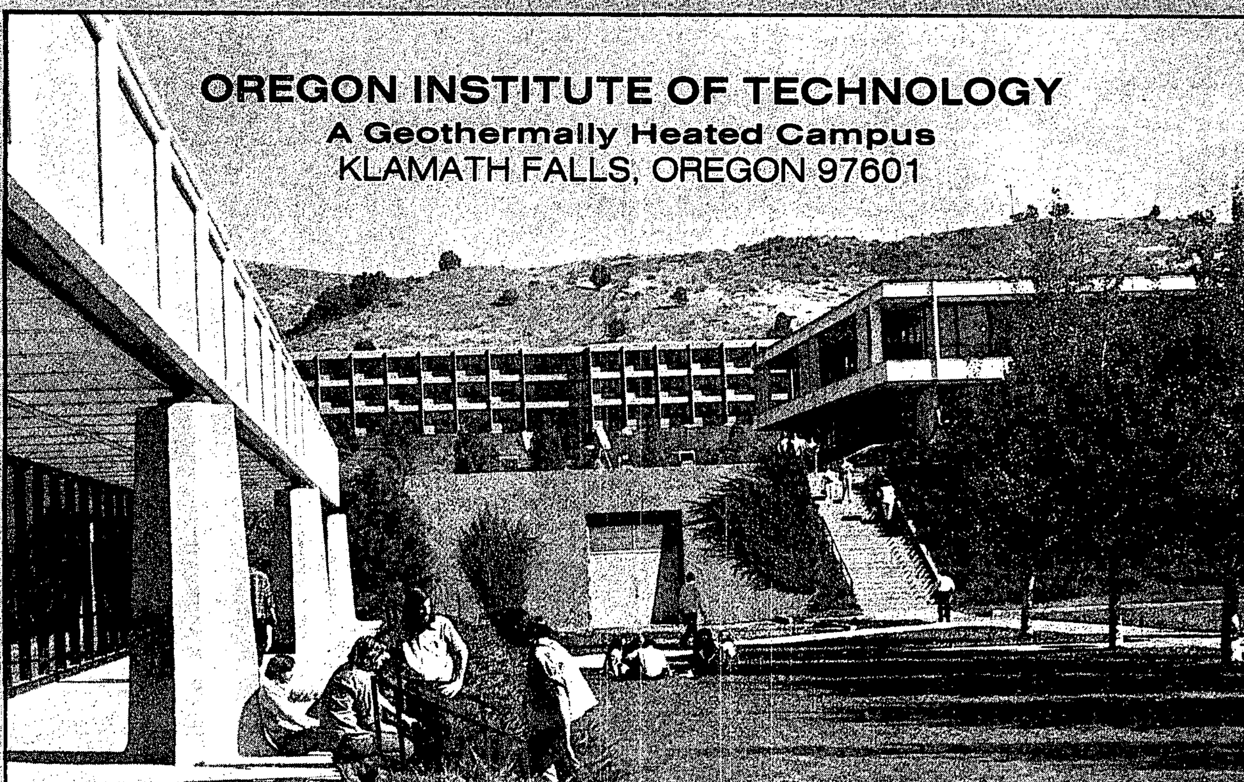
DOE/ET/27256--T

GEO-HEAT CENTER

MASTER



DISCLAIMER

DOE/ET/27256--T

DOE/ET/27256--T17

DE82 015111

GEOTHERMAL RESOURCE UTILIZATION FEASIBILITY STUDY FOR TAD'S ENTERPRISES, INC.

WABUSKA GEOTHERMAL ETHANOL PLANT FINAL REPORT

September 1, 1981

Prepared by Ultrasystems Engineers and Constructors, Inc. for Oregon Institute of Technology, Geo Heat Center, Contract No. TA 21-80.

feg

ULTRASYSTEMS
ENGINEERS AND CONSTRUCTORS
INCORPORATED

September 1, 1981

Mr. Gene Culver
Oregon Institute of Technology
Geo Heat Center
Klamath Falls, Oregon 97601

Subject: Final Report, Professional Services Contract No. TA 21-80

Dear Gene:

Enclosed are three copies of the final report on our study for Tad's Enterprises, Inc. under Professional Services Contract No. TA 21-80, which ends September 3, 1981. We had hoped that the geothermal flash system installation would be completed before the end of the contract period, but completion is still a week or two away. We are thus submitting a final report now in order to meet the contract requirements indicated in Mr. John H. Smith's August 27, 1981, letter to me.

We still intend to keep you posted on the progress at the Wabuska Geothermal Ethanol Plant and we wish to thank you, Gene Ryan, and OIT for supporting this work on behalf of Tad's Enterprises, Inc.

Very truly yours,

R.A. Stenzel

Russell A. Stenzel
Principal Engineer

RAS:sal
Enc: report 3
cc: Neal Townsend w/enc
A. J. Williams no/enc

ULTRASYSTEMS Engineers and Constructors, Inc.
22 SECOND STREET • SAN FRANCISCO, CALIFORNIA 94105 • (415) 777-0636 • TELEX: 69-2356

GEOTHERMAL-RESOURCE-UTILIZATION
FEASIBILITY STUDY FOR
TAD'S ENTERPRISES, INC.
WABUSKA GEOTHERMAL ETHANOL PLANT

FINAL REPORT

Prepared for

Oregon Institute of Technology
Geo Heat Center

Under

Professional Services Contract
No. TA 21-80

Prepared by

Ultrasystems Engineers and Constructors, Inc.
Irvine, California
and San Francisco, California

September 1, 1981

Contents

Figures

Tables

BACKGROUND

Tad's Enterprises, Inc. has a 400,000 gallons per year, 50 gallons per hour, capacity geothermal ethanol plant at Wabuska, Nevada. The plant was designed by L&A Engineering and Equipment, Inc. who also provided much of the equipment. Corn was the planned feedstock material. The plant is in its first year of operation. The plant has one mash preparation tank, eight hatch fermenters, a conventional four-column distillation system, a single-effect evaporator for thin stillage solubles concentration, and a hot water tube-type rotary dryer for DDGS drying.

Geothermal fluid from Wabuska No. 1 well is used for various heating purposes in the plant. Wellhead temperature is about 220°F and the capacity of the existing pump is about 450 gallons per minute. Actual usage is not measured. Geothermal fluid effluent is cooled in a spray pond and used as cooling water in the plant.

The only nongeothermal heated system is the beer stripping column. A 2 million Btu per hour gas/oil fired boiler is used to generate stripping steam. Fuel costs have been on the order of \$2,000 per month or 6 - 10¢ per gallon of product ethanol. The plant has about 200 connected horsepower in electric motors. Electric power is purchased from Sierra Pacific Power. Power costs have been on the order of \$4,000 per month. These two operating costs represent a significant fraction of the alcohol production cost, if feedstock cost is excluded. If either or both operating costs could be reduced through increased geothermal resource utilization, then the profit potential of the plant would be significantly improved.

OBJECTIVE AND SCOPE

The objective of this study was to evaluate the feasibility of increasing the use of the existing geothermal resource. Improvements that would result in costs savings would be recommended for implementation. The scope of work is summarized below:

Task 1 Use of Geothermal Energy in Beer Still Operation

1.1. Determine minimum column pressure drop in the beer still at the design capacity to establish the lowest operable temperature at the still bottom.

1.2. Determine the most suitable way of producing a useable heat source from the geothermal fluid; i.e., steam flashing, which can be directed to the distillation column to produce the azeotrope.

