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PRELIMINARY INVESTIGATION
DESALTING OF GEOTHERMAL BRINES IN THE IMPERIAL VALLEY OF CALIFORNIA*

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DISCLAIMER

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1.0 Introduction and Summary

In the area immediately southeast of the Salton Sea near Niland in Imperial County, 12 exploration wells were drilled between 1957 and 1964 to depths between 4,700 and 8,000 feet. Natural steam varying from 500° to 700°F associated with sodium-calcium-chloride brine having a salinity of about 30 per cent has been recovered from these wells which are distributed through an area of at least 6 miles long and 2 miles wide.

Farther south, geothermal energy is being developed commercially in the Cerro Prieto area below Mexicali, Mexico, where at least 17 wells have been completed. A contract has been signed for a Japanese steam power plant of 75 MW capacity for delivery in 1970. The Mexican brine contains 2 to 3 per cent dissolved solids.

Preliminary geologic investigations have indicated that the Mexican geothermal field may extend into the Imperial Valley. The total geothermal brine reserves may be of the order of 2,000,000,000 acre-ft. Robert W. Rex of the University of California has proposed that this resource (if it exists) could be developed at a rate of 3.6 million acre-ft/yr (equivalent to 20,000 MW of electric power). See Table I.

There is no convenient way to dispose of the brine at present. Some possibilities which might be developed include the following:

1. Re-injection into the geothermal aquifer.
2. Desalting of a portion of the brine, with the blowdown being re-injected. This is the preferred alternative.
3. If the Salton Sea were abandoned, desalting of Salton Sea inflows plus geothermal brines. The blowdown could drain into the Salton Sea or be re-injected.

The hot brines at the well head contain sufficient energy for the desalting process. Recovery of 40-80% of the flow as product appears to be feasible. This could amount to 1.5 to 3 million acre-ft/yr. In addition, if the Salton Sea were abandoned, 1 million acre-ft/yr of inflow could be desalted.

The Imperial Valley is an area of intensive irrigation with water imported from the Colorado River. The Colorado River water has been increasing in salinity and further increases are expected. There would therefore be a strong local demand for desalted water produced from geothermal brines.

TABLE I

Geothermal Summary Information*

Geothermal fields suggested in the Imperial Valley: 6-9

Geothermal brine reserves: 1,000,000,000 acre-ft

Temperature range of brine in the ground: 500-700°F

Total number of wells projected: 1000-3000

Surface pressures of flowing wells: 300-400 psi

Surface temperatures of flowing wells: 300-400°F

Flow rates per well (11 3/4" pipe): 1,200,000 pounds per hr (10.6 acre-ft/day)

Depth of typical well: 5,000 feet

Brine salinity (Mexican type): 2-3 per cent dissolved solids

Brine chemistry: chlorides of sodium, potassium, and calcium

Cost of typical well: $200,000**

Projected production rate of total Imperial Valley geothermal wells:

3,600,000 acre-ft/year to 10,000,000 acre-ft/year

Electric power with 1000 wells: 20,000 megawatt

Steam price per kw-hr: 0.36 mils

Heat price: 2 cents per million British Thermal Units

*From Robert W. Rex, "Investigation of the Geothermal Potential of the Lower Colorado River Basin," Phase I - The Imperial Valley Project. The entire report is an appendix of this report.

**Rex increased estimated cost from $100,000 to $200,000 in letter dated April 6, 1970.

Assuming that exploratory wells will be drilled in the Imperial Valley to produce 2-3% geothermal brine, it is suggested that a desalting pilot plant be associated with the project to develop an economic desalting process. The process will be unconventional in that waste heat must be rejected to atmosphere in wet or dry cooling towers. The presence of large amounts of carbon dioxide, hydrogen sulfide and silica in the system will require careful selection of process parameters and materials. The pilot plant would process up to about 75,000 gallons of brine per day. It is anticipated that a pilot plant program extending over 3 to 5 years would cost about $1 million, including the cost of the facility, its operation and development.

2.0 Summary of the Problems

In normal seawater desalting, feed to the desalting plant is obtained cold, steam is purchased to heat the feed (to a maximum temperature of about 250°F), and the waste heat and brine are readily discharged to the sea. In the present study, feed is obtained at about 400°F, waste heat must be rejected to atmosphere, and waste brine must be reinjected into the ground or evaporated to dryness. It is therefore anticipated that the process equipment for geothermal brine desalting will be substantially different than that generally used for seawater desalting.

In addition, the geothermal brines include substantial quantities of dissolved H_2S, CO_2 and silica. These constituents give rise to requirements for gas removal and for control of silica scale. There are special corrosion and materials selection problems as well.

3.0 Chemistry and Materials

3.1 Liquid and Vapor Composition

Table II gives some analyses of brines produced from the Mexican field; the analyses are presumed to include a mixture of both liquid and condensed vapor. The most probable compositions (M-5 and M-8) are high in silica, CO_2 and H_2S and contain no sulfate.

Vapor compositions are not at all reliably known. Table III gives some data provided by Rex. The analysis indicates major CO_2, and some hydrogen and methane. After flashing nearly all CO_2 and H_2S, go into the vapor phase and little remains in the brine.

TABLE II

Analyses of Geothermal Water from Mexican Wells
(pH ~7.5)

Well No.	Na	K	Li	Ca	Mg	Cl	Br	I	Fe	SO_4	HCO_3	H_3BO_4	SiO_2	CO_2	H_2S	Total Hardness (as $CaCO_3$)	Total Dissolved Solids (TDS)
	(Values in ppm)																
1-A	4,450	600	12	210	30	7,420	5.2	1.0	nd	7.0	52	52	240	nd	nd	699	13,082
M-3	5,310	1,100	17	310	11	9,680	10.0	2.8	0.2	15.0	60	55	480	680	218	820	18,041
M-5*	5,820	1,570	19	280	8	10,420	14.1	3.1	0.2	0.0	73	71	740	1,600	700	733	19,018
M-6	5,000	504	11	388	33	9,000	12.6	2.5	nd	16.4	158	21	151	420	37	1,106	18,412
M-7	5,250	910	13	230	18	9,310	9.2	2.6	nd	3.4	71	32	390	940	180	649	16,240
M-8*	6,100	1,860	17	390	6	11,750	14.3	3.2	nd	0.0	890	115	770	nd	nd	1,000	21,915

*Rex states that samples M-5 and M-8 are the most probable compositions of normal production of brine.

TABLE III

Analyses of Gas from Mexican Geothermal Wells

(Mol %)

Source	M-5	M-5	1A
Components			
Methane	26.7	10.9	10.41
Ethane	0.4	0.3	0.08
Hydrogen	21.1	9.7	0.04
Nitrogen	4.3	7.2	2.91
CO	1.3	1.0	-
Oxygen*	0.5	1.8	-
H_2S	0.1	0.1	0.24
CO_2	45.5	68.9	86.3
Argon	0.1	0.1	-

*From air leakage into sample. There is no O_2 in the geothermal brine.

The analysis in Table IV, taken from a report on New Zealand geothermal waters, indicates that virtually all of the CO_2 and H_2S are in the steam phase. It seems reasonable to assume at this point that the bulk of the non-condensables will join the steam phase. These gases are corrosive of themselves and are even more so in the presence of oxygen. The operation of a turbine and of a surface condenser for the turbine exhaust will therefore face the hazard of corrosive gases, aggravated by oxygen in the event of air inleakage to the vacuum system, and the necessity of a high vent rate to prevent blanketing of the surface by non-condensables.

