY PULP FLOW	13,200	13,200	LB/HR
INLET MOISTURE	80 4	80 4	% LB H_2O/LB PULP
OUTLET MOISTURE	9 .099	9 .099	% LB H_2O/LB PULP
VAPOR INLET TEMP.	1200 MAX	1193	°F
VAPOR OUTLET TEMP	250	250	°F
PULP INLET TEMP	70	70	°F
DRY PULP OUTLET TEMP	180	180	°F
EXHAUST FLOW RATE	10^5	10^5	ACFM
OXYGEN, VAPOR INLET	<4	12	%
MOISTURE, VAPOR OUTLET	30	28.8	%
RECYCLED OUTLET VAPOR	~25	0	%
BURNER-DRYER EFFICIENCY	?	91.6	%
PREDOMINANT PULP TEMP DURING DRYING	140	150	°F
RESIDENCE TIME IN DRYER	30	30	MINUTES

HEAT REQUIRED PER DRYER:

13,250 LB/HR SOLIDS, $c_p = .4$ Btu/lb F, $\Delta T = 110 F^{\circ}$ — $q = .583 \times 10^6$ Btu/hr

53,000 LB/HR H_2O

1310.4 NOT EVAP $c_p = 1$ Btu/lb F, $\Delta T = 110 F^{\circ}$ — $q = .144$

51689.6 EVAP $\Delta h = 1164 - 38$ Btu/lb — $q = \underline{58.202}$

Σ = 2869.1 lb moles/hr.

TOTAL $q = \underline{58.93 \times 10^6 \text{ Btu/hr}}$

NO CARBON MONOXIDE IN COMBUSTION PRODUCTS, ALSO NO DISSOCIATION OF PRODUCTS AND NO NITROGEN OXIDES PRODUCED.

MOLAL VOLUMES AT 250°F

512.1 CUFT/LB MOL (H_2O), 518.26 (OTHER EXHAUST PRODUCTS)

NATURAL GAS BURNER

REACTIONS:

$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$$
$$C_2H_6 + 3\tfrac{1}{2}O_2 \rightarrow 2CO_2 + 3H_2O$$
$$C_3H_8 + 5O_2 \rightarrow 3CO_2 + 4H_2O$$
$$C_4H_{10} + 6\tfrac{1}{2}O_2 \rightarrow 4CO_2 + 5H_2O$$

	MOLE FRAC*	MW	MOLES/MOLE NAT GAS YIELD			INLET			
			N_2	H_2O	CO_2	N_2	O_2	H_2O	CO_2
CH_4	.9288	16.042	–	1.8576	.9288	7.0204	1.8576	.1106	.0027
C_2H_6	.0417	30.068	–	.1251	.0834	.5516	.1460	.0087	.0002
C_3H_8	.0093	44.094	–	.0372	.0279	.1757	.0465	.0028	.0001
C_4H_{10}	.0029	58.120	–	.0145	.0116	.0712	.0188	.0011	+0
O_2	.0003	32	–	–	–	-.0011	-.0003	-0	-0
N_2	.0148	28.016	.0148	–	–	–	–	–	–
CO_2	.0022	44.01	–	–	.0022	–	–	–	–
	1.0	17.253 calc.							
		17.44* act							
MOLES AIR REQ'D = 10.0126						7.8178	2.0686	.1232	.0030 (1)
MOLES EXHAUST			7.8326	2.1576	1.0569				

HEATING VALUE	ACTUAL	CALCULATED	
Btu/cuft	1055*	1029	(FROM SUM OF CONSTITUENTS)
Btu/lb	23366	23383	
Btu/lb mole	407512	403427	

USED

(MAJOR DIFFERENCES IN CALCULATED & ACTUAL VALUES FROM LUMPING TRACE CONSTITUENTS (H_2S, C_2H_2, HIGHER H-C) AS C_4H_{10})

* NATURAL GAS PROPERTIES FROM RALPH OWENS, SCGC, 673-3020 x 284

THEN TO RELATE EXHAUST MOLE FRACTION, FUEL FLOW, & EXCESS AIR

$$N_{CO_2} = 1.0569\,F + .0003\,E$$

$$N_{O_2} = .2066\,E$$

$$N_{N_2} = 7.8326\,F + .7808\,E$$

$$N_{H_2O} = 2.1576\,F + .0123\,E + 2869.1$$

$$6\times10^6\,(CFH) = 518.26\,(N_{CO_2} + N_{O_2} + N_{N_2}) + 512.10\,N_{H_2O}$$

$$MF = N_{H_2O}/\Sigma N$$

WHERE N = LB MOLES IN EXHAUST/HR
E = LB MOLES EXCESS AIR/HR
F = LB MOLES FUEL/HR
MF = MOLE FRAC H_2O IN EXHAUST FROM DRYER

THE SOLUTION, BY MATRIX INVERSION (HOLLYZ):

M-F H2O EXH	DRYER INLET ---- MOLES/MOLE FUEL ---- N2	O2	H2O	CO2	EXCESS AIR	FUEL MOLE/HR.
.2800	49.26758	10.96371	2.81033	1.07282	53.06734	136.43
.2810	47.23904	10.42696	2.77837	1.07204	50.46931	142.19
.2820	45.36851	9.93202	2.74891	1.07132	48.07365	147.96
.2830	43.63822	9.47418	2.72165	1.07066	45.85761	153.72
.2840	42.03297	9.04943	2.69636	1.07004	43.80171	159.48
.2850	40.53968	8.65431	2.67284	1.06947	41.88920	165.25
.2860	39.14703	8.28581	2.65090	1.06893	40.10558	171.01
.2870	37.84518	7.94134	2.63039	1.06843	38.43825	176.78
.2880	36.62553	7.61862	2.61118	1.06796	36.87619	182.54
.2890	35.48053	7.31565	2.59314	1.06752	35.40975	188.31
.2900	34.40353	7.03068	2.57617	1.06711	34.03039	194.07

A HEAT BALANCE CAN THEN BE PERFORMED:

$h_{Bic} = h_{\text{BURNER INLET FOR AIR FOR COMPL COMBUSTION}} = \sum_{j=1}^{4} h_{ij} N_{ij}$

$= 36910$ Btu/lb mole FUEL USING N_i FROM LINE (1)

$h_{BiE} = h_{\text{BURNER INLET FOR EXCESS AIR}}$

$= 3686.3 \cdot E$ Btu/lb mole FUEL USING E FROM 6th COLUMN ABOVE

$h_{Bi} = h_{Bic} + h_{BiE}$

$h_{Bo} = h_{\text{BURNER OUT}} = h_{Di} = h_{\text{DRYER IN}} = h_{Bi} + HV$ Btu/lb mole fuel.

$h_{Do} = h_{\text{Dryer out}} = \sum_{j=1}^{4} h_{ij}(250°F) \cdot N_{ij}$ (ETHALPIES OF INCOMING GAS ONLY)

THEN THE DROP IN ENTHALPY $(h_{Di} - h_{Do})$ IS RELATED TO THE TOTAL HEAT REQUIRED (58.93×10^6) Btu/hr BY

$$\eta = \frac{58.93 \times 10^6 / F}{h_{Di} - h_{Do}}.$$

THE TEMPERATURE OUT OF THE BURNER CAN BE OBTAINED BY THE, ALSO

FM	T°R	h_{N_2}	h_{O_2}	h_{H_2O}	h_{CO_2}	h_{Bi}	$h_{Bo} = h_{Di}$	h_{Do}	η
		Btu/lb mole Fuel							
.286	530					184751			1.022
	710	193175 +	41023 +	14996 +	6039 =			255234	
	1587.4	442885 +	97187 +	35496 +	16750 ≈		592263		
.287	530					178605			.983
	710	186751 +	39318 +	14880 +	6037 =			246985	
	1620.2	437654 +	95282 +	36004 +	17185 ≈		586117		
.288	530					172846			.946
	710	180732 +	37720 +	14771 +	6034 =			239258	
	1652.8	432722 +	93452 +	36557 +	17620 ≈		580358		
.289	530					167441			.912
	710	175082 +	36220 +	14669 +	6031 =			232003	
	1685.3	428082 +	91696 +	37116 +	18055 ≈		574953		
.290	530					162356			.881
	710	169768 +	34809 +	14573 +	6029 =			225179	
	1717.6	423683 +	90001 +	37680 +	18490 ≈			569863	

THESE RESULTS ARE PLOTTED IN FIGURE 1.

FUEL OIL BURNER

A SIMILAR PROCEDURE IS FOLLOWED:

REACTIONS: $C + O_2 \rightarrow CO_2$

$H + \frac{1}{4}O_2 \rightarrow \frac{1}{2}H_2O$

	WT. FRAC*	YIELD N_2	YIELD H_2O	YIELD CO_2	INLET N_2	INLET O_2	INLET H_2O	INLET CO_2
		LB /LB FUEL						
C	.8468	—	—	3.1031	7.4646	2.2563	.0755	.0049
H	.1236	—	1.1046	—	3.2454	.9810	.0328	.0021
OTHER (AS N)	.0296	.0296	—	—	—	—	—	—
LB AIR REQ'D = 14.0742					10.7100	3.2489	.1083	.0070
MOLES AIR REQD = .49					.38228	.10153	.00601	.00016
MOLES EXHAUST		.38334	.06732	.07066				

HEATING VALUE = 17713* Btu/lb. (LHV)

JUST THREE OF THE EQUATIONS FOR DRYER INLET CONDITIONS CHANGE

$N_{CO_2} = .07066F + .0003E$

$N_{N_2} = .38334F + .7809E$

$N_{H_2O} = .06732F + .0123E + 2869.1$

WHERE F IS NOW LB FUEL/HR.