1.3. Determine the suitability of direct geothermal steam injection into the beer still if flashing appears feasible.

1.4. Determine stable operating conditions for the geothermal heat source production and distillation column operation.

1.5. Develop a cascade scheme for use of the geothermal fluid to maximize energy recovery.

Task 2 Generation of Electric Power From Geothermal Resource

2.1. Examine the availability and performance characteristics of small binary cycle power generation units having production capacities in the range of 100 to 200 kW.

2.2. Determine whether binary cycle power production to supply the plant's power needs is attractive with the available 220°F geothermal resource.

SUMMARY

This interim report describes the evaluations made to date under these two work tasks. Results are summarized here.

Task 1

The installation of a geothermal flash system to generate steam for direct injection into the bottom of the beer stripper appears to be technically feasible with some reservations. If the stripper/rectifier system can be operated continuously with no more than a 3.3 psi total pressure drop while maintaining the desired alcohol production rate, then the steam from the flash system should be able to provide all of the heat input required. Installation of a second feed preheater using geothermal fluid is recommended to reduce the stripping steam requirement in the stripper/rectifier system. This beer feed preheater may help to reduce the pressure drop in the stripping column and thus help to keep the total pressure drop in the system low.

The flash system will provide adequate amounts of geothermal effluent at a high enough temperature to satisfy the process heat requirements of downstream users without significant operating changes.

The cost of the proposed system is about $40,000. If use of the boiler can be discontinued entirely, the operating cost savings would result in a payback period of about 1.2 years. The proposed flash system is now being installed. The final report will contain details on installation and start-up experiences.

Task 2

The installation of an organic Rankine cycle power generating facility at the Tad's Enterprises facility is technically feasible, but it may not be practical from an economic standpoint using the presently provided design parameters. This is for several reasons. First, the unit size available (300 kW) only operates at 60% of design capacity making the installed capital cost of the facility very high in relation to the power output (over $2,600/kW). Second, the price at which the power could be sold (just over 5¢ per kWh) does not generate high revenues. Third, due to the current financial climate, a considerable portion of the gross revenues would be required to cover the debt service, unless low interest loans could be secured. Finally, the geothermal effluent temperature (185°F) would be too low to satisfy most of the process heating needs in the ethanol plant, and the effluent would need to be reheated at a high cost.

There are certain incentives that improve the economic outlook such as a 10% investment tax credit and a 10% energy tax credit. However, these credits alone are not sufficient to make this an economically attractive project by itself. An increase in geothermal fluid flow nearer to 700 gpm would increase the output of the generator by 50% with very little additional expenditure for power plant equipment. To accomplish this without affecting the current ethanol plant heating systems, a new well and larger pump would need to be installed. The additional capital cost for this installation would be about $100,000. The new pump would itself consume 60 to 75 kW so the net output would increase only 15 to 20% rather than 50%. Again, the economics would be marginal to unattractive.

TASK 1 - USE OF GEOTHERMAL ENERGY IN BEER STILL OPERATION

Figure 1 is a schematic which illustrates the major process features of the Wabuska plant. It does not accurately represent the as-built facility in the areas of 1) drying, and 2) geothermal fluid piping. The distillation section is sufficiently representative for this discussion. Little design detail was available for the plant.

Current Beer Still Operation - Beer distillation is carried out in two columns; one a stripper and the other a rectifier. Each column is 18" in diameter by about 35' high. The stripping column contains 22 one-pass sieve trays with an 18" tray spacing. Tray hold size is 7/16" diameter. The rectifying column contains about 33 sieve trays (12" spacing) with a smaller hole size, probably ¼" diameter. The stripping section receives an 8 - 10%V alcohol feed from one of the fermenters which is preheated to about 130°F by heat exchange with the condensing overhead vapor stream from the rectifying section. The feed rate is in the range of 500 - 625 gallons per hour.

Heat input for boilup is provided by live steam injection into the stripper sump. About 80 - 90 psig saturated steam is generated in a 2 MM Btu/hr capacity package oil/gas fired boiler. Design steam consumption is about 1,000 lb/hr at the design 198+ proof ethanol production rate of 50 gallons per hour (about 53 - 57 gallons per hour of 190 proof rectifier product). There is no measurement of actual steam consumption.

The steam flow is set by a temperature controller which measures the liquid temperature in the stripper sump. Stripper feed rate is adjusted manually. Rectifier product takeoff rate is set by a rotometer (also by a manual globe valve). The balance of the rectifier overhead product is pumped to the top of the rectifier for reflux. An off-line hydrometer is used to determine the rectifier product quality. Stillage is pumped from

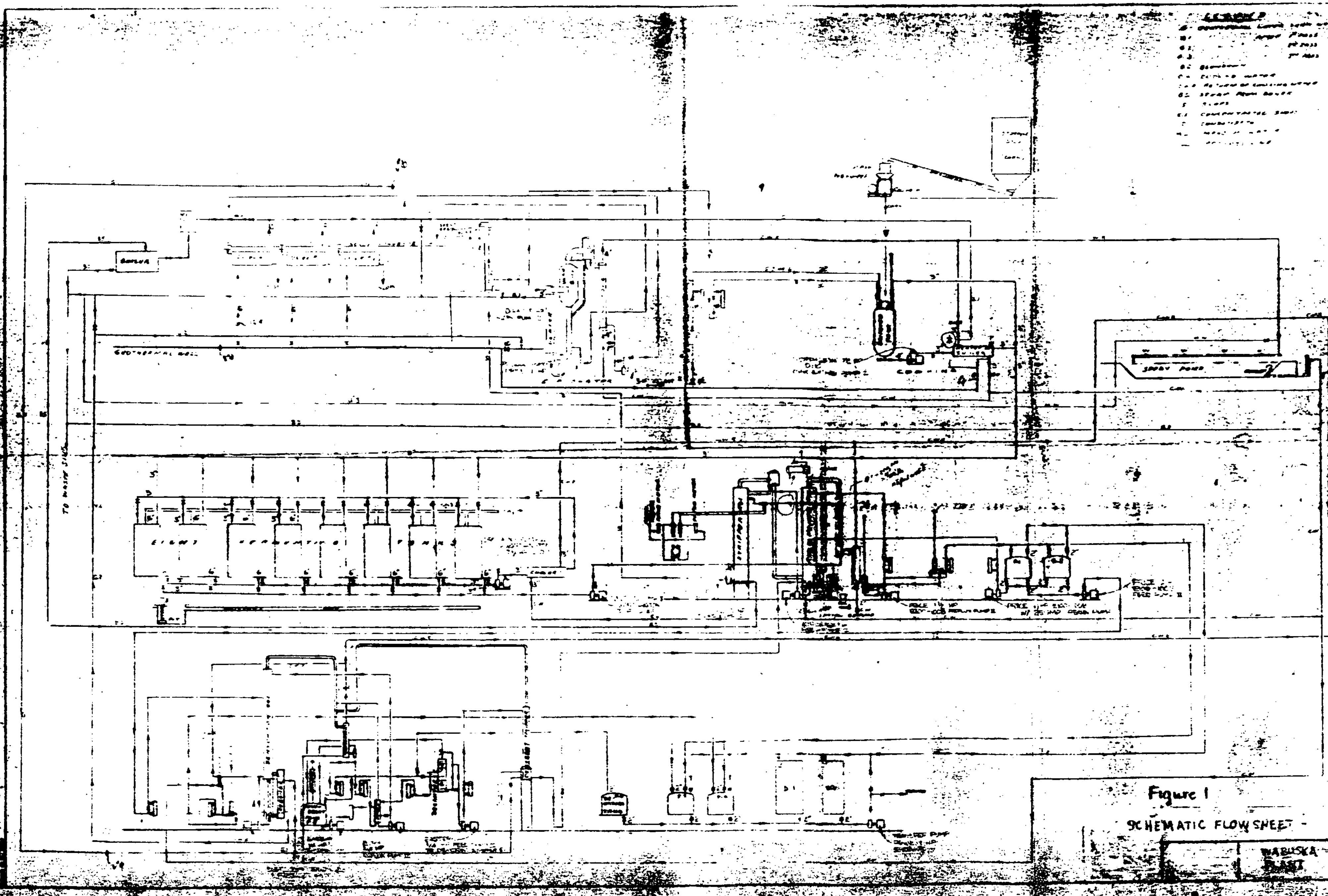


Figure 1

the stripper sump on level control (float-type) to a single effect evaporator. A fusel oil cut is removed from the lower third of the rectifying column.