Some of the H_2S will redissolve in the condensate and make it taste and smell awful! The rest will dissolve in the coolant to the barometric vent condenser where it will be a nuisance if that water is later used as a coolant.

3.2 Recovery of Dissolved Gases

As noted in Table IV most of the carbon dioxide, hydrogen sulfide, ammonia and traces of other non-condensables will be in the same phase. To obviate the need for special materials of construction and to reduce non-condensable venting, it would be highly desirable to remove these contaminants from the steam prior to its entering the turbine. This would make it possible to utilize conventional turbines widely available from competitive suppliers. Because of the extremely large steam source in the Imperial Valley, much larger and cheaper turbines than normally used with geothermal steam might be practical.

In some of the proposed flowsheets these non-condensable gases will be vented from a VTE reboiler operating at 400°F. The H_2S in the offgas could be recovered either as elemental sulfur or as sulfuric acid. Recovery as elemental sulfur should be feasible using an adaptation of one of the processes used in a petroleum refinery to recover sulfur from "sour gas." Oxidation of H_2S to elemental sulfur using air or oxygen also appear to be worthy of investigation.

At these temperatures (400-600°F), the oxidation of H_2S should be rapid and it would probably react with a near stoichiometric quantity of oxygen. If a stoichiometric reaction occurs, 0.5 lb of oxygen would be needed for each pound of sulfur produced. A captive oxygen plant will produce oxygen at \$4 to \$8/ton, thus the cost of oxygen would be about \$2 to \$4/ton of sulfur recovered.

TABLE IV

Discharge Fluid Composition (New Zealand)

Constituent	Concentration in Steam Phase, Parts per Million by Weight	Concentration in Water Phase, Parts per Million by Weight
Carbon Dioxide	5,400	5
Hydrogen Sulfide	140	0.5
Ammonia	15	3
Boric Acid	0.6	160
Fluoride (F^-)	0.03	6
Chloride (Cl^-)	Nil	1,500
Sodium	Nil	900
Potassium	Nil	60
Silica	Nil	300

Effect of Pressure on Equilibrium Water-Phase Composition (New Zealand)

Pressure (psig)	Temperature (Degrees F)	Calculated Dryness Fraction of Steam	Approximate Water-Phase Composition, ppm					
			CO_2	H_2S	NH_3	Cl^-	H_3BO_4	SiO_2
0	212	0.38	0.5	0.05	-	1520	190	350
85	327	0.28	5	0.5	3	1500	160	300
200	383	0.23	15	1	-	1400	150	280
400	446	0.15	50	4	-	1300	135	250
600	487	0.10	120	8	-	1200	130	240
800	520	0.05	330	17	-	1120	120	225
1000	545	0.00	1500	40	5	1080	115	215

If a VTE reboiler is not used, then much of the H_2S will dissolve along with CO_2 in the steam condensate from the turbine condenser. Conventional methods of removal of H_2S from water are aeration, with pH reduction to pH 4.5, chlorination or ion exchange. Aeration alone will reduce the H_2S content to 1-2 ppm. A polishing treatment with either chlorine or ion exchange is necessary to remove the residual.

At a concentration of 500 ppm H_2S, the equivalent of two tons of elemental sulfur could be recovered from a million gallons of water. The current price of sulfur is \$30-\$40/ton; 66-degree Baume sulfuric acid is \$31/ton. Credit for sulfur recovery could be a significant benefit to the total economics of the geothermal operation.

Carbon dioxide is also a potential by-product if marketing conditions warrant its recovery. CO_2 has been produced commercially from geothermal steam before.

3.3 Removal of Silica

Removal of soluble silica from water is generally carried out in conjunction with the hot lime or lime-soda softening process and is accomplished by the use of magnesium compounds under controlled conditions of temperature, retention time, pH (optimum pH$\cong$10), and recirculation. If the water to be treated does not contain sufficient magnesium, other magnesium compounds are added; e.g., Epsom salt, calcined magnesite, dolomitic lime, magnesium oxide, or magnesium carbonate. For 95% silica removal, magnesium equivalent to 5 MgO:1 SiO_2 is required at pH 10 with retention times of 15 min to 1 hr. On a weight basis, three times more dolomitic lime than MgO is needed to remove the same amount of silica.

Because of the high silica content (150-770 ppm SiO_2) and the low magnesium concentrations of the geothermal streams, the large amount of chemicals needed to remove the silica would make the process prohibitively expensive. Even if cheaper substitute minerals containing magnesium were available, the long retention times and problems of solids handling at high temperature and pressure preclude the use of this general method for economical silica removal.

An alternate silica removal scheme is being developed by Johns-Manville Products Corporation* under sponsorship of the Office of Saline Water which involves the use of activated alumina to sorb the silica. The alumina is then regenerated using sodium hydroxide solution. Work to date has been with brackish waters which contain relatively low concentrations of silica (up to 32 mg/ℓ) and low hardness (≤500 ppm TDS). The effectiveness of silica removal and the cost of regeneration are affected markedly by hardness; e.g., they estimate 1.6¢/1000 gal to remove 95% of the silica at 40 mg/ℓ hardness, but 6.25¢/1000 gal for 95% removal at 400-500 mg/ℓ hardness. With the higher levels of SiO_2 and hardness which are contained in the geothermal streams, the regenerate cost alone is estimated to be 16-20¢/1000 gal.

The silicon in these geothermal waters has been determined to be in the form of soluble orthosilicic acid, H_4SiO_4, and is reported to precipitate slowly as the water is cooled. Therefore, it is possible that the silica which precipitates may not form deposits or otherwise adversely affect the distillation process. As noted in Figures 1 and 2, the solubilities of silica and quartz drop with decreasing temperature. Thus if the blowdown were allowed to stand at ambient temperature in a settling basis where silica could precipitate, the clarified water should be suitable as a coolant stream for a distillation plant without subsequent deposition of silica scale on heat transfer surfaces.

In the proposed process cycles the hot brine is cooled in the flash vessels of the evaporator and subsequently in a retention basin where the precipitated silica would hopefully settle out prior to using the water as coolant in the heat exchanger tubing. Consequently, fouling the heat transfer tubing with silica scale would be avoided.

Mexican experience has shown that silica scale is deposited inside the well bore where some of the brine flashes to steam. Similar deposits are to be expected in the flashing orifices of a desalting plant. The Mexicans remove the deposits by reaming the bore hole once or twice a year. Mechanical removal of silica scale from the internals of an evaporator could pose a serious economical penalty on the process. Some means of avoiding silica scale buildup in the evaporator should be sought if it does indeed occur.

*Characterization and Removal of Silica from Webster, South Dakota., and Roswell, New Mexico, Well Waters, OSW R&D Progress Rept. No. 286 (Jan. 1968).