*FROM MARKS HDBK.

THE SOLUTION BY MATRIX INVERSION (HOLLY I):

M-F	DRYER INLET					
H2O	MOLES/LB FUEL					FUEL
EXH	N2	O2	H2O	CO2	EXCESS AIR	LB/HR.
.2700	2.58714	.58313	.10204	.07151	2.82249	2615.5
.2710	2.40925	.53606	.09923	.07144	2.59466	2806.7
.2720	2.25405	.49499	.09679	.07138	2.39589	2998.0
.2730	2.11747	.45885	.09464	.07133	2.22097	3189.3
.2740	1.99634	.42680	.09273	.07128	2.06584	3380.6
.2750	1.88819	.39818	.09103	.07124	1.92732	3571.9
.2760	1.79103	.37247	.08950	.07120	1.80288	3763.2
.2770	1.70326	.34925	.08811	.07117	1.69047	3954.5
.2780	1.62360	.32817	.08686	.07114	1.58844	4145.8
.2790	1.55096	.30895	.08571	.07111	1.49541	4337.2
.2800	1.48445	.29135	.08467	.07108	1.41024	4528.5

THE HEAT BALANCE EQUATIONS ARE

$$h_{BiC} = 1792.9 \text{ Btu/LB FUEL}$$

$$h_{BiE} = 3686.3 \cdot E \text{ Btu/LB FUEL}$$

$$h_{Bo} = h_{Di} = h_{Bi} + LHV$$

$$h_{Do} = \sum_{j=1}^{4} h_{ij}(250) \cdot N_{ij}$$

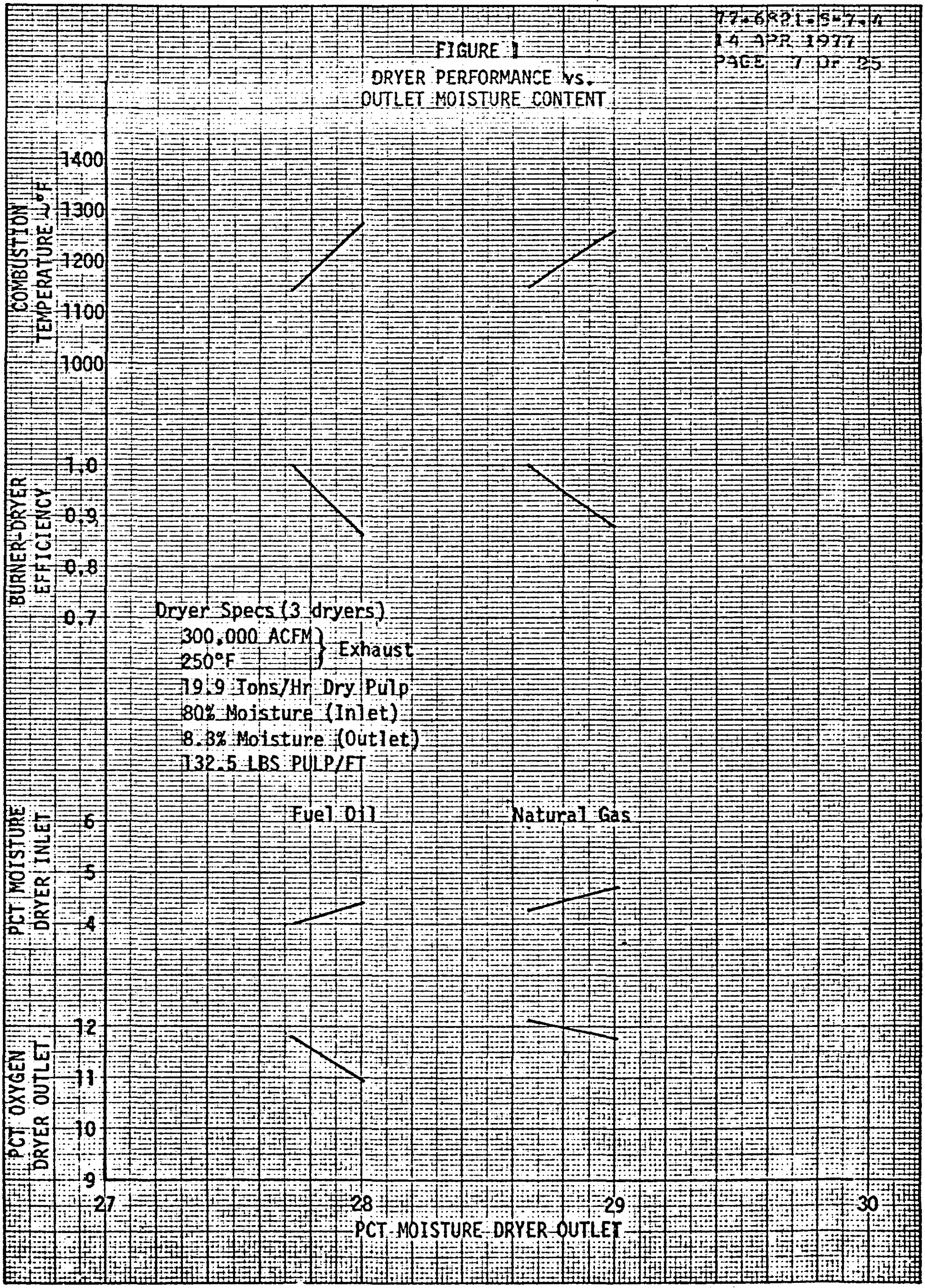
AND THE RESULTS ARE THEN:

		Btu/lb Fuel							
FM	T°R	h_{N_2}	h_{O_2}	h_{H_2O}	h_{CO_2}	h_{Bi}	$h_{Bo} = h_{Di}$	h_{Do}	η
277	530					8024.5			1.014
	710	8404.9 +	1729.1 +	498.4 +	402.1 =			11034.6	
	1591.8	19326.8 +	4109.0 +	1182.2 +	1119.2 ≈		25737.5		
.278	530					7648.4			.958
	710	8011.8 +	1624.8 +	491.4 +	401.9 =			10529.9	
	1638.8	19007.8 +	3987.6 +	1204.4 +	1161.0 ≈		25361.4		
.279	530					7305.4			.909
	710	7653.4 +	1529.6 +	484.9 +	401.8 =			10069.6	
	1685.5	18715.1 +	3872.9 +	1226.9 +	1202.9 ≈		25018.4		
.280	530					6991.5			.864
	710	7325.2 +	1442.5 +	479.0 +	401.6 =			9648.2	
	1731.9	18445.7 +	3764.2 +	1250.2 +	1244.7 ≈		24704.5		

THESE RESULTS ARE ALSO PLOTTED IN FIGURE 1.

CHOICE OF CHARACTERISTICS OF EXISTING DRYERS

AN EXAMINATION OF FIGURE 1 INDICATES THAT THE OUTLET MOISTURE PERCENT STRONGLY AFFECTS THE VARIABLES OF TABLE 1 WHICH AN ATTEMPT IS BEING MADE TO MATCH, VIZ; COMBUSTION TEMPERATURE, WHICH IS DIRECTLY RELATED TO RECYCLING RATIO AND INLET VAPOR OXYGEN. THESE VALUES CAN BE MADE TO APPROACH MORE CLOSELY THE DESIRED VALUES (ESPECIALLY THE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PAGE 7 OF 25
FIGURE 1
DRYER PERFORMANCE vs.
OUTLET MOISTURE CONTENT
COMBUSTION TEMPERATURE °F
1400
1300
1200
1100
1000
BURNER-DRYER EFFICIENCY
1.0
0.9
0.8
0.7
Dryer Specs (3 dryers)
300,000 ACFM
250°F
Exhaust
19.9 Tons/Hr Dry Pulp
80% Moisture (Inlet)
8.3% Moisture (Outlet)
132.5 LBS PULP/FT
Fuel Oil
Natural Gas
PCT MOISTURE DRYER INLET
6
5
4
PCT OXYGEN DRYER OUTLET
12
11
10
9
27
28
29
30
PCT MOISTURE DRYER OUTLET

RECYCLING RATIO), BUT ONLY AT THE EXPENSE OF LOWERED EFFICIENCY UNFORTUNATELY, NO EXISTING EFFICIENCY IS AVAILABLE, BUT IT IS DIFFICULT TO IMAGINE AN EFFICIENCY NOT WELL IN EXCESS OF 90%. THE PRODUCTS OF COMBUSTION ARE USED DIRECTLY FOR COOLING; COMBUSTION SHOULD BE VERY COMPLETE WITH 300-ODD % EXCESS AIR; AND THE ONLY LOSSES ARE SENSIBLE TO THE AMBIENT. NOTE, HOWEVER, THAT THE INLET MOISTURE INCREASES. FURTHERMORE, IF THE CURVES FOR NATURAL GAS WERE EXTENDED TO SAY 1500°F COMBUSTION TEMPERATURE SO THAT RECYCLING 25% EXHAUST WOULD MAINTAIN THE MAXIMUM 1200°F DRYER INLET, THE DRYER INLET MOISTURE WOULD BE ABOUT $.25 \times 30 + .75 \times 5 \approx 11\%$. THIS WOULD INCREASE THE PREDOMINANT PULP TEMPERATURE SOMEWHAT MORE ABOVE THE EXPECTED VALUE THAN IT IS NOW.