Typical temperature/pressure conditions were: a 215°F stripper bottoms temperature, a 170°F rectifier overhead temperature, and a 3.7 psia total pressure drop across the two columns. The pressure drop is about the same in each column, and appears to be a bit high for sieve trays columns. The small hole size may partly account for the high pressure drop, especially if plugging occurs.

Production Test at Lower Stripper Bottoms Temperature - A brief test was run to assess the stripping column performance at a lower bottom temperature. The objective was to see whether the column would be operable if low temperature flashed geothermal fluid were available for injection into the stripper sump. With the column in operation under typical flow/temperature/pressure conditions, the temperature controller set point was reduced to 212°F. As the stripper bottoms temperature dropped to 212°F and stablized the total pressure drop decreased to 2.9 psia from 3.8 psia. The rectifier product quality dropped significantly (to less than 160 proof) at about a 60 gallon per hour takeoff rate. This was not unexpected since the temperature controller closed down on the steam control valve reducing the steam input to the stripper. (A rough estimate of 750 lb/hr was determined by crudely measuring the level drop in the boiler feed water tank.) There was not enough heat input to produce an adequate degree of rectification at a 60 gallon per hour product takeoff rate. The beer feed rate to the stripper was then reduced and the rectifier was put on total reflux until the desired overhead quality was reestablished. Product takeoff was initiated at a low rate, and the feed and product takeoff flows were then adjusted to get stable operation at the 212°F bottoms temperature. At stable operation the 190 proof product takeoff rate was about 30 gallons per hour, or about one-half the typical rate. No measurement of stillage alcohol content was made (there was no means of making such a measurement).

The conclusion from this test was that the stripping column will operate satisfactorily at a low bottoms temperature and still produce 190 proof rectifier overhead product - though at a lower rate than desired. What this test could not indicate is whether a higher production rate would be achievable with a higher heat input from low temperature (viz. geothermal) steam versus the restricted input of higher temperature steam in this test. The column designer (L&A Engineering) felt that a bottoms temperature higher than 212°F is required to achieve the desired 60 spb production rate of 190 proof product. There is inherently a minimum pressure drop and, thus, a minimum bottoms temperature below which the desired separation cannot be achieved at the 60 gallon per hour product takeoff rate with the existing columns.

Column Temperature/Pressure Reading Checks - Since temperatures and pressures in the distillation system were obviously critical parameters, a test with boiling water in the stripper sump was run to check the thermocouple readings with the corresponding pressure gage readings in the stripper and rectifier. The plant site is at an elevation of 4,300'. From a plot of elevation versus normal barometric pressure, the normal boiling point of water there would be about 204°F (12.5 psia). A barometer calibrated at the local airport was used to determine the barometric pressure during a temperature reading test check. The stripper sump was filled with cool geothermal fluid and steam from the boiler was injected on temperature control. Column temperatures and pressures were recorded after each incremental increase in the bottoms temperature. A range of 205°F to 216°F was covered. Temperatures in the bottom middle, and top of the rectifier were always higher than the stripper bottoms liquid temperature indicating superheated water vapor was present in the vapor spaces of both columns. The rectifier top pressure was 0 psig throughout. The top temperature ranged from 209.5°F to 209.75°F. The normal boiling point was measured as 203.34°F (corresponding to a pressure of 12.35 psia) with a mercury thermometer in a pan of boiling water. This thermometer was previously used to calibrate all of the thermocouples.

The barometric pressure corrected to sea level ranged from 30.15 to 30.18" of mercury. The Reno airport (4,411' elevation) reported 30.11" of mercury. Actual station pressures at Wabuska and Reno would be about 12.7 psia corresponding to a water boiling point of about 204.8°F. Assuming the gage pressures were correct and an atmospheric pressure of 12.7 psia, all of the stripper bottom thermocouples readings were low - the range was 1.4 to 2.7°F too low. The mercury thermometer placed in boiling water in Oakland read 209.75°F the following day when the actual boiling point should have been very close to 212°F (a new thermometer read 212°F).

It was apparent from this pressure/temperature check that the stripper bottoms temperature indicator was reading low - probably about 2°F. The geothermal fluid supply temperature dial was also reexamined and it appeared to read as high as 222°F.

Historical station pressures at the Reno (Cannon) airport indicated an average station pressure of 25.59" of mercury (12.57 psia) corresponding to a water boiling point temperature of 204.4"F. The highest and lowest recorded pressures were 26.34 in Hg (205.7°F) and 24.65 in Hg (202.5°F).

At a later date Daniels Engineering checked the stripper bottoms pressure with a U-tube water manometer when the system was operating at the design production rate. The bottoms pressure averaged 3.3±0.1 psi above atmospheric pressure. This pressure corresponds to about 15.9 psia or a 216°F water boiling point temperature.

Geothermal Fluid Flash Calculations

If we assume that the stripper bottoms temperature must be 216°F for production of 190 proof alcohol at the design rate, then the stripping steam temperature cannot be lower than this, unless other changes are made to reduce the total column pressure drop and, hence, reduce the stripper bottoms pressure. Even at 216°F there is a potential for generating enough steam from the from the geothermal fluid to operate the stripping column. If the design heat input to the stripper is now supplied by direct injection of 1,000 lb/hr of 100 psia saturated steam which condenses at 216°F, then the enthalpy transferred to the stripper bottoms is about one million Btus per hour. Assuming the beer feed rate averages 555 gallons per hour at 9% volume ethanol, the over 1/3 million Btus per hour are required to heat the water in the stripper bottoms from the 130°F feed temperature to the 216°F bottoms temperature. External preheating of the feed from 130°F to about 190°F, the stripper top temperature, would reduce the required heat input to the stripper bottoms by about 25%. So there is a potential for significantly reducing the present steam injection rate in the stripping column.