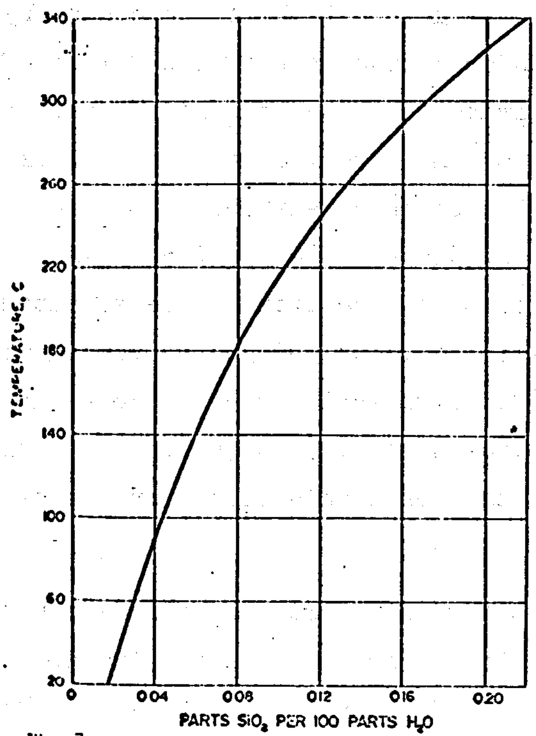

Fig. 1. Solubility of silica in water up to 340°C. Re

C. S. Hitchen, A Method for the Experimental Investigation of Hydrothermal Solutions with Notes on Its Application to the Solubility of Silica, *Bull. Inst. Mining Met., No. 364* (1935).

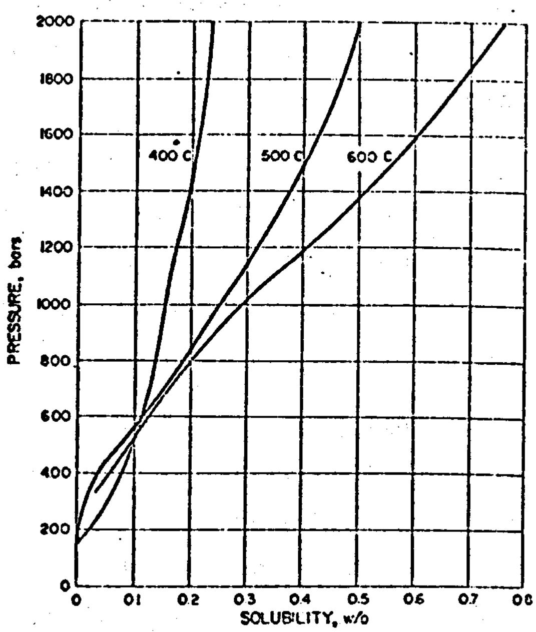

Fig. 2. Solubility of quartz in superheated steam.

G. W. Morey and J. M. Hesselgesser, The Solubility of Some Minerals in Superheated Steam at High Pressures, *Econ. Geol., 46,* 821-835 (1951).

Possibly the use of additives or pH adjustment to modify the precipitation characteristics of the silica could make them nonadherent. Alternately, coatings such as Teflon on critical areas of the evaporator internals might prove satisfactory.

Rex has suggested that a caustic flush performed on an intermittent basis might suffice to solubilize the silica deposits.

3.4 Removal of Alkalinity

Geothermal waters vary widely in alkalinity, 52-800 ppm HCO_3^- and hardness, 649-1100 ppm (as $CaCO_3$). The formation of alkaline scale, $CaCO_3$, during distillation could be eliminated by neutralizing the bicarbonate alkalinity and subsequent degassing to remove the evolved CO_2.

The reaction between HCO_3^- and H_2SO_4 should be rapid at 400-600°F. Based on our previous work with deaerators, the CO_2 should be removed effectively in a simple spray column with controlled venting. No column packing should be required.

With a captive sulfuric acid plant the cost of acid treatment would be about 1¢/1000 gal for feed water containing 100 ppm HCO_3^- alkalinity.

Cost for waters of other alkalinity would be directly proportional to the HCO_3^- content.

For water of very high alkalinity, i.e., $\geq$400 ppm HCO_3^-, the cost of acid treatment using manufactured acid will be prohibitive. In those cases it might be possible to oxidize the H_2S in the water to SO_2 in situ. The SO_2 would then react with the HCO_3^- to prevent $CaCO_3$ formation. An investigation of the kinetics of the oxidation of H_2S to SO_2 at these temperatures would be required to determine the feasibility of such a scheme.

Alkalinity hardness can also be removed by the addition of slaked lime to precipitate $CaCO_3$. While this is an attractive alternate to acid treatment and decarbonation at ambient temperature, the problems attendant with handling these solids at elevated temperatures and pressures appear to preclude the use of this method for treating geothermal water.

More reliable chemical analytical information is needed to characterize the chemistry of the brine and to obtain quantitative data on the distribution of the non-condensables in the steam and brine phases.

3.5 Materials

Published information on the corrosion of materials of construction by geothermal steam is sparse. Tests results on the corrosion of a variety of metals and alloys in low-pressure geothermal steam from a single well were reported by New Zealand workers in 1957.* Most engineering alloys were moderately susceptible to steam corrosion. Only premium materials such as titanium and some austenitic stainless steel displayed high resistance to attach in the specific environments tested. Stress-corrosion cracking occurred in hardened 13 Cr stainless steel, hardened low-alloy steels and aluminum bronze. Severe corrosion was noted when oxygen was present. Common heat exchanger materials such as the cupronickels were not evaluated.

Published data* indicate that type 316 stainless steel displayed satisfactory resistance to corrosion by both steam and liquid phases in the New Zealand geothermal fields. Alcoa 3S aluminum suffered pitting corrosion in these environments, however, one of the aluminum alloys may be more corrosion resistant. Titanium was essentially unattacked and would be an excellent choice if its cost is reduced as has been projected.

The selection of materials for the construction for a distillation plant operating on geothermal water will be largely influenced by the normal dissolved gases in the water and steam, particularly H_2S, CO_2, and traces of ammonia and hydrocarbons present in many of the wells. Because of the high CO_2 content of most geothermal waters, they are expected to be extremely aggressive toward normal concrete. Special cements containing a high silica content which are similar to those used for cementing oil wells have proved satisfactory for application in geothermal wells; however these may be prohibitively expensive for the fabrication of large structural components of distillation plants.

Because of the varying chemistry of different geothermal waters, it is doubtful that the selection of materials can be predicted on generalized corrosion test data. An extensive test program will be needed using the specific environment of interest to provide a basis for the selection of the most economic materials.

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*T. Marshall and A. J. Hugill, "Corrosion by Low-Pressure Geothermal Steam," Corrosion 13 (5), (May 1967).

A general laboratory test program using simulated environments would be of limited value because of the interrelationship of the many variables such as pressure, velocity, water chemistry, and mud or silt content of the water could not be satisfactorily duplicated in the laboratory. An on-site testing program should be conducted at the selected plant site during the initial stages of the development of the project.

4.0 Proposed Process Cycles

4.1 Possible Methods of Heat Rejection

Rex proposes that geothermal, at an average temperature of 600°F and an enthalpy of 617 Btu/lb, be flashed down to 400°F for steam production. This will yield about 29% steam saturated at 400°F, and 71% brine at 400°F and a concentration ratio of 1.4. The turbine will extract some 200 to 250 Btu/lb of steam as work or about 50 to 70 Btu/lb of well brine. If we assume that the brine and steam will ultimately be liquid at 100°F and an enthalpy of 68 Btu/lb, then there is about 400-500 Btu/lb of well brine which must ultimately be rejected to a heat sink.