IN SUMMARY, WE HAVE NOT BEEN ABLE TO GET A CLOSE MATCH FOR TABLE 1, AND THIS IS BASICALLY BECAUSE

- THE "EXISTING-DRYER" COLUMN IS NOT A SELF-CONSISTENT SET, AND
- LESS IMPORTANTLY, THE SOMEWHAT SIMPLIFIED ANALYSIS AND ASSUMPTIONS WHICH HAVE BEEN USED.

THE "PRESENT-ANALYSIS" DRYER CHARACTERISTICS, AS SHOWN IN TABLE 1 AND FIGURE 2 HAVE BEEN CHOSEN THEN BECAUSE:

- THE EFFICIENCY IS REASONABLE;
- IT IS CONSERVATIVE IN USING DRY AIR (4½ %) (WETTER INLET AIR YIELDS A HIGHER K_3); AND
- IT SIMPLIFIES THE ANALYSIS WITH ZERO RECYCLING.

EVALUATION OF K_2 & K_3

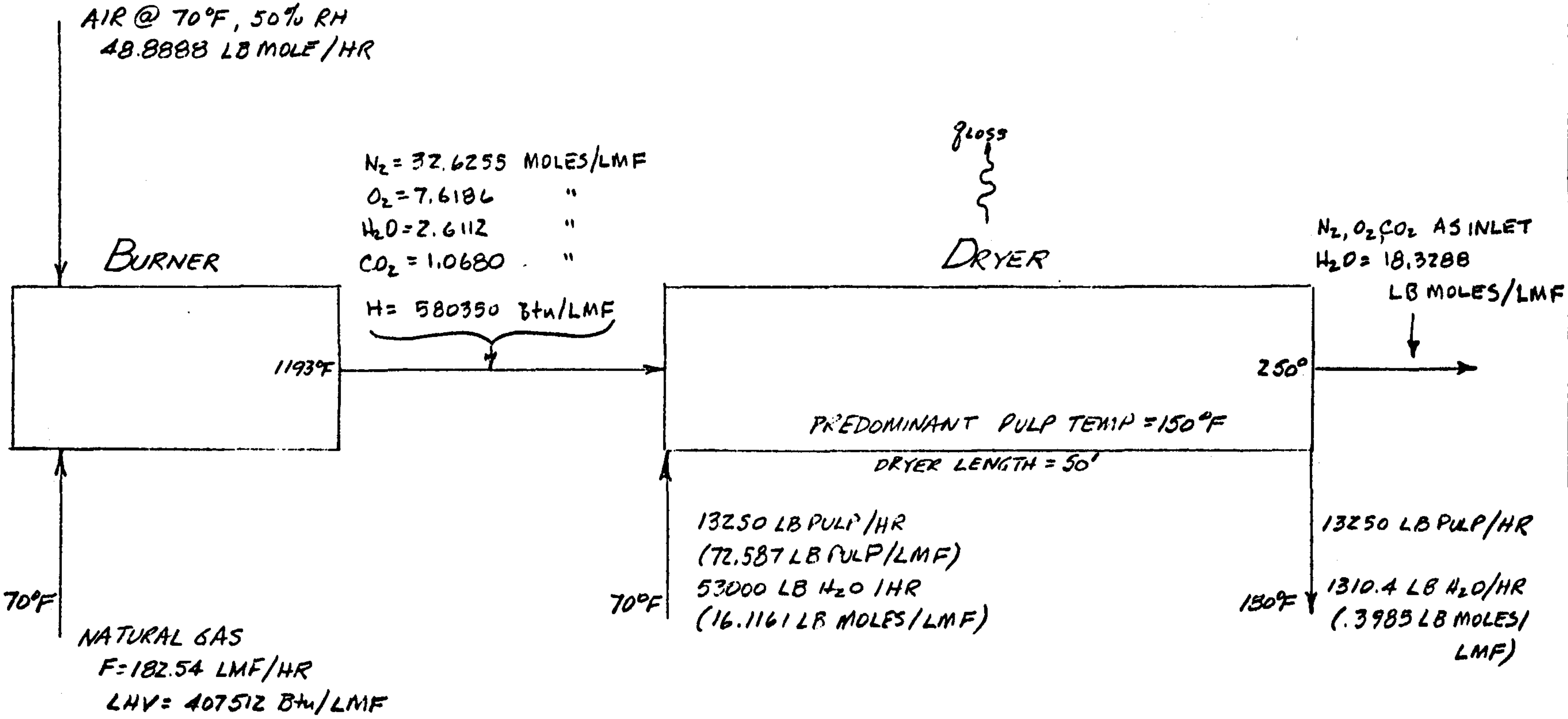
K_2 AND K_3 WERE EVALUATED BY PREPARING A FORWARD DIFFERENCING THERMAL MODEL OF THE DRYER SHOWN IN FIGURE 2. THIS MODEL WAS CODED IN FORTRAN AND THE SOLUTION OBTAINED BY TRIAL AND ERROR.

FOLLOWING IS A LISTING OF THE EQUATIONS USED TO DEVELOP THE MODEL (NOMENCLATURE IS GIVEN IN TABLE 2).

B-10

FIGURE 2

HIGH TEMPERATURE DRYER OPERATING CONDITIONS



AMBIENT PRESSURE = 14.696 PSIA
TEMPERATURE = 70°F

LMF = POUND MOLES FUEL

TABLE 2 NOMENCLATURE

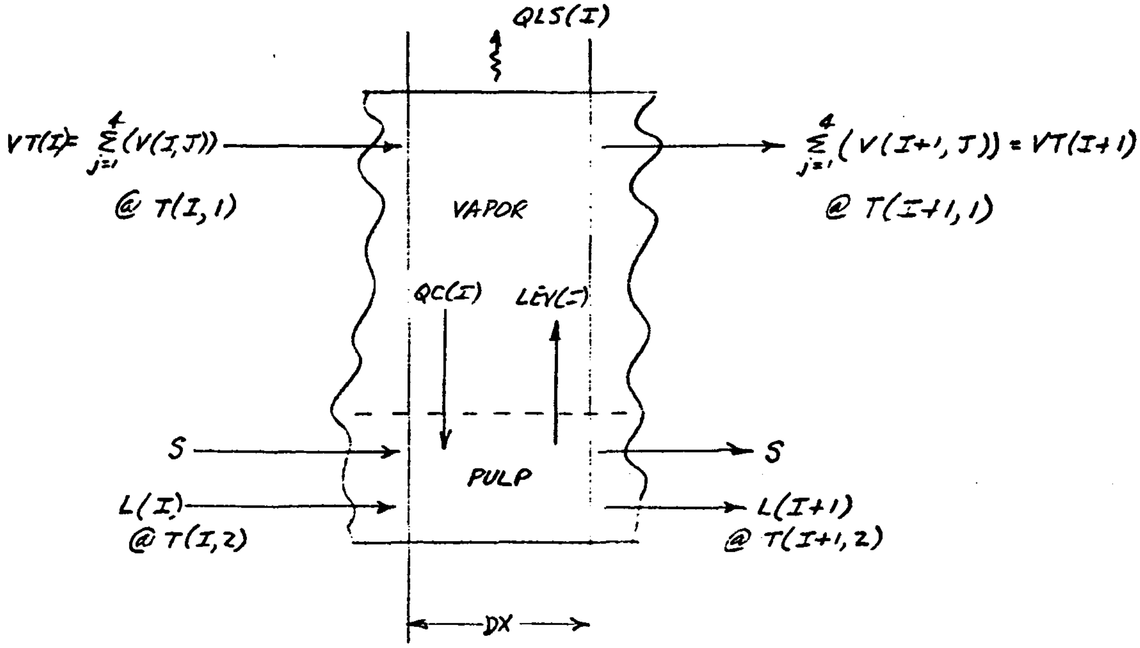
A-D	COEFFICIENTS IN SATURATION PRESSURE EQUATIONS		
A(SS1)-D(SS1)	COEFFICIENTS IN ENTHALPY EQUATIONS		
CPS	SPECIFIC HEAT OF DRY PULP	0.4	Btu/LB.F
CPW	SPECIFIC HEAT OF WATER	18.	Btu/LB MOLE·F
DEV	EVAPORATION COEFFICIENT		LB MOLE/LB PULP-hr-PSI
DX	DRYER LENGTH STEP	0.1	FEET
ENTH(SS1,T)	ENTHALPY OF VAPOR (CURVE FIT FROM TABLES 11, 13, 15, 17, KEENAN & KAYE)		Btu/LB MOLE
FM	MOISTURE FRACTION PULP INLET	0.8	—
F1	FUNCTION IN EQN. 9		
F2	FUNCTION IN EQN. 12		
F3	FUNCTION IN EQN. 16		
FUEL(FEED)	NATURAL GAS FLOW RATE	182.54	LB MOLE/HR
H2O	TOTAL MOLES WATER INLET		LB MOLE/LB MOLE FUEL
* HVIN	VAPOR ENTHALPY INTO DX SEGMENT		Btu/LB MOLE FUEL
HVOUT	VAPOR ENTHALPY LEAVING DX SEGMENT		Btu/LB MOLE FUEL
K1	SYSTEM HEAT LOSS COEFFICIENT		Btu/hr FT F
K2	PULP HEAT TRANSFER COEFFICIENT		Btu/hr-LB PULP-F
K3	PULP EVAPORATION COEFFICIENT		LB MOLE/hr-LB PULP-PSI
L(SS2)	LIQUID WATER IN PULP		LB MOLE/LB MOLE FUEL
LEV(SS2)	LIQUID EVAPORATED		LB MOLE/LB MOLE FUEL
M(SS1)	MOLECULAR WEIGHT		—
MAS	PULP DENSITY IN DRYER		LB PULP/FT (LB MOLE FUEL/HR)
N	EXPONENT IN EQN. 17	4	—
P1(SS2)	PARTIAL PRESSURE WATER VAPOR IN VAPOR		PSI
P2(SS2,T)	VAPOR PRESSURE WATER AT PULP TEMP		PSI
PV(T)	VAPOR PRESSURE FUNCTION (EQN. 12 KEENAN & KEYES)		PSI
PC	CRITICAL PRESSURE OF WATER	3206.2	PSI
PT	TOTAL PRESSURE	14.7	PSI
QC(SS2)	CONVECTIVE HEAT FLOW BETWEEN PULP-VAPOR		Btu/LB-MOLE FUEL
QEV(SS2)	LATENT HEAT OF H2O EXCHANGED PULP-VAPOR (QEV1 = EVAP, QEV2 = COND)		Btu/LB MOLE FUEL
QLS(SS2)	HEAT LOSS FROM SYSTEM		Btu/LB MOLE FUEL
QIN	SLURRY ENTHALPY INTO DX SEGMENT		Btu/LB MOLE FUEL
QOUT	SLURRY ENTHALPY LEAVING DX SEGMENT		Btu/LB MOLE FUEL
QS	SENSIBLE HEAT LOSS IN CONDENSATION		Btu/LB MOLE H_2O
R	RESIDENCE TIME IN DRYER	0.5	hr
S	PULP FLOW RATE	13250/FUEL	LB PULP/LB MOLE FUEL
SL(SS2)	POSITION IN DRYER = ΣDX		FT
SVM(SS2)	SUM OF MASS IN VAPOR EXCLUDING H_2O		LB/LB MOLE FUEL
SVMT(SS2)	SUM OF MASS IN VAPOR		LB/LB MOLE FUEL
TC	CRITICAL TEMP OF WATER	705.4	°F
TO	AMBIENT TEMP.	70	°F
T(SS2,1)	VAPOR TEMP		°F
T(SS2,2)	PULP TEMP		°F
V(SS2,SS1)	MOLES OF CONSTITUENT IN VAPOR		LB MOLES/LB MOLE FUEL