The geothermal well turbine pump is capable of delivering about 450 gpm of 220 - 222°F geothermal fluid to the alcohol plant at about 30 psig. Using the thermodynamic properties of water, we calculated theoretical steam production rates at various flash temperatures for both 220°F and 222°F geothermal fluid temperatures using:

$$F_o h_{f_o} = S_1 h_{g_1} + L_1 h_{f_1}$$

where F_o = feed supply rate in lb/hr $\cong$ 450 gpm x 60 x $\dfrac{59.6 \text{ lb/cf}}{7.48 \text{ gal/cf}}$

= 215,130 lb/hr

h_{f_o} = saturated liquid enthalpy of feed, Btu/lb at supply temperature to

S_1 = steam production rate, lb/hr at flash temperature T_1

h_{g_1} = saturated vapor enthalpy, Btu/lb at flash temperature T_1

L_1 = residual fluid rate, lb/hr at flash temperature T_1 $(= F_o - S_1)$

h_{f_1} = saturated liquid enthalpy of residual fluid at flash temperature T_1

$h_{f_{g1}}$ = enthalpy of evaporation at $T_1 = h_{g1} - h_{f_1}$, Btu/lb

For a 222°F supply temperature (T_o), the following results were calculated:

T_1, °F	S_1, lb/hr	S_1h_{fg1}, Btu/hr	P_1', psig*	P_1, psia
222	0	0	5.27	17.87
218	890	860,000	3.95	16.55
216	1,330	1,290,000	3.3	15.90
214	1,775	1,720,000	2.68	15.28
204.5	3,890	3,790,000	0	12.6

For a 220°F supply temperature (T_o), the following were determined:

T_1, °F	S_1, lb/hr	S_1h_{fg1}, Btu/hr	P_1', psig*	P_1, psia
220	0	0	4.59	17.19
218	448	433,000	3.95	16.55
216	895	866,000	3.3	15.90
214	1,340	1,300,000	2.68	15.28
212	1,785	1,734,000	2.1	14.7
204.5	3,445	3,360,000	0	12.6

If the supply temperature is as high as 222°F, there should be sufficient steam available at 216°F to operate the stripper at the design production rate. If the supply temperature is only 220°F, then the steam rate at 216°F is marginal without additional feed preheating or without some other change which would reduce the pressure drop and temperature in the stripper.

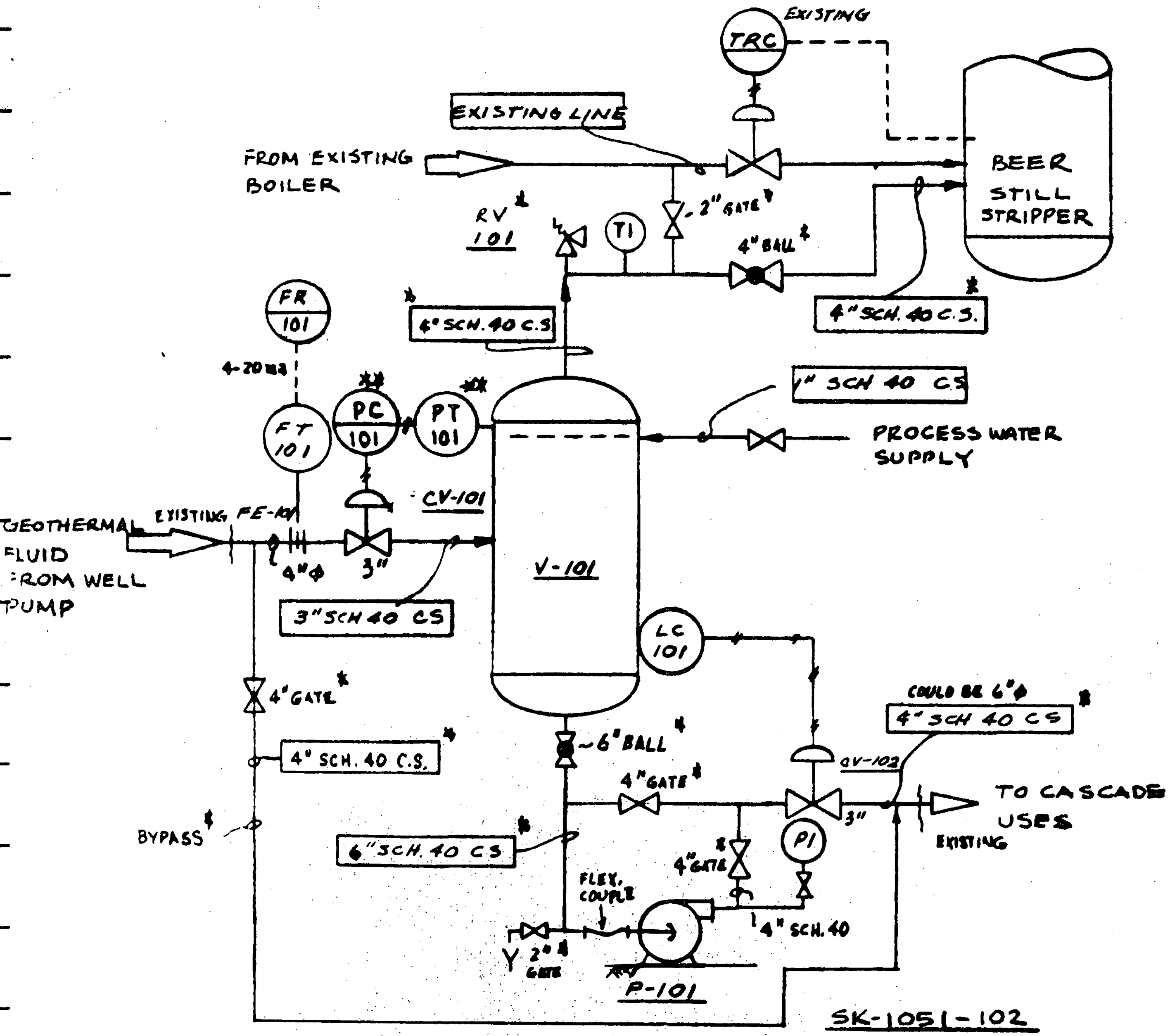
Flash System Proposed

A geothermal fluid flashing system was designed for the Wabuska plant. Figure 2 is a flow diagram of the proposed flash system. All of the geothermal fluid supply would be piped to the flash system, and all geothermal fluid users would then be supplied with a lower temperature residual fluid from the flash vessel. The flash vessel itself would be 3' diameter by 6' high with a York-type demister as indicated in Figure 3.

A flow recorder (FR-101) was included to measure the geothermal fluid flow rate into the flash system. Currently there is no way to measure geothermal flows in any part of the system.

*Assumed average atmospheric pressure = 12.6 psia.