The possible heat rejection methods in the area appear to be air cooling in dry towers and evaporative cooling of the well brine in ponds, spray ponds, or wet towers. The air cooled condensers and coolers can be designed to extract product water while rejecting heat and reducing the amount of brine to be disposed of.

The evaporative cooling methods reject the heat and reduce the quantity of brine but reclaim no water.

If an alternate supply of cooling water were available, it may be preferable to the well brine. However, the rejection of heat to any water results in evaporative loss.

4.2 Desalting Process Components

This section explains several components which were considered. Section 4.3 explains several cycles. No attempt was made to select a "best" cycle.

4.2.1 Surface Condenser at Turbine Exhaust - The most common geothermal power cycle would use a barometric condenser to condense the turbine exhaust steam.

The turbine exhaust steam can be reclaimed as product - about 29% of the well brine - by condensing it in a surface condenser rather than a barometric condenser. The surface condenser can be cooled either by air or by recirculated brine which is in turn cooled by evaporation.

4.2.2 Single Effect VTE - A single effect of vertical tube evaporation provides the very attractive possibility of extracting a significant additional amount of water and of providing relatively clean steam to the turbine. In this arrangement the steam from the head separator (assumed to contain the bulk of the gases) is led to the steam chest of an evaporator effect where it is condensed for product water. The non-condensable gases are vented from the effect and the sulfur can be recovered from this stream. The brine from the separator (assumed to be low in gas content) is fed to the evaporator tubes where it serves as the coolant to condense the well head steam while producing an equivalent weight of clean steam at a temperature perhaps 10° lower. The brine entering the evaporator will be at a concentration ratio of about 1.4 and will exit at about 2.5X well brine. It will be essential that the solids originally dissolved in the brine remain in solution or suspension during this operation.

4.2.3 Flash Evaporator - Further water can be extracted from the 400°F brine by introducing it to a series of separators or a multistage flash evaporator and permitting it to flash down to the heat rejection temperature. The amount of the remaining water that can be extracted is a function of the amount of the heat transfer equipment installed, the method of heat rejection, and the solubility limits of the brine.

4.3 Illustrative Cycles

A number of combinations of equipment and cycles are possible and can be tailored to produce almost any ratio of yields of water, evaporative loss, and brine. Those shown here are indicative of the possibilities. The best cycle for a given situation would be a function of the value of water, the value of the recoverable chemicals, the liability of the brine, the solubility limits of the brine, the equipment capital cost, and the operating cost.

4.3.1 Vertical Tube Evaporator Cycle I - (Figure 3) - One of the possible cycles for using the single effect vertical tube evaporator described above extracts additional water from the remaining brine by flashing it down through a series of separators. These separators are similar to the New Zealand-type used at the well head. The exhaust from the turbine is recovered in an air cooled condenser. The condensate from the VTE is cooled by regeneratively heating brine. This heated brine joins the effluent brine from the VTE and is flashed through a series of separators. The vapor from each separator is recovered in an air cooled condenser. The remaining brine is evaporatively cooled to ambient in a pond. Such a cycle would extract about 70% of the water, use another 9% for evaporative cooling, and result in a blowdown concentration ratio of about 5. This blowdown concentration can be varied to suit the solubility limits of the brine by varying the amounts of extraction, air cooling, and evaporative cooling.

4.3.2 VTE Cycle II (Not illustrated) - If the solubility limits of the brine are such that it can not be evaporated in the VTE, it is still possible to obtain clean steam. The condensate from the steam chest is fed to the brine chest, flashed into the tubes, and re-evaporated to steam for the turbine. The non-condensables are handled as in VTE I above. The brine from the first separator can be flashed down through a series of separators to extract more water.

4.3.3 Flash Evaporator, Open Cycle, Figure 4 - The turbine exhaust steam, comprising about 29% of the water, is recovered in a liquid cooled, shell and tube condenser. The heat is ultimately rejected by evaporative cooling with a resultant loss of about 20% of the water. The 400°F brine is introduced to a multistage flash evaporator to recover about 16% of the water. Again the heat is ultimately rejected by evaporative cooling with a loss of about 20% of the water. In such a cycle about 45% of the water is recovered, about 45% lost to evaporative cooling, and about 10% remains as brine.