TABLE 2-CONTINUED

VT (SS2)	TOTAL MOLES IN VAPOR STREAM		LB MOLES/LB MOLE FUEL
XL	TOTAL DRYER LENGTH	50	FT
ZETA	COEFFICIENT IN EQN.		—
ZR	ABSOLUTE ZERO	-459.7	°F
* HFG(SS2,T)	HEAT OF VAPORIZATION (CURVE FIT, TABLE I, KEENAN & KEYES)		Btu/LB MOLE
G	FUNCTION IN EQN. 12		—

SS2 POSITION IN DRYER = SL/DX
SS1 VAPOR CONSTITUENT
$1 = H_2O$, $2 = N_2$, $3 = O_2$, $4 = CO_2$

SEGMENT OF DRYER



WE MAY SET UP THE FOLLOWING EQUATIONS:

MASS BALANCES
$$L(I+1) = L(I) - LEV(I) \quad 1.$$
$$V(I+1,1) = V(I,1) + LEV(I) \quad 2.$$

HEAT BALANCES

PULP:
$$QIN(I) = (S \cdot CPS + L(I) \cdot CPW) \cdot T(I,2) \quad 3.$$
$$QOUT(I) = (S \cdot CPS + L(I+1)\,CPW) \cdot T(I+1,2) \quad 4.$$
$$QIN(I) + QC(I) = QOUT(I) + QEV(I) \quad 5.$$

VAPOR
$$HVIN(I) = \sum_{j=1}^{4} V(I,J) \cdot ENTH(J, T(I,1)) \quad 6.$$
$$HVOUT(I) = \sum_{j=1}^{4} V(I+1,J) \cdot ENTH(J, T(I+1,1)) \quad 7.$$
$$HVIN(I) + QEV(I) = HVOUT(I) + QC(I) + QLS(I) \quad 8.$$

IN ADDITION, WE HAVE THE FOLLOWING AUXILIARY EQUATIONS:

- THE HEAT LOSS FROM THE SYSTEM IS ASSUMED TO TAKE PLACE ENTIRELY FROM THE DRYER FOR SIMPLICITY. IT IS EXPRESSED AS

$$QLS(I) = K1 \cdot F1 \cdot DX \cdot (T(I,1) - TO) / FUEL \qquad 9.$$

WHERE $K1$ IS TO BE FOUND
AND $F1 = 1. \qquad 10.$

F1 WAS INCLUDED SO THAT IF IT WERE DETERMINED THAT THE LOSS SHOULD BE A FUNCTION OF TEMPERATURE OR POSITION, IT COULD BE INCLUDED, BUT THIS WAS NOT IMPLEMENTED.

- THE CONVECTIVE HEAT TRANSFER TO THE PULP IS EXPRESSED AS

$$QC(I) = MAS \cdot U \cdot DX \cdot (T(I,1) - T(I,2)) \qquad 11$$

WHERE $U = K2 \cdot F2\,(T(I,1)) \cdot G(I,1) \qquad 12$
$K2$ IS TO BE FOUND
$F2 = 1 + .00055\,(T(I,1) - ZR) \qquad 13.$

AND

$$G = \left(\frac{SVMT(I)}{SVMT(0)}\right)^{.8}. \qquad 14.$$

F2 IS INCLUDED AS AN APPROXIMATE VARIATION OF FACTORS IN THE TURBULENT HEAT TRANSFER EQUATIONS NOT OTHERWISE INCLUDED AND IS INCLUDED THUS FOR SIMPLICITY. G ACCOUNTS FOR THE FACT THAT THE MASS OF VAPOR INCREASES AS I DOES.

- THE RATE OF EVAPORATION IS EXPRESSED AS

$$LEV(I) = MAS \cdot DEV \cdot DX \cdot (P2 - P1) \qquad 15.$$

WHERE $DEV = K3 \cdot F3 \qquad 16.$
$K3$ IS TO BE FOUND
$F3 = 1 - ZETA\left(\frac{S}{L(I)}\right)^{N} \qquad 17.$

F3 HAS BEEN INCLUDED AS A SIMPLIFIED MANNER OF CAUSING THE PULP TEMPERATURE TO RISE AS THE MOISTURE CONTENT DECREASES AS THE SURFACE OF THE PULP DRIES OUT. N=4 WAS USED ALTHOUGH IT IS APPARENT FROM THE RESULTS THAT THAT VALUE IS NOT SATISFACTORY. OBTAINING A BETTER VALUE WAS NOT PURSUED SINCE THE IMPACT ON THE RESULTS IS SMALL.

NOTE THAT IN EQN. 15,

$$P1 = \frac{V(I,1)}{VT(I)}. \qquad 18$$

- THE MASS OF PULP IN THE DRYER IS OBTAINED BY ASSUMING THE PULP TO BE UNIFORMLY DISTRIBUTED OVER THE LENGTH

$$MAS = \frac{S \cdot R}{XL} \qquad 19.$$

- THE VALUE OF QEV DEPENDS ON THE SIGN OF LEV. NOTE THAT AS THE PULP FIRST ENTERS THE DRYER ITS TEMPERATURE IS BELOW THAT OF THE VAPOR DEWPOINT, SINCE THE VAPOR CONTAINS WATER FROM THE COMBUSTION PROCESS. CONDENSATION OCCURS FOR THE FIRST COUPLE FEET. FOR LEV<O

$$QEV2(I) = (QS(I) + HFG(T(I,2)) \cdot LEV(I) \qquad 20$$

WHERE $\quad QS(I) = ENTH(1, T(I,1)) - ENTH(1, T(I,2)), \qquad 21$

SINCE THE CONDENSED STEAM GIVES UP ALL ITS ENERGY TO THE PULP. FOR LEV>O

$$QEV1(I) = HFG(T(I,2)) \cdot LEV(I) \qquad 22$$

SINCE THE PULP MERELY SUPPLIES THE LATENT HEAT.

- THE I=O VALUES ARE OBTAINED FROM THE INITIAL CONDITIONS SHOWN IN FIGURE 2. OTHERWISE IT MAY BE NOTED THAT

$$QOUT(I) = QIN(I+1) \qquad 23$$

AND $\quad HVOUT(I) = HVIN(I+1). \qquad 24.$

T(I+1,1) IS OBTAINED BY A NEWTON-RAPHSON TECHNIQUE ON HVOUT(I).