ultrasystems



SK-1051-102
GEOTHERMAL FLASHER
P&ID
TAD'S ENTERPRISES, INC

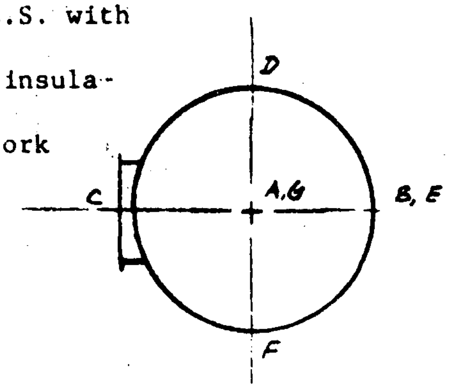
* REVISIONS △1
** REVISION △2

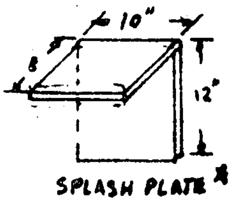
Figure 2

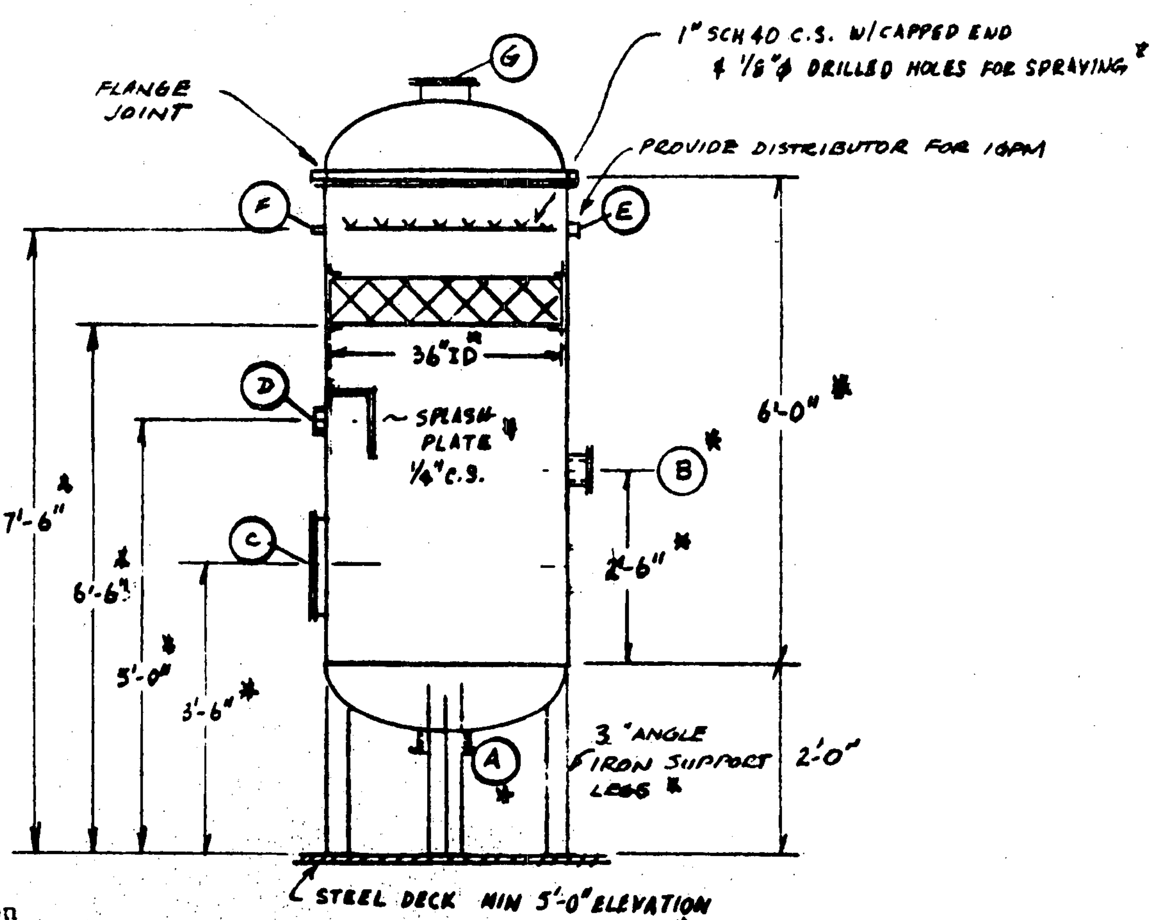
REV. △1
REV △2

Notes

1. Design pressure: 50 psig at 250°F
2. Operating pressure: 5 psig at 215°F
3. Material of construction: C.S. with 1/8" corrosion allowance
4. Provide support lugs for 2" insulation
5. Mesh mist eliminator 304SS York style 431 or equal 6" thick







Nozzle Schedule

No.	Size	Connection
* A	6"	weld neck flange joint (LIQ. OUTLET)
* B	4"	weld neck flange joint (LC-101)
C	12"	weld neck flange joint with blind (HAND HOLE)
D	4"	screw (LIQUID INLET)
E	2"	screw (WASH WATER INLET)
F	1"	screw (PRESS. TAP FOR PC-101)
G	6"	weld neck flange joint (VAPOR OUTLET)

* REVISIONS △

SK-1051-101

GEOTHERMAL FLASH VESSEL

TAD'S ENTERPRISES, INC

Figure 3

REV △

A pressure controller (PC-101) would be used to maintain the desired pressure in the flash vessel vapor space by controlling the geothermal fluid feed rate into the vessel. Flashed fluid would be injected into the stripper bottoms. Residual fluid would be pumped (P-101) out of the bottom of the flash vessel on level control (LC-101) and supplied at about 30 psig to the downstream users.

The existing TRC would be used to monitor the stripper bottoms liquid temperature. The bottoms temperature would be used as a guide for increasing or decreasing the set point pressure for the flash system. The current steam boiler system would be maintained on a standby basis to 1) provide a small amount of supplemental stripping steam if needed, or 2) provide all of the stripping steam if the flash system is out of service.

Table 1 summarizes the major equipment and instrument specifications for the flash system.

TABLE 1

GEOTHERMAL FLASH SYSTEM SPECIFICATIONS

Tag No.	Description
FE-101	Geothermal Feed Flow Element - 4" orifice plate w/o flanges, 500 gpm, 316SS
FT-101	Geothermal Feed Flow Transmitter - Fisher No. 1151 D/P cell, 0-250" range, 4-20 ma output, 316SS diaphragm
FR-101	Geothermal Feed Flow Recorder - Fisher RD-222 strip recorder, 1 pen, 0-500 gpm Pinear scale
LC-101	Flash Vessel Level Controller - Masoneilan No. 12804 displacer type transmitter/controller, side-mounted with 14" range, 3-15 psi output, 316SS displacer tube
CV-102	Flash Vessel Level Control Valve - 3" Camflex II valve No. 35-35102, 300# C.S. body with 6" spring diaphragm actuator
PIC-101	Flash Vessel Pressure Controller - Masoneilan No. 2716, 316SS bellows type element, 0-15 psig range, proportional plus reset, 3-15 psi output
PT-101	Flash Vessel Pressure Transmitter - Fisher No. 1151 D/P cell, 0-750" range, 3-15 psi output, 316SS diaphragm
CV-101	Geothermal Flash Control Valve - 3" Camflex II valve No. 35-35102, 300# body (316SS) with 6" spring diaphragm actuator
RV-101	Pressure Relief Valve - 1¼" 1543G, G orifice, 50 psig set pressure, bronze
P-101	Geothermal Fluid Pump - Goulds Model 3196MT, 3 x 4-13 with 10" open impeller (316SS), 450 gpm @ 104' TDH, D.I case; 20 HP, 1,750 rpm, 230/460V, 3 ϕ 60 Hz explosion proof motor

TABLE 1 (cont'd)

Tag No.	Description
V-101	Geothermal Flash Vessel - 3'-0" ID x 6'T·T C.S. Shell with ASME 2:1 S.E. heads, 50 psig pressure
X-101	Flash Vessel Demister - York style 431, 36" IDX 6" thick with top and bottom grids, 304SS