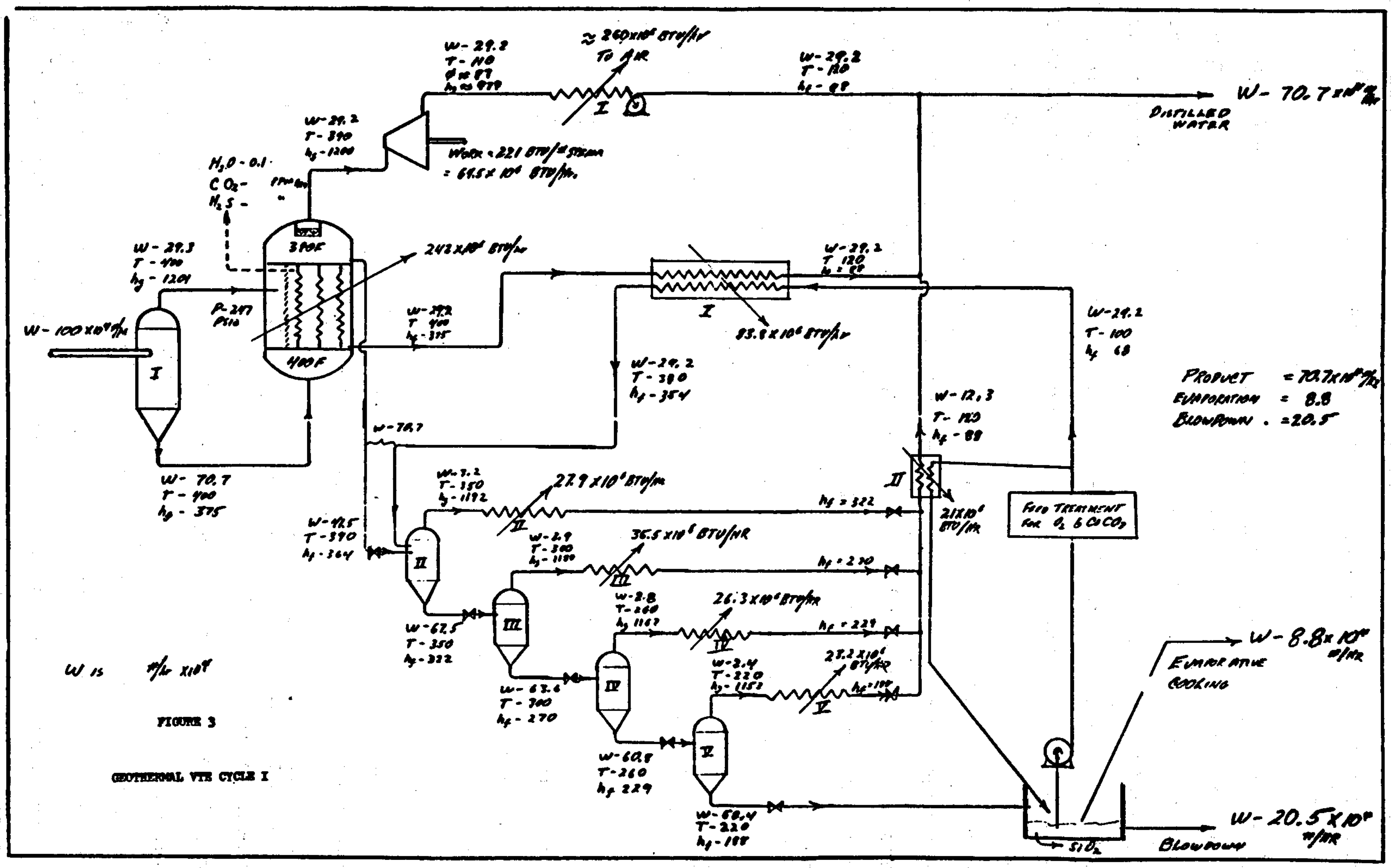
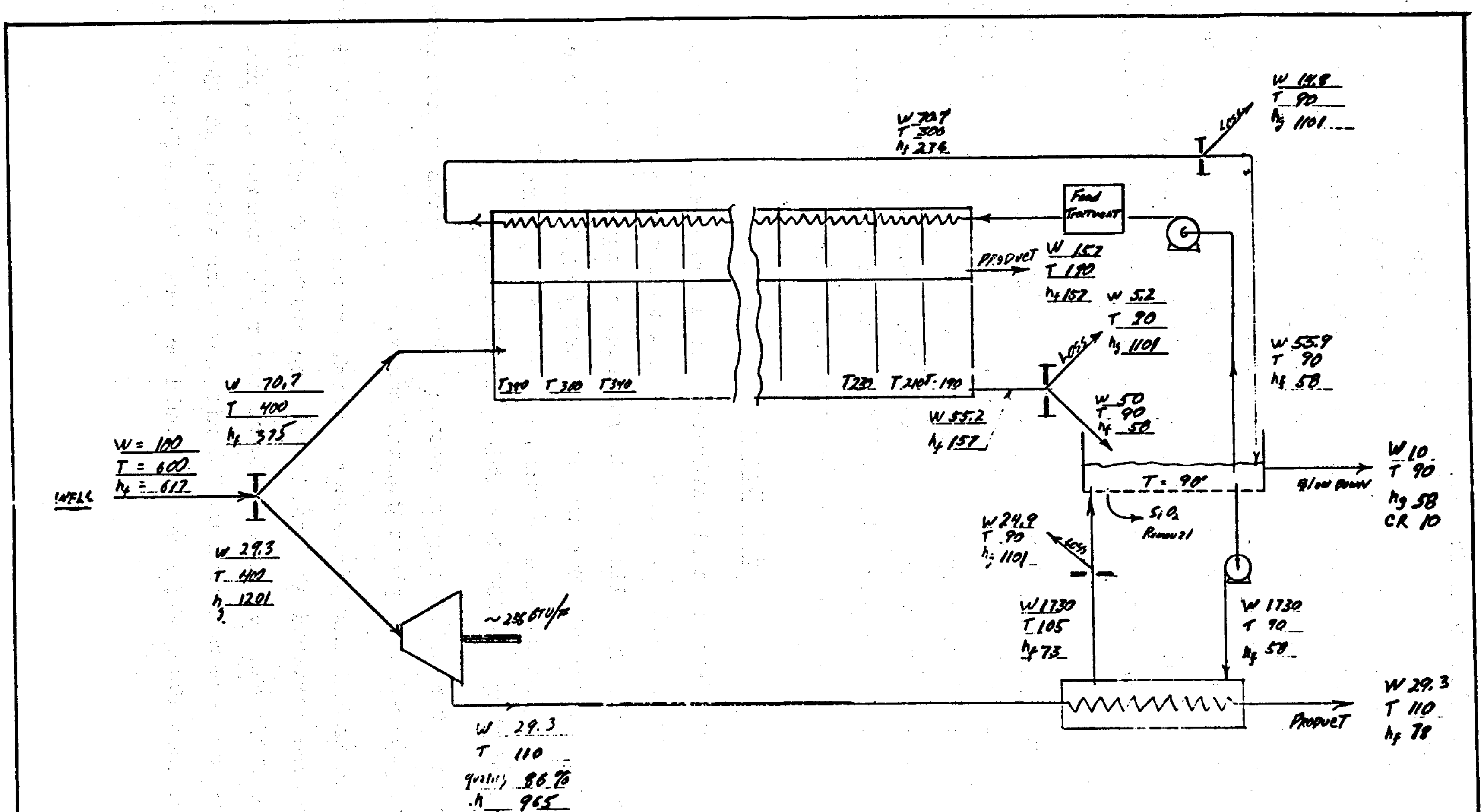


FIGURE 3

GEOTHERMAL VTE CYCLE I



PRODUCT 45.0 %
EVAPORATIVE COOLING 45.0 %
BLOWDOWN 10.0 %

NOTES
Specific heat assumed to be 1
Calculations are approximate
Cooling Tower assumed to reach 90 F

FIGURE 4
GEOTHERMAL OPEN CYCLE

Sept 3

4.3.4 Regenerative Flash Evaporator with Air Cooling I, Figure 5 - The turbine exhaust is recovered in a shell and tube liquid cooled condenser. The heat is ultimately rejected through the evaporative loss of about 29% of the water. The brine passes through a multi-stage flash evaporator to recover about 18% of the water. The coolant brine from this evaporator is flashed through a second evaporator where another 15% of the water is recovered. Heat from the second effect is rejected directly to the air by air cooled condensers. In this cycle about 61% of the water is recovered, about 29% is evaporative loss, and about 10% remains as brine.

4.3.5 Regenerative Flash Evaporator with Air Cooling II, Figure 6 - The turbine exhaust is recovered in an air cooled condenser with the heat being rejected directly to the air. The brine is flashed through two liquid cooled evaporators in series. The coolant brine from the second effect is air cooled. About 63% of the water is recovered, about 7% lost to evaporation, and 30% remains as brine.

5.0 Costs

An attempt was made to develop cost estimates for a representative process cycle (VTE cycle, section 4.3.1). It was assumed that one square mile of land was developed, with 25 wells at 1000 ft spacing, square pitch. This capacity is sufficient for 500 MWe and 51 Mgd, assuming 1 million lb/hr total flow per well. Because the geothermal steam is "cleaned" in the VTE, it was assumed that one 500 MW turbine could be used.

Table V gives an estimate of capital costs; Table VI gives a more detailed breakdown of the power-desalt plant capital costs.

Table VII gives an annual cost breakdown. Total annual cost is $19.25 million. If power were marketed at 3 mills/kwh and sulfur at $30/ton, then water would cost 24¢/kgal; revenues would be power 68%, sulfur 9%, and water 23%. If power were marketed at 3.6 mills/kwh and sulfur at $30/ton, then water would cost 10¢/kgal; revenues would be power 81%, sulfur 9% and water 10%.