K1, K2, K3 AND ZETA WERE OBTAINED BY TRIAL AND ERROR. WHILE ALL THESE ARE SOMEWHAT RELATED, THE PROCESS IS EASED BY NOTING THAT PRIMARILY

- K1 AFFECTS THE TOTAL ENERGY QOUT(I)+HVOUT(I) AT I = XL/DX
- K2 AFFECTS THE DISTRIBUTION OF ENERGY $\frac{HVOUT(I) - HVIN(0)}{QIN(0) + HVIN(0)}$ AT I = XL/DX
- K3 AFFECTS THE PREDOMINANT PULP TEMPERATURE LEVEL
- ZETA AFFECTS THE TAIL-END TEMPERATURE RISE.

THE FORTRAN CODING OF THE ABOVE EQUATIONS IS GIVEN IN ATTACHMENT 2.

THE BEST COMBINATION OBTAINED WAS

$K_1 = 139.5$ Btu/hr F ft

$K_2 = 13.95$ Btu/hr F LB PULP

$K_3 = .575$ LB MOLE H_2O/hr psi LB PULP

ZETA = 1.05×10^{-9}

THE RESULTS OBTAINED WITH THESE CALCULATIONS ARE PLOTTED IN FIGURE 3.

LOW TEMPERATURE DRYER PERFORMANCE

HAVING OBTAINED THE PULP-DEPENDENT VALUES OF K_2 & K_3, THE COMPUTER PROGRAM WAS MODIFIED TO MAINTAIN THESE VALUES CONSTANT. IN ADDITION, ZETA WAS SET EQUAL TO ZERO, SINCE ITS EFFECT IS SMALL AND IN CERTAIN INSTANCES YIELDS COMPUTATIONAL PROBLEMS. ALSO K_1 WAS SET EQUAL TO ZERO ON THE BASIS THAT ITS VALUE IS HARD TO IMAGINE ($h = 4.3$ Btu/hr ft^{2}F), AND THE EXACT FORM OF EQN. 9 MAY NOT BE CORRECT. THESE CHANGES WERE FELT TO BE JUSTIFIED DUE TO THE PRELIMINARY NATURE OF THE RESULTS TO BE OBTAINED.

THE PULP INLET CONDITIONS WERE LEFT UNCHANGED, BUT THE VAPOR WAS CHANGED TO BE 70°F, 50% RH AIR HEATED TO A TEMPERATURE OF 250°F, 270°F, OR 290°F. THE QUESTION TO BE INVESTIGATED WAS, THEN, FOR A GIVEN QUANTITY OF AIR (1 LB MOLE/HR) WHAT IS THE RELATIONSHIP BETWEEN THE RESIDENCE TIME AND PULP FLOW SO THAT THE PROPER (9%) EXIT MOISTURE CONTENT IS ATTAINED WITH OTHER OUTLET PROPERTIES FALLING WHERE THEY MAY.

THE RESULTS OF THIS EXERCISE ARE TABULATED IN TABLE 3 AND SOME OF THE RESULTS PLOTTED IN FIGURE 4. FOR THOSE RESULTS NOT NORMALIZED TO AIR FLOW RATE, THE FIGURES HAVE BEEN RATIOED TO AN <u>EXIT</u> AIR FLOW RATE OF 100,000 ACFM SO THAT A DIRECT COMPARISON WITH EXISTING DRYERS IS AVAILABLE. IF THE PULP LOAD IN THE DRYER IS FIXED AT THE PRESENT VALUE OF 132.5 LB/FT, THEN THE CURVES OF FIGURE 5 ARE OBTAINED.

NOTE THAT IN THE COMPUTER PROGRAM, ALL QUANTITIES WERE NORMALIZED TO THE FUEL FLOW RATE. FOR THE LOW-TEMPERATURE

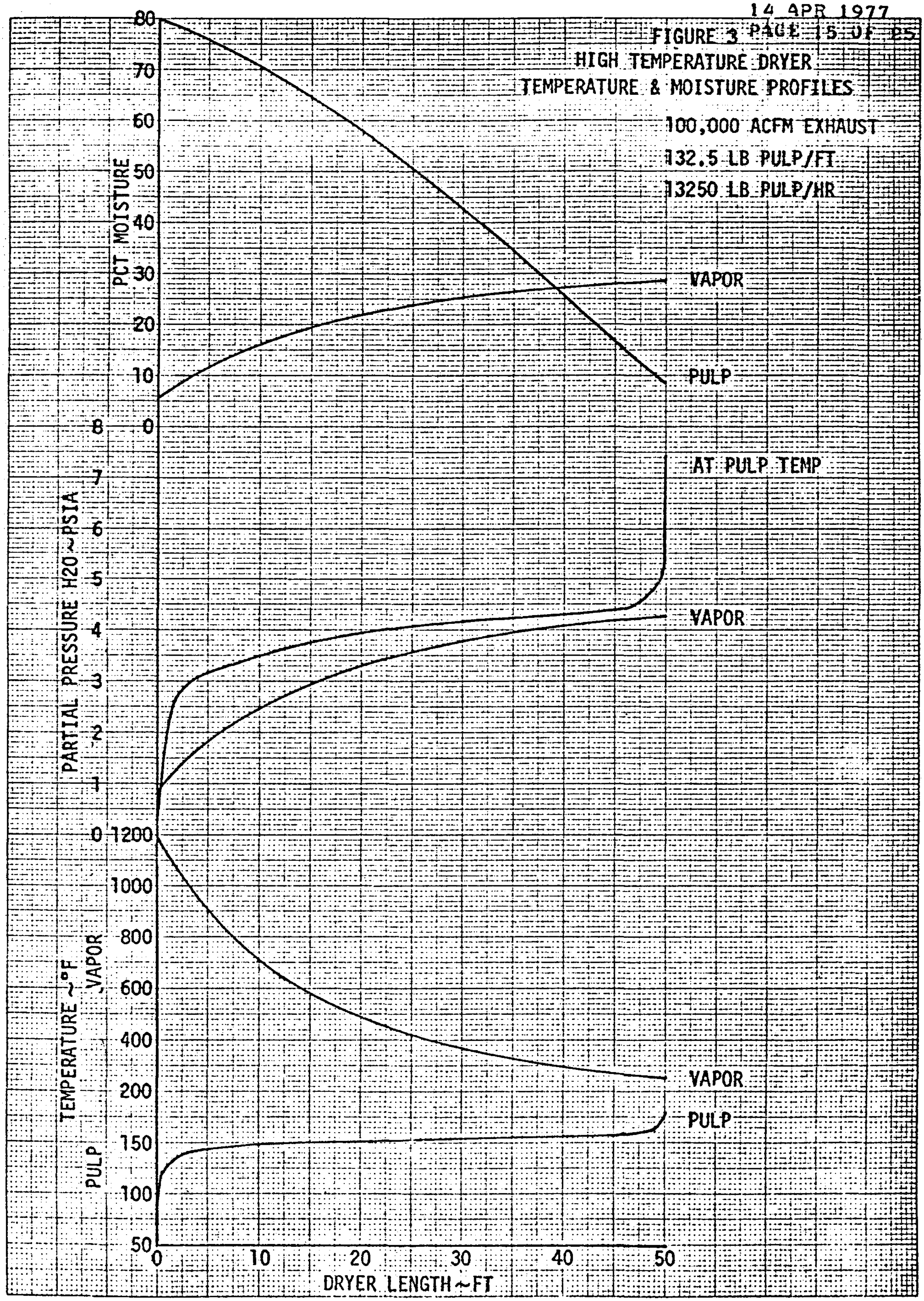


FIGURE 3
HIGH TEMPERATURE DRYER
TEMPERATURE & MOISTURE PROFILES
100,000 ACFM EXHAUST
132.5 LB PULP/FT
13250 LB PULP/HR
PCT MOISTURE
80
70
60
50
40
30
20
10
0
VAPOR
PULP
AT PULP TEMP
VAPOR
PARTIAL PRESSURE H20~PSIA
8
7
6
5
4
3
2
1
0
1200
1000
800
600
400
200
150
100
50
TEMPERATURE ~°F
VAPOR
PULP
VAPOR
PULP
0
10
20
30
40
50
DRYER LENGTH ~ FT