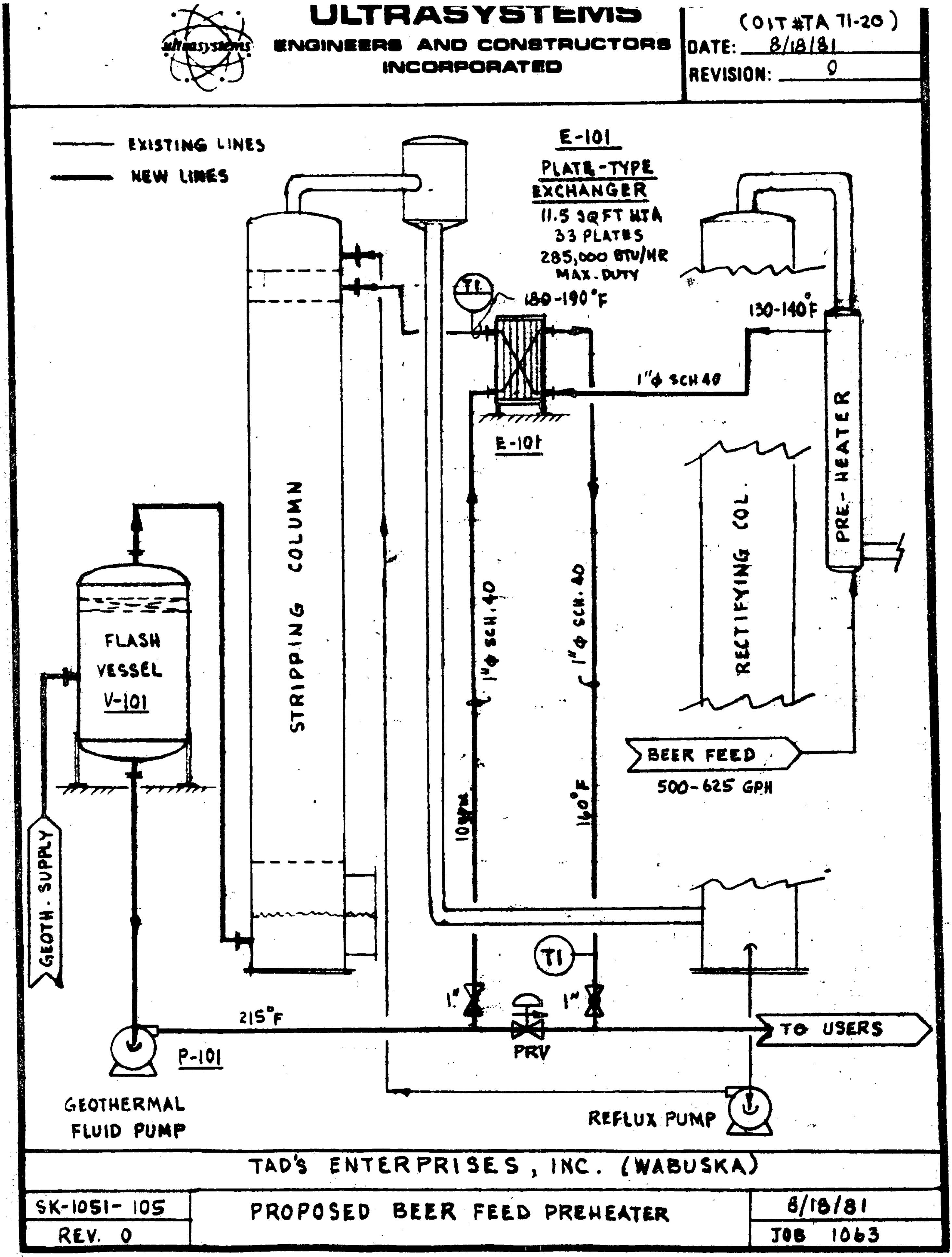

ULTRASYSTEMS
ENGINEERS AND CONSTRUCTORS
INCORPORATED
(OIT #TA 71-20)
DATE: 8/18/81
REVISION: 0
EXISTING LINES
NEW LINES
E-101
PLATE-TYPE
EXCHANGER
11.5 SQ FT HTA
33 PLATES
285,000 BTU/HR
MAX. DUTY
TI
180-190°F
130-140°F
1"ϕ SCH 40
E-101
PRE-HEATER
RECTIFYING COL.
STRIPPING COLUMN
FLASH
VESSEL
V-101
1"ϕ SCH. 40
1"ϕ SCH. 40
BEER FEED
500-625 GPH
GEOTH. SUPPLY
160°F
TI
215°F
1"
1"
PRV
TO USERS
P-101
GEOTHERMAL
FLUID PUMP
REFLUX PUMP
TAD'S ENTERPRISES, INC. (WABUSKA)
SK-1051-105
REV. 0
PROPOSED BEER FEED PREHEATER
8/18/81
JOB 1063

Figure 4

If the proposed flash system is implemented it will top about 6°F from the 220 to 222°F supply temperature. All present users would then be supplied with cascaded fluid. Figure 5 shows the proposed system. A new supply line would be run to the new flash vessel in the distillation area. Residual fluid from the flash system would be piped into the current 6" supply header upstream of the takeoffs to the dehydration column reboiler and the stillage evaporator. The fluid would then go into the building through the existing 6" line (flow reversed from present) to supply users in the building. The flash evaporator could use twice cascaded fluid. The dehydration column reboiler could also be repiped so that geothermal fluid would enter the reboiler from the bottom rather than the top (cocurrent rather than countercurrent flow).

The combined geothermal reject will still have a fairly high temperature. A low to moderate temperature use, such as greenhouse heating, could extract useful heat from reject geothermal fluid. The geothermal well is thought to be capable of 800 - 900 gpm production if a larger turbine pump were installed in the present well casing. There is thus the potential for supplying all the process heat for a 400,000 gallon per year ethanol plant expansion.

Economics of the Proposed System

Capital and operating and maintenance costs for the flash system and the beer feed preheater have been estimated as indicated below.

Capital Cost Items:

• Flash system equipment and instruments (FOB factory)	\$15,000
• Preheater (FOB factory)	2,000
• Delivery, installation, and startup costs (includes piping, valves, insulation, supports and labor)	17,000
• Engineering costs	5,000
Total capital investment (TCI)	\$39,000