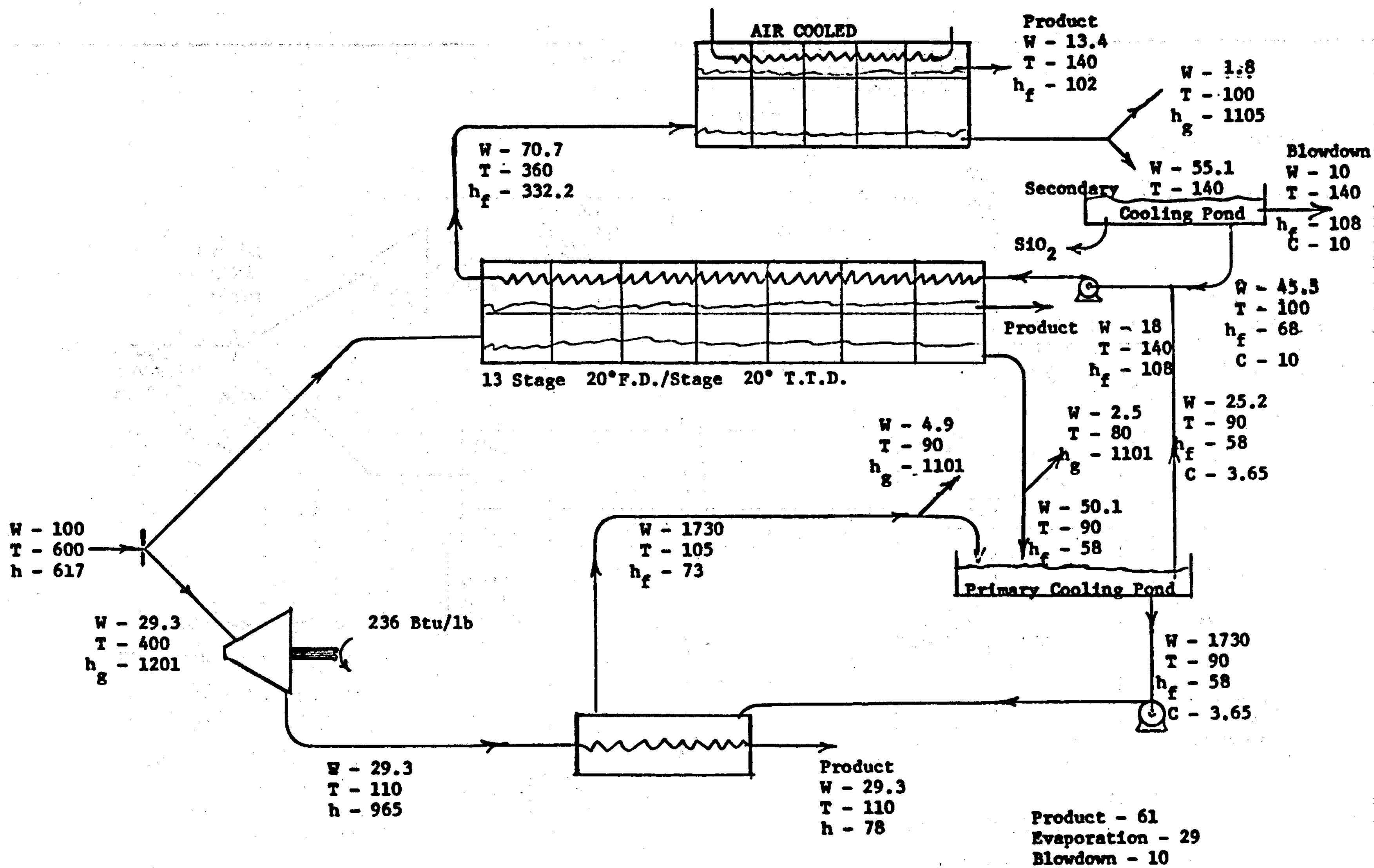


FIGURE 5

FLASH EVAPORATOR - W/Air Cooling I

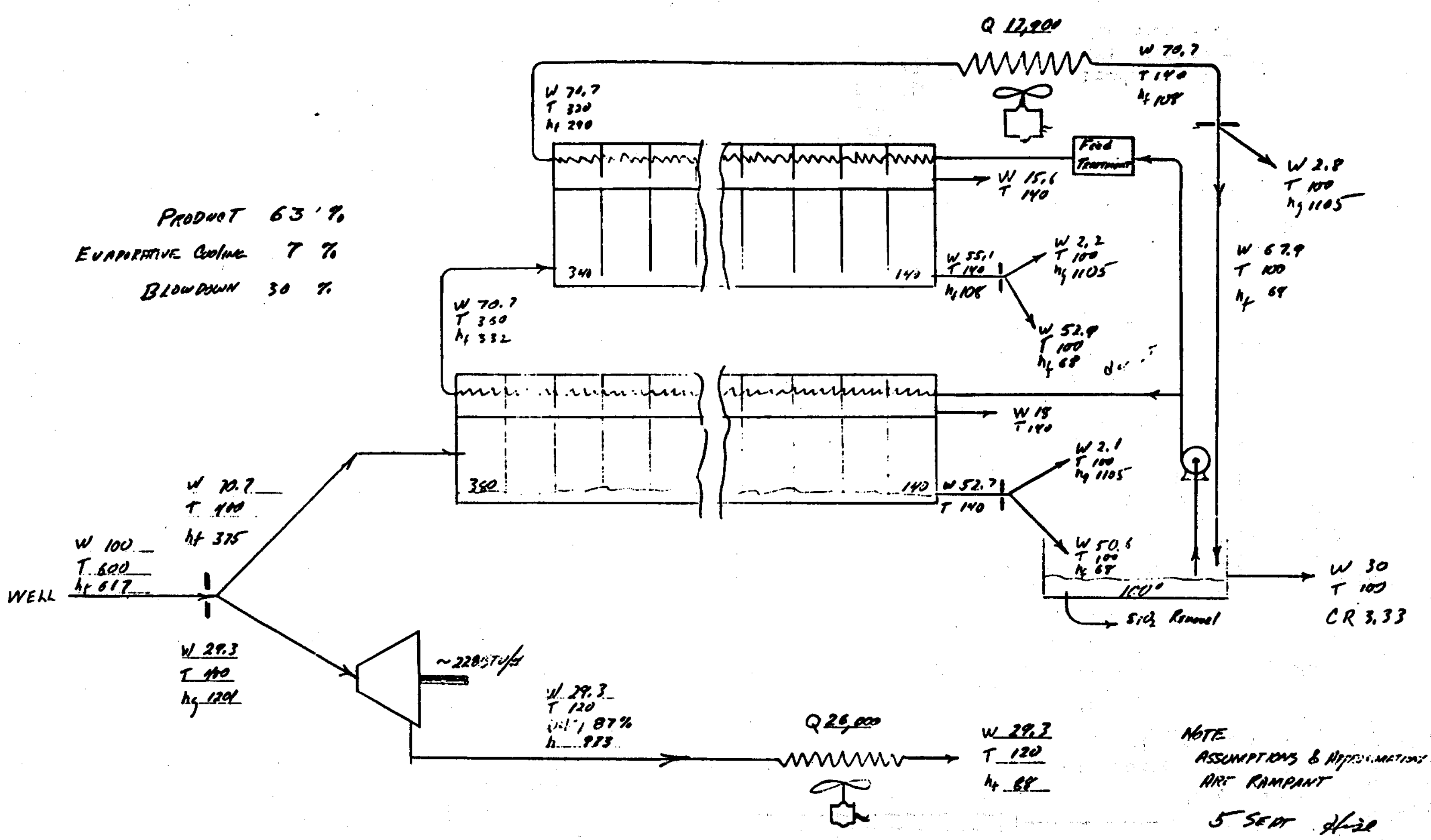


FIGURE 6

GEOTHERMAL FLASH EVAPORATOR WITH AIR COOLING

TABLE V

Estimate of Capital Costs

25 Wells, at $200,000 per well	$ 5.00 million
Power and Desalt Plant	
Allocated to Power*	55.35 million
Allocated to Desalting (25 units)	40.0 million
Brine Disposal	Not Estimated
Sulfur Recovery	Not Estimated
Total	$100.4 million

*The cost allocated to power includes all power facilities, steam piping from wells, contingency, indirect costs, and $25/kw allowance for heat reject.