TABLE 4 LOW TEMPERATURE DRYER RESULTS

	RESIDENCE TIME (R)	hr	1.1	1.2	1.3	1.35	1.4	1.5	1.6	1.75	2.0	2.25	2.5	2.7	2.75	2.9
AIR INLET TEMP: 250°F	PULP FLOW (S)	LB/HR-U*			.0201		.04935	.074		.1206	.1528		.1923		.2048	.2108
	NORM. PULP DENSITY (MAS)	LB/FT-U			.0005226		.001393	.00222		.004221	.006112		.009615		.011264	.012226
	VAPOR OUTLET TEMP (T(XL,1))	F			237.35		219.13	203.94		175.61	156.34		133.03		125.73	122.23
	EXIT H_2O VAPOR/AIR IN (V(XL,1))	-			.0167		.0230	.0283		.0384	.0454		.0540		.0561	.0580
	EXIT VOLUME	CUFT/MOLE AIR			511.20		500.93	492.26		475.89	464.57		450.68		446.27	444.15
	FEED (F)	U			11737.		11978.	12189.		12608.	12915.		13313.		13445	13509.
	PULP DENSITY (F·M)	LB/FT			6.13		16.57	27.06		53.22	78.94		128.0		151.4	165.2
	PULP FLOW (F·S)	LB/HR			235.9		591.1	902.0		1520.5	1973.		2560.		2753.	2848.
	PULP EXIT TEMP (T(XL,2))	F			80.93		83.88	86.18		90.15	92.65		95.48		96.33	96.73
	PP H_2O EXIT (P1)	PSI			.2444		.3345	.4095		.5501	.6460		.7620		.7981	.8153
	SAT PRESS AT PULP EXIT (P2)	PSI			.5225		.5749	.6188		.7015	.7584		.8275		.8493	.8598
	ΔP AT EXIT	PSI			.2781		.2404	.2093		.1514	.1124		.0655		.0512	.0445
AIR INLET TEMP = 270°F	PULP FLOW (S)	LB/HR-U		.034			.0955			.1628	.1928		.2291	.2384		
	NORM PULP DEN (MAS)	LB/FT-U		.000816			.002674			.005698	.007712		.011455	.012874		
	VAPOR OUTLET TEMP (T(XL,1))	F		248.54			210.47			169.85	152.09		130.88	126.50		
	EXIT H_2O VAP/AIR IN (V(XL,1))	-		.0194			.0330			.0476	.0541		.0619	0640		
	EXIT VOLUME	CUFT/MOLE AIR		520.78			499.375			475.75	465.20		452.41	449.18		
	FEED (F)	U		11521.			12015.			12612.	12898		13252.	13358.		
	PULP DENSITY (F·M)	LB/FT		9.40			32.13			71.86	99.47		151.92	171.97		
	PULP FLOW (F·S)	LB/HR		391.7			1147.			2053.	2487.		3078.	3185.		
	PULP EXIT TEMP (T(XL,2))	F		84.27			89.67			94.74	96.78		99.09	99.66		
	PP H_2O EXIT (P1)	PSI		.2832			.4753			.6759	.7634		.8669	.8946		
	SAT PRESS AT PULP EXIT (P2)	PSI		.5822			.6910			.8089	.8611		.9235	.9396		
	ΔP AT EXIT	PSI		.2990			.2157			.1330	.0977		.0566	.0450		
AIR INLET TEMP = 290°F	PULP FLOW (S)	LB/HR-U	.0440	.0832		.129			.1824		.233	.2522	.2661			
	NORM PULP DEN (MAS)	LB/FT-U	.000968	.001997		.003483			.005837		.009320	.01135	.013304			
	VAPOR OUTLET TEMP (T(XL,1))	F	262.22	237.87		209.88			177.91		148.24	137.10	129.1			
	EXIT H_2O VAP/AIR IN (V(XL,1))	-	.0218	.0303		.0402			.0517		.0626	.0668	.0698			
	EXIT VOLUME	CUFT/MOLE AIR	532.05	518.39		502.38			483.7		465.98	459.28	454.41			
	FEED (F)	U	11277.	11574.		11943.			12404.		12876.	13064.	13204.			
	PULP DENSITY (F·M)	LB/FT	10.9	23.1		41.6			72.40		120.0	148.3	175.67			
	PULP FLOW (F·S)	LB/HR	496.2	963.0		1541.			2263.		3000.	3295.	3513.			
	PULP EXIT TEMP (T(XL,2))	F	86.98	90.24		93.69			97.32		100.43	101.55	102.33			
	PP H_2O EXIT (P1)	PSI	.317	.438		.575			.731		.876	.931	.970			
	SAT PRESS AT PULP EXIT (P2)	PSI	.635	.704		.783			.875		.962	.994	1.018			
	ΔP AT EXIT	PSI	.318	.266		.208			.144		.086	.063	.048			

*UNSPECIFIED UNITS, MASS/TIME

FIGURE 4

LOW TEMPERATURE DRYER OPERATING CONDITIONS

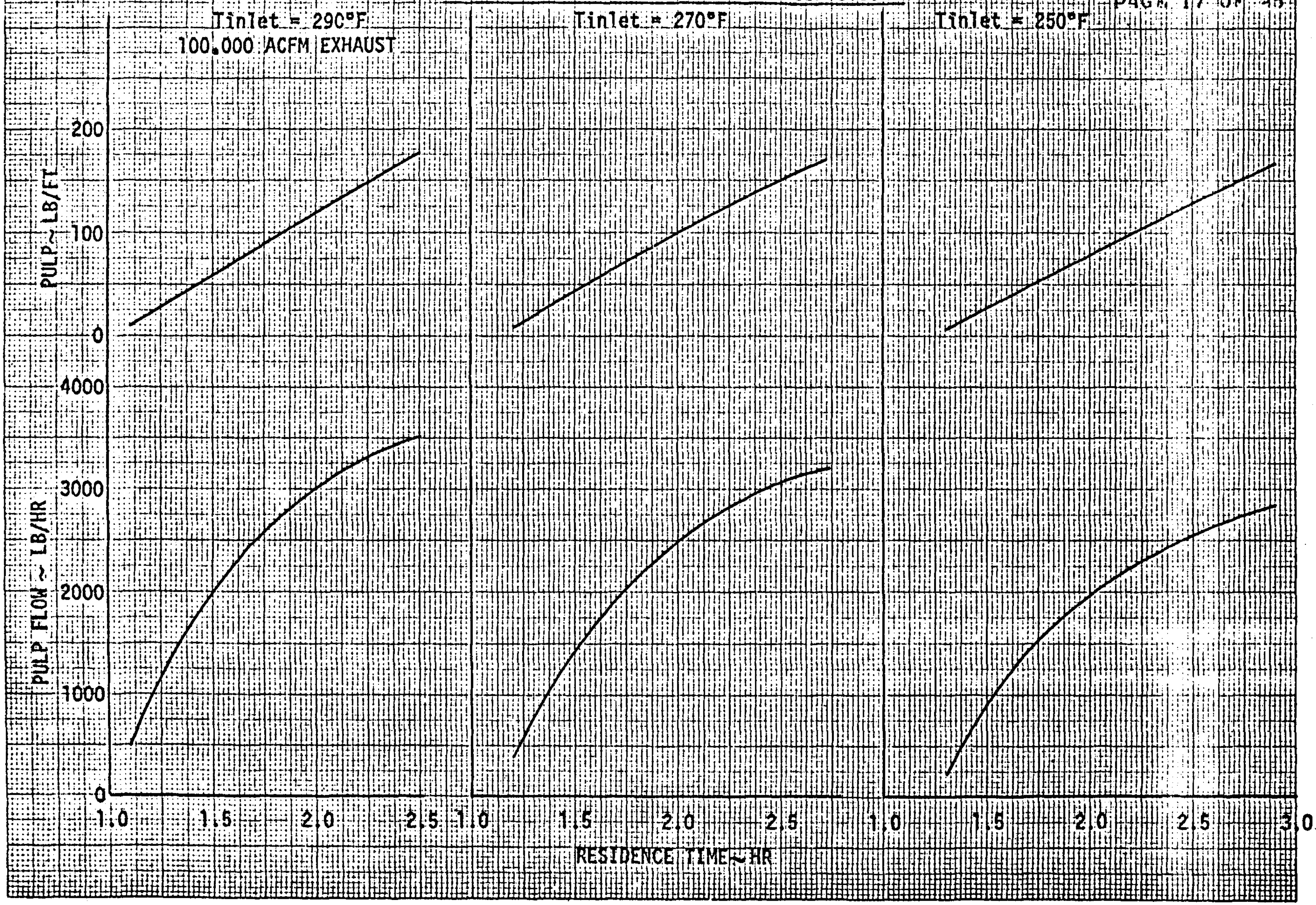
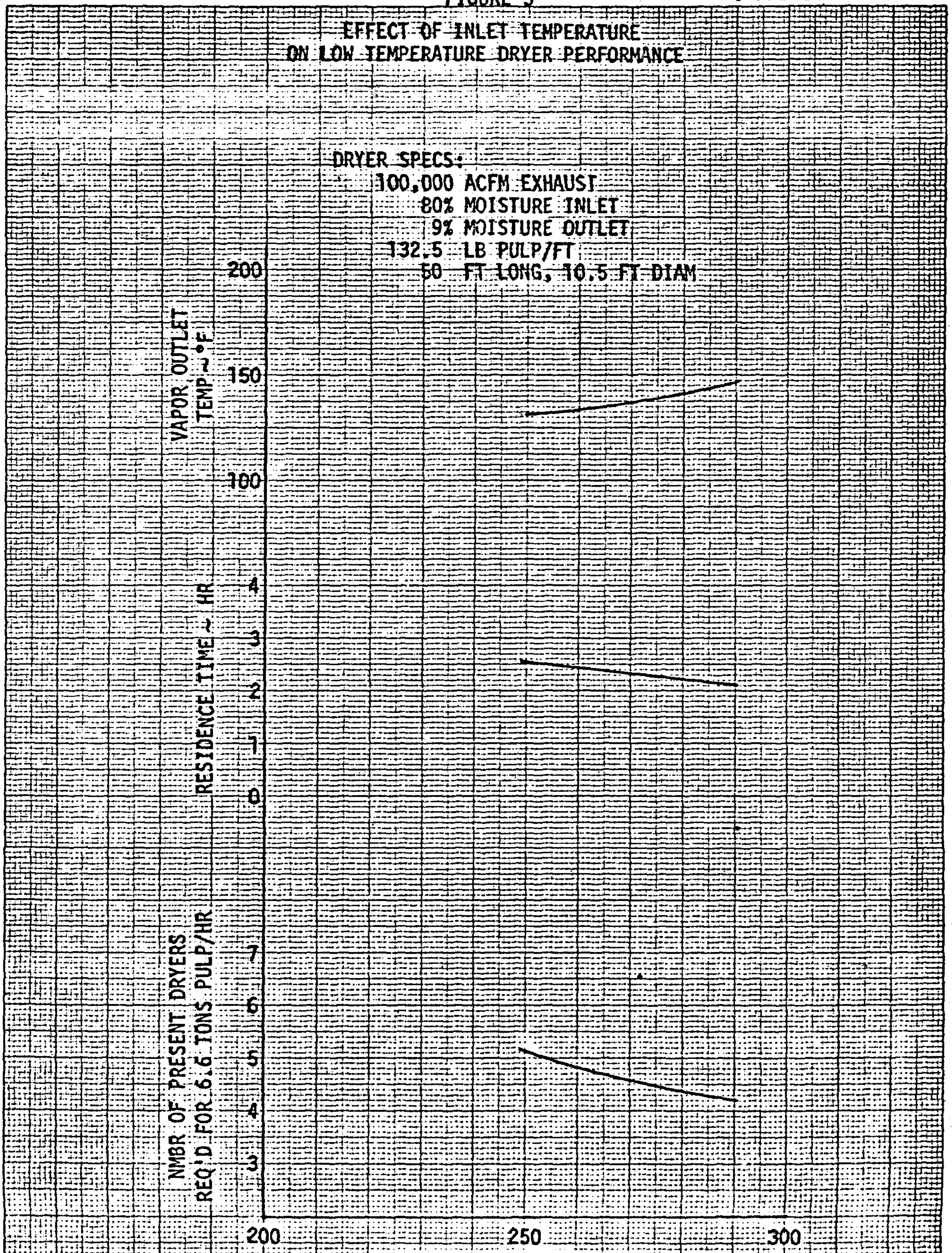