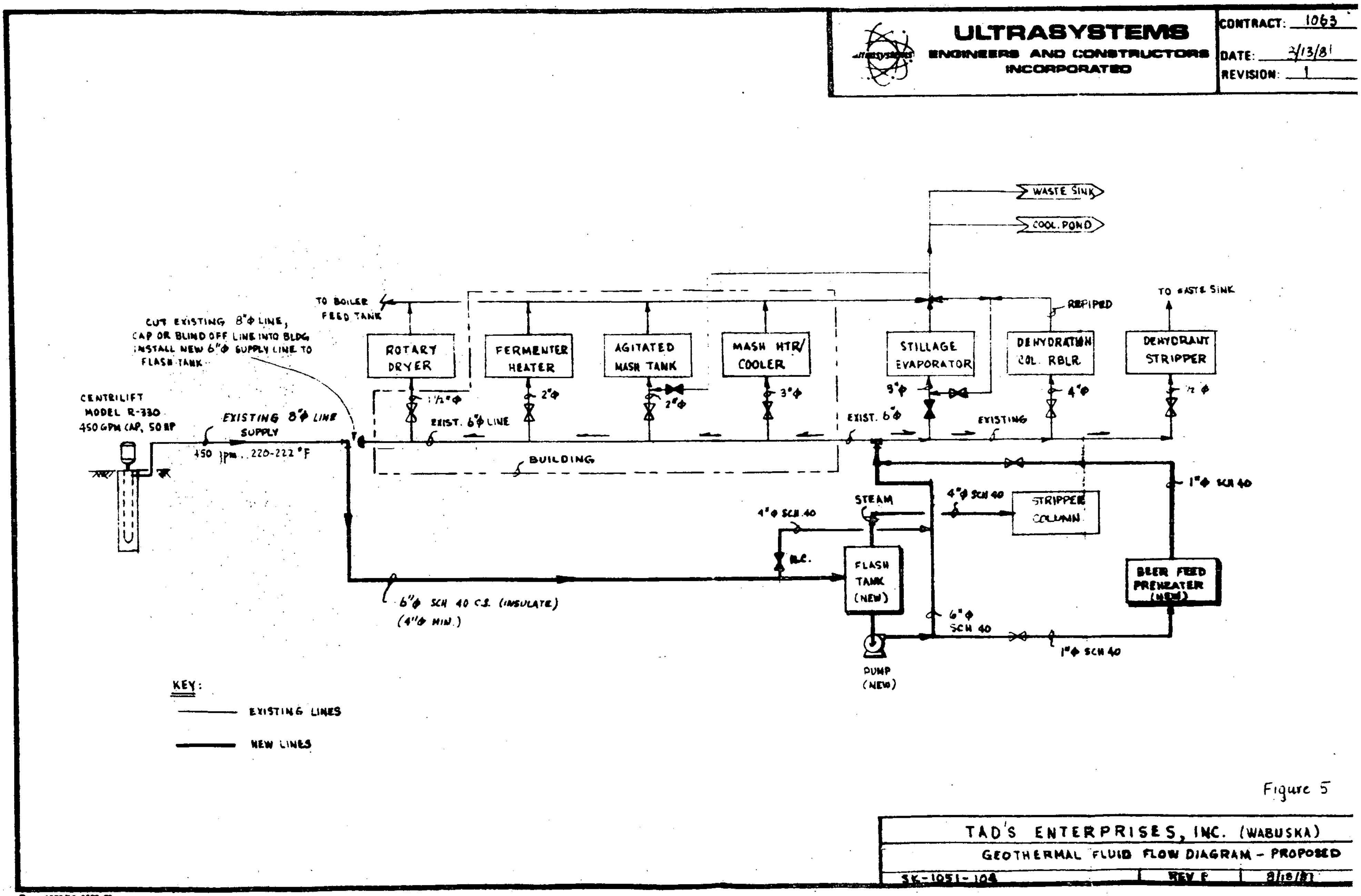

ULTRASYSTEMS
ENGINEERS AND CONSTRUCTORS
INCORPORATED
CONTRACT: 1063
DATE: 3/13/81
REVISION: 1
WASTE SINK
COOL. POND
TO BOILER FEED TANK
TO WASTE SINK
REPIPED
CUT EXISTING 8"Φ LINE, CAP OR BLIND OFF LINE INTO BLDG INSTALL NEW 6"Φ SUPPLY LINE TO FLASH TANK
ROTARY DRYER
FERMENTER HEATER
AGITATED MASH TANK
MASH HTR/ COOLER
STILLAGE EVAPORATOR
DEHYDRATION COL. RBLR
DEHYDRANT STRIPPER
1½"Φ
2"Φ
2"Φ
3"Φ
3"Φ
4"Φ
½"Φ
CENTRILIFT MODEL R-330 450 GPM CAP, 50 HP
EXISTING 8"Φ LINE SUPPLY
450 gpm, 220-222°F
EXIST. 6"Φ LINE
EXIST. 6"Φ
EXISTING
BUILDING
STEAM
4"Φ SCH 40
4"Φ SCH 40
STRIPPER COLUMN
1"Φ SCH 40
FLASH TANK (NEW)
BEER FEED PREHEATER (NEW)
6"Φ SCH 40 C.S. (INSULATE) (4"Φ MIN.)
6"Φ SCH 40
1"Φ SCH 40
PUMP (NEW)
KEY:
EXISTING LINES
NEW LINES
TAD'S ENTERPRISES, INC. (WABUSKA)
GEOTHERMAL FLUID FLOW DIAGRAM - PROPOSED
SK-1051-104
REV F

Figure 5

Annual Operating and Maintenance Costs (Savings):

• Boiler fuel ($2,000/month - 11 months/yr)	($44,000)
• Electric power (13 kwh/hr x 7,920 hr/yr x 5.45¢/kwh)	5,600
• Operating labor (1 hr/day x 336 days/yr x $10/hr)	3,300
• Maintenance materials and labor (5% of TCI)	2,000
Total Annual O&M Costs	($33,100)

$$\text{Payout period} = \frac{\$39,000}{\$33,100/\text{yr}} \cong 1.2 \text{ years}$$

A simple calculation indicates a quite short payout period if the system can completely replace the boiler as a steam source.

Conclusions

The Task 1 preliminary evaluation appeared sufficiently encouraging to Mr. Townsend of Tad's Enterprises, Inc. so that he is proceeding with implementation. It is hoped that installation of the flash system will be completed in a few weeks and that some preliminary operating experience can be included in the final report.

TASK 2 - GENERATION OF ELECTRIC POWER FROM THE GEOTHERMAL RESOURCE

Background

Although there are several manufacturers who market organic Rankine cycle (ORC) energy recovery systems, only one manufacturer could be located who had a standard offering in the size and temperature range of this project. This manufacturer is Ormat Turbines, Ltd. from Israel, who is represented in the United States by Whiting Corporation in Harvey, Illinois. Ormat manufactures a skid mounted 300 KW ORC system that is capable of energy recovery from waste heat streams with temperatures as low as 200°F (a typical organic Rankine Cycle is shown in Figure 6). Unfortunately, the 300 KW system is their smallest unit, and it is still oversized for the amount of energy available at the Tad's Enterprises site. Since it is felt that a custom design would be clearly cost prohibitive, this discussion will be presented on the basis that the Ormat 300 KW system can be utilized,