TABLE VI

Estimate of Detailed Capital Costs, Power-Desalt Plant

Separators, carbon steel (125 units)	\$ 1.20 million
Air-cooled turbine condensers	16.85 "
Air-cooled condensers, other	2.05 "
VTE bundles, smooth Ti tubes, $\overline{U}$=800, tubes at \$2.20/ft, 25 required	3.47 "
VTE vessels, 25 required, 16'D x 30' high	10.25 "
Miscellaneous desalt equipment	3.18 "
Steam piping to turbine	7.85
500 MW turbine-generator	21.39 "
Subtotal	\$66.24
Contingency - 20%, includes items not estimated	13.25 "
Indirect costs	15.94 "
Total	\$95.43 million

TABLE VII

Annual Costs

Wells, Fixed cost @30%/yr, O, M & R @ 10%/yr, 25 wells	\$ 2.0 million
Power, Fixed cost and O, M & R @ 20%/yr	11.1 "
Desalting, " " " 12%/yr	4.8 "
Brine Disposal, @ 10¢/kgal	0.5 "
S Recovery, assume \$15/ton Cost	0.85 "
Total	\$19.25 million

Because the power production is not feasible unless brine can be disposed of, it is entirely possible that the power plant operator may have to pay a brine disposal charge to the desalting plant operator. This would permit both power and water to find marketable prices.

6.0 Conclusions and Recommendations

If R. W. Rex's estimates of the geothermal potential of the Imperial Valley are correct, then it is plausible that power and desalted water could be produced at marketable prices. The scale of operations could become large enough to have a significant economic impact on Southern California and on the Lower Colorado region.

If government agencies support substantial exploratory drilling to prove the geothermal reserves, then a fraction of this investment should be spent on desalting process development. The rationale for this recommendation is that desalting will be needed to dispose of the geothermal brines economically. Another good reason for this effort is that the Imperial Valley and the Lower Colorado urgently need some pure water to offset the growing salinity of the Colorado River.

The desalting effort is envisioned to consist of 2 phases, as follows:

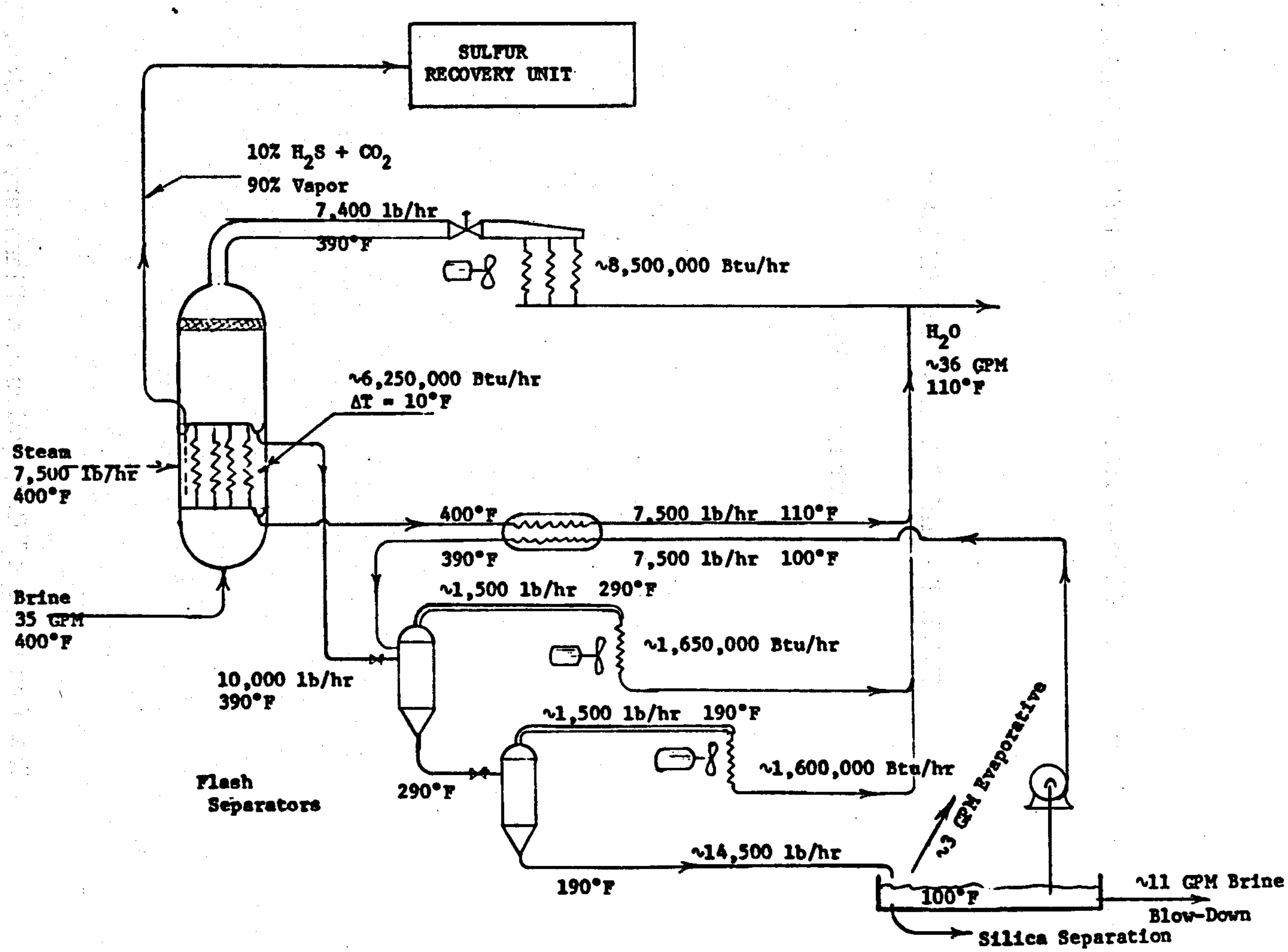
Phase 1 - Exploratory, consisting of laboratory analyses of brines and vapor, and conceptual cycle analysis, along the lines of this preliminary investigation. Cost of this phase should be $50,000 to $100,000 and it should be scheduled to coincide with exploratory drilling.

Phase 2 - Pilot plant, consisting of an initial outlay of about $200,000, and a total cost of up to about $1 million over 3 to 5 years assuming the application continues to be promising.