FIGURE 5


EFFECT OF INLET TEMPERATURE
ON LOW TEMPERATURE DRYER PERFORMANCE
DRYER SPECS:
100,000 ACFM EXHAUST
80% MOISTURE INLET
9% MOISTURE OUTLET
132.5 LB PULP/FT
50 FT LONG, 10.5 FT DIAM
VAPOR OUTLET TEMP ~ °F
200
150
100
RESIDENCE TIME ~ HR
4
3
2
1
0
NMBR OF PRESENT DRYERS REQ'D FOR 6.6 TONS PULP/HR
7
6
5
4
3
200
250
300
VAPOR INLET TEMP ~ °F

DRYER EXERCISE, THE "FUEL" IS THE SUBSTANCE WHICH HEATS THE AIR. FOR A GEOTHERMAL APPLICATION, THIS IS WATER. TABLE 4 THEN PRESENTS THE "FUEL" FLOW AND NORMALIZED QUANTITIES AS SOME UNSPECIFIED UNITS (U) OF FLOW REQUIRED TO YIELD THE ASSUMED ONE LB-MOLE HEATED AIR AT THE SPECIFIED TEMPERATURE. THE OPTIMUM VALUE OF U CAN BE DETERMINED SEPARATELY.

THE PRINCIPAL VARIABLE WHICH IS DIFFERENT ASIDE FROM THE PULP FLOW RATE IS THE RESIDENCE TIME IN THE DRYER, WHICH IS EQUAL TO THE DRYER LENGTH DIVIDED BY AVERAGE VELOCITY. THE IMPACT OF THIS CHANGE REMAINS TO BE SEEN.

THE MOISTURE AND TEMPERATURE PROFILES IN THE LOW TEMPERATURE DRYER ARE SHOWN IN FIGURE 6.