FIG 1 - CYCLE DIAGRAM

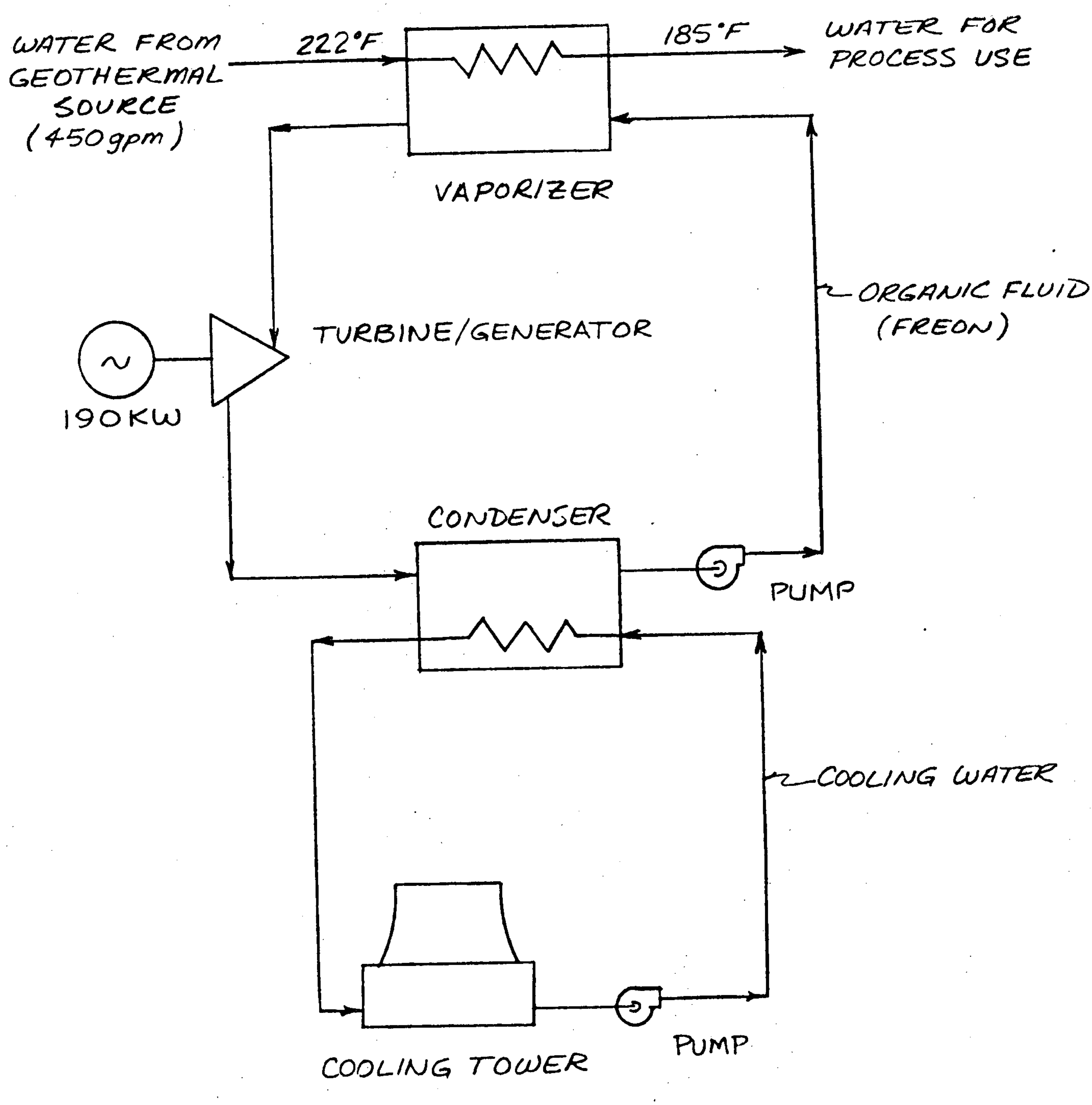


Figure 6

ULTRASYSTEMS ENGINEERS AND CONSTRUCTORS INCORPORATED IRVINE, CALIFORNIA	ORGANIC RANKINE CYCLE	Design: IBR	Checked:		
		Date: 8-81	Job No.	Sh. No.	

SFES-1/Rev. 6/77

either by operation at reduced load or by increasing the geothermal fluid flow to a point where full load operation can be achieved. The design basis for this application is a geothermal fluid (water) flow of 450 gpm at 222°F and 40 psig at the well head. This represents a usable heat input of around 8.5 million Btu/hr. The overall cycle efficiency quoted by the manufacturer for the ORC system is in the range of 7 - 10%. This means that, at the design flow rate, only around 200 KW could be generated. (It would require a geothermal fluid flow of around 650 - 700 gpm to reach the 300 KW design capacity of the system.) This standalone case ignores the present use of the geothermal fluid in the ethanol plant, and the restrictions that would be placed on the geothermal effluent fluid temperature from the power plant.

The only energy requirement not accounted for in the manufacturer's net output rating is that of the cooling water system. For this application a closed cycle cooling water system would be utilized which would most likely include a mechanical draft cooling tower. The cooling tower pump and fan energy requirements would reduce the system output by about 10 - 15 KW to approximately 190 KW.

Economics

The installed cost for the 300 KW Ormat unit is around $500,000. This includes the skid mounted ORC package, concrete foundations, cooling tower, circulating water pumps, and interconnecting piping. The maintenance costs associated with the unit are minimal, and are not expected to exceed $10 - 20,000 per year. Operator attendance is not required (although the equipment should be inspected daily), and the manufacturer is quoting an excellent machine reliability. The only materials that are required from a maintenance standpoint are the organic fluid itself (usually Freon), and water treatment chemicals for the cooling water system. Typically, 1 - 2% of the organic fluid will leak through pump and turbine seals during the course of a year.

The revenues generated by such a facility are determined by the metering arrangement one chooses to have with the local utility. Two options are available. Under the first option, the cogeneration facility would sell all power to the local utility, Sierra Pacific Power Company. Any power required by other facilities owned by Tad's Enterprises would be purchased separately from the utility. Under the second option the cogeneration facility would "sell" power to the ethanol refinery, and only surplus power would be sold to the utility. The second option would appear to be preferable since the utility avoided cost payment (the amount the utility will pay for power) is less than the refinery must pay for power from the utility. Thus the cogeneration facility can increase its revenues by selling power to the ethanol refinery at the same price as the refinery currently pays Sierra Pacific Power.

The current avoided cost rate published by Sierra Pacific Power for purchases of less than 100 KW is $.0409 per kilowatt hour for power, plus $.0061 per kilowatt hour for capacity based on the lowest monthly power output during the current or previous eleven months. These rates are in effect for three months beginning August 1, 1981, and will be adjusted quarterly. The rates for facilities producing over 100 KW are not published but are instead negotiated with the producer. However it is safe to assume that the rates for a 200 KW facility will be similar if not identical to the published rates.

The power sales price currently charged by Sierra Pacific Power for facilities of between 50 and 1,000 KW is $.0495/KW plus a demand charge of $180/mo and $3.60/KW for all demand in excess of 50 KW.

A brief economic evaluation of the proposed cogeneration facility is shown in tabular form in Table 2. As can be seen by this evaluation, the cash flow from such a project is low unless the early losses generated by the facility could be utilized to full advantage to offset other income by Tad's Enterprises. This analysis ignores the fact that the geothermal effluent temperature is too low for most of the process heating needs in the ethanol plant and an expensive reheat would be required. Coupling

TABLE 2 ECONOMIC ANALYSIS

YEAR	1	2	3	4	5	6	7	8	9	10
ELECTRIC POWER REVENUES										
Power Sold To Utility	35	39	42	47	51	56	62	68	75	83
Power Sold To Refinery	44	48	53	59	64	71	78	86	94	104
TOTAL	79	87	95	106	115	127	140	154	169	187
COSTS										
Depreciation	75	110	105	105	105					
Operation and Maintenance	20	22	24	27	29	32	35	39	43	47
Interest Expense @ 17%	85	77	68	60	51	42	34	26	17	9
General & Administrative Expense	2	2	2	2	2	3	3	3	3	4
TOTAL	182	211	199	194	187	77	72	68	63	60
Income (Loss) Before Taxes	(103)	(124)	(104)	(88)	(72)	50	68	86	106	127
Investment Tax Credit	(50)									
Energy Tax Credit	(50)									
Income Taxes	0	0	0	0	0	0	0	0	0	0
Net Income (Loss)	(203)	(124)	(104)	(88)	(72)	50	68	86	106	127
Depreciation	75	110	105	105	105					
Principal	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)
Net Cash Flow	(178)	(64)	(49)	(33)	(17)	0	18	36	56	77

Assumptions

1. Electric power revenues, purchased power cost, and O&M costs are escalated at 10%.

2. Cogen facility net output is 190KW at a capacity factor of 91%, (8000 hr/yr. operation) power sold to utility is 90KW. Power sold to ethanol refinery is 100KW.

3. Utility rates for year 1 are based on rates in effect for August, 1981: utility avoided cost rate is $.048/kw (including capacity credit) purchased energy cost is $.055/kw (includes demand charge).

power production with alcohol production is not economically feasible with the current geothermal well and pump.

Installing a new well and pump to deliver 700 gpm of geothermal fluid to a stand-alone binary cycle power plant would cost an additional $100,000, a capital cost increase of 20%. Gross generator output would be 300 KW versus 200 KW in the case considered above. However, the new geothermal fluid pump would consume 60 to 75 KW, offsetting most of the gross output gain. Hence the economics would be only marginally better. Considerable revenue would need to be gotten from a new user of the 185°F geothermal effluent in order for the application to be economically attractive.