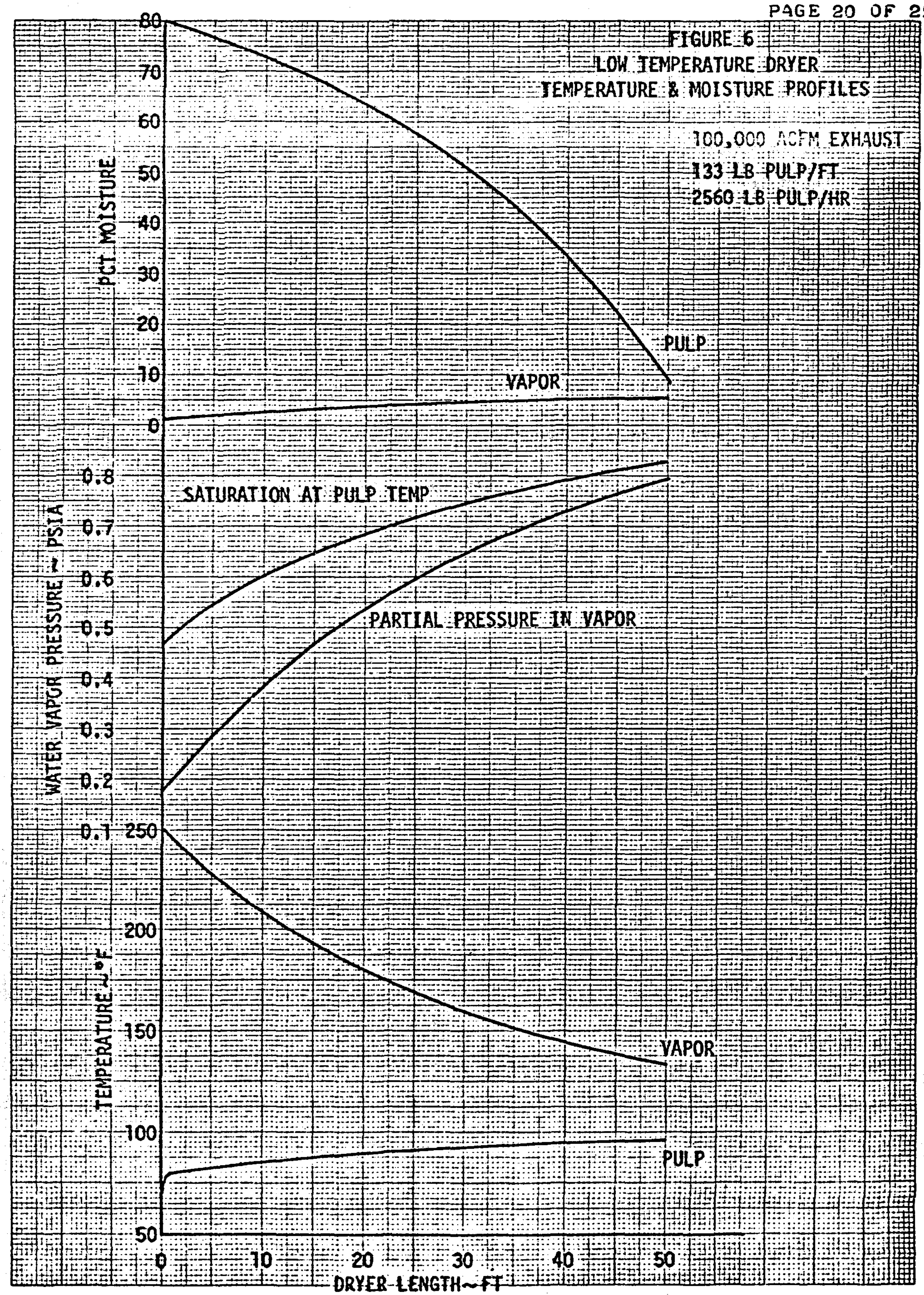


FIGURE 6
LOW TEMPERATURE DRYER
TEMPERATURE & MOISTURE PROFILES
100,000 ACFM EXHAUST
133 LB PULP/FT
2560 LB PULP/HR
PCT MOISTURE
80
70
60
50
40
30
20
10
0
PULP
VAPOR
WATER VAPOR PRESSURE ~ PSIA
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
SATURATION AT PULP TEMP
PARTIAL PRESSURE IN VAPOR
TEMPERATURE ~ °F
250
200
150
100
50
VAPOR
PULP
0
10
20
30
40
50
DRYER LENGTH ~ FT

```
*EVAP                                                              (3/18/71)
      PROGRAM EVAP(INPUT,OUTPUT,TAPE5,TAPE6)
      REAL LEV, L(600), M(4), K1,K2,K3, MAS
*   THE (4) SUBSCRIPTS: 1=H2O, 2=N2, 3=O2, 4=CO2
**  M = MOLECULAR WEIGHTS,   V = LBMOLE/HR/(LBMOLE FUEL/HR)
      DIMENSION T(600,2), V(4), V1(600), SL(600), OB(600),STAR(600)
      NAMELIST /INPUT/ K1,K2,K3,ZETA,N
      DATA M/18.,28.,32.,44./, V/2.61118,36.62553,7.61862,1.06796/
**  K1 = BTU/HR/F/FT,    K2 = BTU/HR/F/LBSOL,    K3 = LBMOLE H2O/LBSOL/HR/PSI
*   H2O CRITICALS: PC = PSI,    TC = F
      DATA K1,K2,K3/119.,12.,0.4/, PC,TC,ZR/3206.182,705.398,459.688/
*   VAPOR PRESSURE COEFFICIENTS A - D
      DATA A,B,C,D/3.2437814,3.2601444E-3,2.0065808E-9,1.215470111E-3/
**  ZETA = (LBMOLE H2O/LBSOL)**N
**  FM = LBH2O/LBPULP AT INLET,   R = RESIDENCE OF SOLID (HOURS)
**  XL = LENGTH OF EVAPORATOR (FEET)
      DATA ZETA,N/1.5E-7,3/, FM,R,XL/0.8,0.5,50./
      DATA ST1,ST2/1H ,1H*/
*   H2O LATENT HEAT CURVE-FIT (BTU/LB)
      HFG(X)= 2485.080 + 3.67149E6/(X-2636.0)
*   KEENAN AND KEYES VAPOR PRESSURE (PSI)
      PV(X)=PC*10.**((X-TC)*(A+B*(TC-X)+C*(TC-X)**3)/(1.+(TC-X)*D)/(X+ZR
+     ))
**  F1 = TEMPERATURE DEPENDENCE OF LOSS HEAT TRANSFER COEFFICINT
**  F2 = VISCOSITY AND CONDUCTIVITY VARIANCE
**  F3 = PULP TEMPERATURE PROFILE AT EXIT
**  G  = REYNOLD≠S NUMBER VARIANCE
      F1(X)= 1.0
      F2(X)= (1. + .00055*(X+ZR))
      F3(X)= (1. - ZETA*(S/X)**N)
      G(X)= ( (X*M(1)+SVM)/SVMT )**0.8
      DXN = 0.10
      V1(1) = V(1)
500   DISPLAY* *
      DISPLAY* *
      DISPLAY* *
      DISPLAY* *
      READ(5,INPUT)
      IF(N.LT.0) GO TO 999
      FUEL = 182.54
      S = 13250./FUEL
      L(1)= S*FM/(1.-FM)/M(1)
```

```
** MAS = LBSOLID/LBMOLE FUEL/(FT/HR)
      MAS=S*R/XL
      V(1) = V1(1)
** VT = LBMOLES/LBMOLE FUEL = CONTENTS OF THE VAPOR STREAM
      VT = V(1)+V(2)+V(3)+V(4)
      TO=T(1,2)=70.
      T(1,1)= 1193.
** H2O = TOTAL LBMOLE H2O/LBMOLE FUEL ENTERING EVAPORATOR
      H2O=L(1)+V(1)
*  TOTAL PRESSURE IS 14.7 PSI
      PT = 14.7
** SVM = LB DRY GAS/LBMOLE FUEL,  SVMT = LB TOTAL GAS/LBMOLE FUEL AT INLET
      SVM = 0.
      DO 1 I=2,4
1     SVM=SVM+V(I)*M(I)
      SVMT = M(1)*V(1) + SVM
      CPS = .40
      CPW = M(1)*1.0
      HVOUT=0.
      DO 4 J=1,4
      CALL ENTH(J,T(1,1),H,CP)
4     HVOUT=HVOUT+V(J)*H
      QOUT = HVOUT + (S*CPS + L(1)*CPW)*T(1,2)
*  FINITE SEGMENT OF DXN(FEET),  PRINT EVERY EVEN FOOT (KPR SEGMENTS)
      DX = DXN
        KPR = INT(1./DX + .0001)
      SL(1)=0.
      DO 20 I=1,600
      IF(SL(I).GT.XL) GO TO 25
      SL(I+1)=SL(I)+DX
      P2 = PV(T(I,2))
** P2 = VAPOR PRESSURE OVER PULP,  P1 = PARTIAL H2O PRESURE OF GAS STREAM
      P1 = V(1)*PT/VT
** DEV = LBMOLE H2O/HR/LBSOLID/PSI = EVAPORATIVE EASE
      DEV = K3*F3(L(I))
** LEV = AMOUNT EVAPORATED OR CONDENSED
      LEV = MAS*DEV*DX*(P2-P1)
      L(I+1) = L(I)-LEV
* WATER CONTENT OF THE PULP STREAM IS NOT PERMITTED BELOW .3 LBMOLE
      IF(L(I+1).LT.0.3) GO TO 25
* ALL WATER LEAVING THE PULP ENTERS THE VAPOR STREAM
      V1(I+1) = H2O-L(I+1)
```

```
* UPDATE TOTAL MOLES
      VT = VT + LEV
** QEV1 = HEAT OF STATE CHANGE RELATIVE TO THE VAPOR
      CALL ENTH(1,T(I,2),H2,CP)
      QEV1 = LEV*H2
      QS = C.
* CHECK FOR CONDENSATION
      IF(LEV.GT.C.) GO TO 5
** QS = SENSIBLE HEAT DROP IN VAPOR BEFORE CONDENSATION OCCURS
        CALL ENTH(1,T(I,1),H1,CF)
        QS = -LEV*(H1-H2)
** QEV2 = HEAT OF STATE CHANGE RELATIVE TO THE PULP
5     QEV2=LEV*M(1)*HFG(T(I,2)) + LEV*CPW*T(I,2)
** QEC = CONVECTIVE HEAT EXCHANGE BETWEEN THE TWO PHASES
      QC= MAS*K2*F2(T(I,1))*G(V(1))*DX*(T(I,1)-T(I,2))
* DETERMINE NEW PULP TEMPERATURE
      T(I+1,2)=-(CEV2-QC-QS-T(I,2)*(S*CPS+L(I)*CPW))/(S*CPS+L(I+1)*CPW)
** QLS = HEAT LOST TO THE SURROUNDINGS
      QLS = K1*F1(T(I,1))*DX*(T(I,1)-TO)/FUEL
****BEGIN SEQUENCE TO DETERMINE NEW VAPOR TEMPERATURE (NEWTON-RAPHSON)
      HVIN = HVOUT
** HVOUT = HVIN+QEV1-QLS-QS-QC
** HBAL = 0 = HVT1-HVOUT
**WHERE HVT1 = SUM[V(I)*H(I,T1)]
**THEN, T(J+1) = T(J) + (0-HBAL)/SUM[V(I)*CP(I)]
      HVOUT = -(QLS+QS+QC-HVIN-CEV1)
      V(1) = V1(I+1)
      DT1 = 10.
**GUESS TOUT = TIN TO START
*AND SET DT1 > 0 ARBITRARILY TO GET PAST STATEMENT 12
      T1 = T(I,1)
12    IF(ABS(DT1).LT.0.1) GO TO 16
      DHBAL = 0.
      HVT1 = 0.
      DO 15 J=1,4
      CALL ENTH(J,T1,H,CP)
      HVT1 = HVT1 + V(J)*H
15    DHBAL = DHBAL + V(J)*CP
      HBAL = HVT1-HVOUT
      DT1 = -HBAL/DHBAL
      T1 = T1 + DT1
      GO TO 12
```

```
*
****END SEQUENCE.    T1 = NEW VAPOR TEMPERATURE
16     T(I+1,1) = T1
       QIN = QOUT
       QOUT = HVOUT + (S*CPS + L(I+1)*CPW)*T(I+1,2)
** QB = 0. FOR NO HEAT LOSSES (K1=0.)
* THE SUM OF ALL QB, WHEN K.NE.C., WILL BE EQUAL TO ALL HEAT LOST
       QB(I)=QIN-QOUT +QEV1-QEV2
       STAR(I) = ST1
       IF(T(I+1,2).LT.T(I,2)) STAR(I)=STF=ST2
20           CONTINUE
25     PRINT 100, SL(I),QB(I),L(I),T(I,2),V1(I),T(I,1),STF
       DISPLAY * HVOUT =*,HVOUT,* T2(300) =*,T(300,2), I
       STF=ST1
       DISPLAY*PRINT?  1=YES,  0=NO*
       ACCEPT IPRNT
       IF(IPRNT.EQ.0) GO TO 500
       WRITE(6,INPUT)
       DO 30 K=1,I
       KCK = ((K-1)/KPR)*KPR
       IF(.N.(KCK.EQ.K-1.O.STAR(K).EQ.ST2.O.K.EQ.I)) GO TO 30
       WRITE(6,100) SL(K),QB(K),L(K),T(K,2),V1(K),T(K,1),STAR(K)
30           CONTINUE
100    FORMAT(F7.2,E12.4,2(F10.4,F8.2),A3)
         GO TO 500
999    STOP
       END
```

```
*ENTH
      SUBROUTINE ENTH(I,TF,H,CP)
*CALCULATES ENTHALPY AND CP FOR GASEOUS H2O,N2,O2, ^ CO2, RESPECTIVELY.
**DHDT = CP FOR NEWTON-RAPHSON ROOT FINDING.
      DIMENSION A(4),B(4),C(4)
      DATA A/-1.198941E7, -2.646506E7, 1.15722, 1.30992/
      DATA B/-93279.3, -130714.4, 522.715, 342.446/
      DATA C/-128.2875, -202.2805, 457.086, 408.538/
*
      T = (TF+459.688)/100.
      GOTO(1,1,3,3)I
1     H = B(I) + A(I)/(T+C(I))
**DHDT = -A/(T+C)/(T+C)/100 = -(H-B)/(T+C)/100
      CP = 0.01*(B(I)-H)/(T+C(I))
      RETURN
3     H = B(I) + C(I)*T**A(I)
**DHDT = A*C*T**(A-1)/100 = A*(C*T**A)/T/100 = A*(H-B)/T/100
      CP = 0.01*(H-B(I))*A(I)/T
      RETURN
      END
```