The equipment proposed for water extraction - vertical tube evaporators, evaporative cooling, air cooling, and flash evaporators - is developed equipment in commercial use in similar applications. This application departs, however, from others in the composition of the brine and in the available maximum working temperature and pressure. Cycles will have to be designed and tested for the temperature-concentration solubility characteristics of the geothermal brines. The problems one anticipates are those of the removal of the non-condensable gases, the deposition of solids on the heat transfer surfaces, and the corrosion of the heat transfer surfaces by the dissolved solids and gases. The initial investigations could be accomplished with a 20 to 50 gpm pilot plant consisting of a well head separator, a single effect vertical tube evaporator, one or more stages of flash separator, air cooled condensers for the generated vapors, and a sulfur recovery unit. A possible flowsheet is shown in Figure 7.

FIGURE 7

GEOTHERMAL BRINE PILOT PLANT
~50 GPM Total Input



APPENDIX

INVESTIGATION OF THE GEOTHERMAL POTENTIAL OF THE LOWER COLORADO RIVER BASIN

PHASE I - THE IMPERIAL VALLEY PROJECT

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Geothermal Summary Information

Geothermal fields suggested in the Imperial Valley: 6-9.

Geothermal brine reserves: 1,000,000,000 acre-ft.

Temperature range of brine in the ground: 500-700°F.

Total number of wells projected: 1000-3000.

Surface pressures of flowing wells: 300-400 psi.

Surface temperatures of flowing wells: 300-400°F.

Flow rates per well (11 3/4" pipe): 1,200,000 pounds per hour (10.6 acre-ft/day).

Depth of typical well: 5,000 feet.

Brine salinity (Mexican type): 2-3 percent dissolved solids.

Brine chemistry: chlorides of sodium, potassium, and calcium.

Cost of typical well: $100,000.*

Projected production rate of total Imperial Valley geothermal wells:

3,600,000 acre-ft/year to 10,000,000 acre-ft/year.

Electric power with 1000 wells: 20,000 megawatt.

Steam price per Kw-hr: 0.36 mils.

Heat price: 2 cents per million British Thermal Units.

* This estimate was increased to $200,000 by Rex in correspondence dated 4/6/70.

0.0 ABSTRACT

The Imperial Valley Project (IVP) is a program initiated by a team of staff members of the Institute of Geophysics, University of California at Riverside to develop the geothermal resources of the Lower Colorado River delta which includes the Imperial Valley of Southern California and adjoining areas. Initial efforts are concentrated on the Imperial Valley but later field studies will include work in Arizona, Mexico, and possibly Nevada to define the extent and quality of geothermal resources.

In the first phase of the study, already in progress, a combination of geological and geophysical methods is being employed to map out promising potential sources of geothermal energy.

Following a critical evaluation of the preliminary exploration phase, we propose to conduct extensive field tests to provide the essential data necessary to determine the economics of exploitation of geothermal energy for power generation, water desalination, and possibly mineral extraction.

If the preliminary economic evaluation is favorable we intend to pursue a full scale investigation involving a detailed scientific evaluation of the geothermal energy reserve of the entire geothermal area. This study is to be accompanied by engineering and economic evaluation of the potentialities for development of geothermal energy in the Lower Colorado Basin for water desalination and power generation.

The current phase of operation, costing some $40,000, is supported by federal, state, and industry contributions. This level of funding is permitting a minimum program of geophysical exploration and geothermal investigation over a small portion of the promising areas. If the preliminary results are favorable, additional support will be sought in order to complete the first phase of the project.

1.0 INTRODUCTION

The Imperial Valley Project (IVP) is an applied research program intended to provide geologic, hydrologic, engineering, and economic information necessary for development of the geothermal resources of the delta of the lower Colorado River.

The project is being directed in its initial phase by Dr. R. W. Rex, as the Principal Investigator, and Dr. T. Meidav, as the Geophysical Project Director. Both are members of the Department of Geological Sciences and the Institute of Geophysics of the University of California at Riverside. The two named investigators have the support of several other faculty members who are expected to join the study in its later phases when more support becomes available. The project is being administered within the Institute of Geophysics and Planetary Physics at Riverside.

The proposed study consists of a number of phases. The initial phase, already underway, is concerned with collection of basic geochemical and geophysical data to demonstrate the most useful and reliable techniques that might be employed to survey the geothermal energy resources of the Imperial Valley quickly and economically.

This initial effort is being supported by the U.S. Bureau of Reclamation, the National Science Foundation, and the Standard Oil Co. of California. Other industrial support has been solicited but at present is not available.

2.0 THE OBJECTIVES OF THE IVP

(1) Reduce the risk for exploitation of geothermal energy to the point where industry and government can cooperate to develop the large untapped geothermal resources in the Imperial Valley by locating the principal potential steam fields, determine their chemistry, size of reserves, and productive potential including direct testing of wells.

(2) Provide impartial scientific information to governmental and public agencies to assist in regional planning for optional energy and water resource development.

(3) Bring together potentially interested parties who might cooperate in forming an operating system to develop and control the presently underdeveloped water resources of the lower Colorado delta area, including groundwater, drainage water, Salton Sea water, and ocean water.

(4) Perform field and laboratory research needed to support planning, economic evaluation, and engineering feasibility studies.

(5) Train scientists and engineers in geothermal energy-related technology to provide personnel needed by industry and government to support development of this resource.

(6) Test and develop advanced scientific techniques for geothermal exploration in general which may be used in other areas as well, after having been tested and proven in the Imperial Valley.

3.0 HISTORY OF GEOTHERMAL DEVELOPMENT IN THE IMPERIAL VALLEY

Geothermal energy is being developed commercially in the Imperial Valley in the Cerro Prieto area south of Mexicali where at least 17 wells have been completed. A contract has been signed for a Japanese steam power plant with 75,000 Kw capacity to be completed in 1970 (Fig. 1).

U. S. developments have been largely restricted to the Buttes area at the south end of the Salton Sea (Fig. 1) where several test wells have shown the presence of a hypersaline hot brine that is of uncertain commercial value because of the excessive proportion of hypersaline brine to steam. Unlike the Mexican brine, the Buttes brine is highly corrosive on the slightest exposure to air, and toxic metals make potash recovery presently non-competitive with Canadian potash. Recovery of other metals including silver may be possible in the future but does not appear to be commercial at present.

The Buttes area is actually underlain by two separate types of geothermal brine. The deeper brine is the very hot hypersaline brine, while above it occurs a cooler less saline brine of approximately 1-3 percent dissolved solids that is noncorrosive. The contact between these two brines dips to the south. It is at approximately 2,000-2,500 feet at the I.I.D. well No. 1 near Red Hill; at about 5,000-6,000 feet at the Sinclair No. 1 about four miles south; and none found at all to a depth 13,000 feet at the Wilson No. 1 just east of Imperial. This same less saline non-metalliferous brine is also produced in the Mexicali steam field. Its widespread occurrence over most of the valley makes it attractive to try to locate areas where high temperature brines greater than 550°F come within 5,000 feet of the surface. Preliminary exploration over the past decade suggests that there are a number of possible geothermal locations in the Imperial Valley, some on federal, some on state, and some on private land.

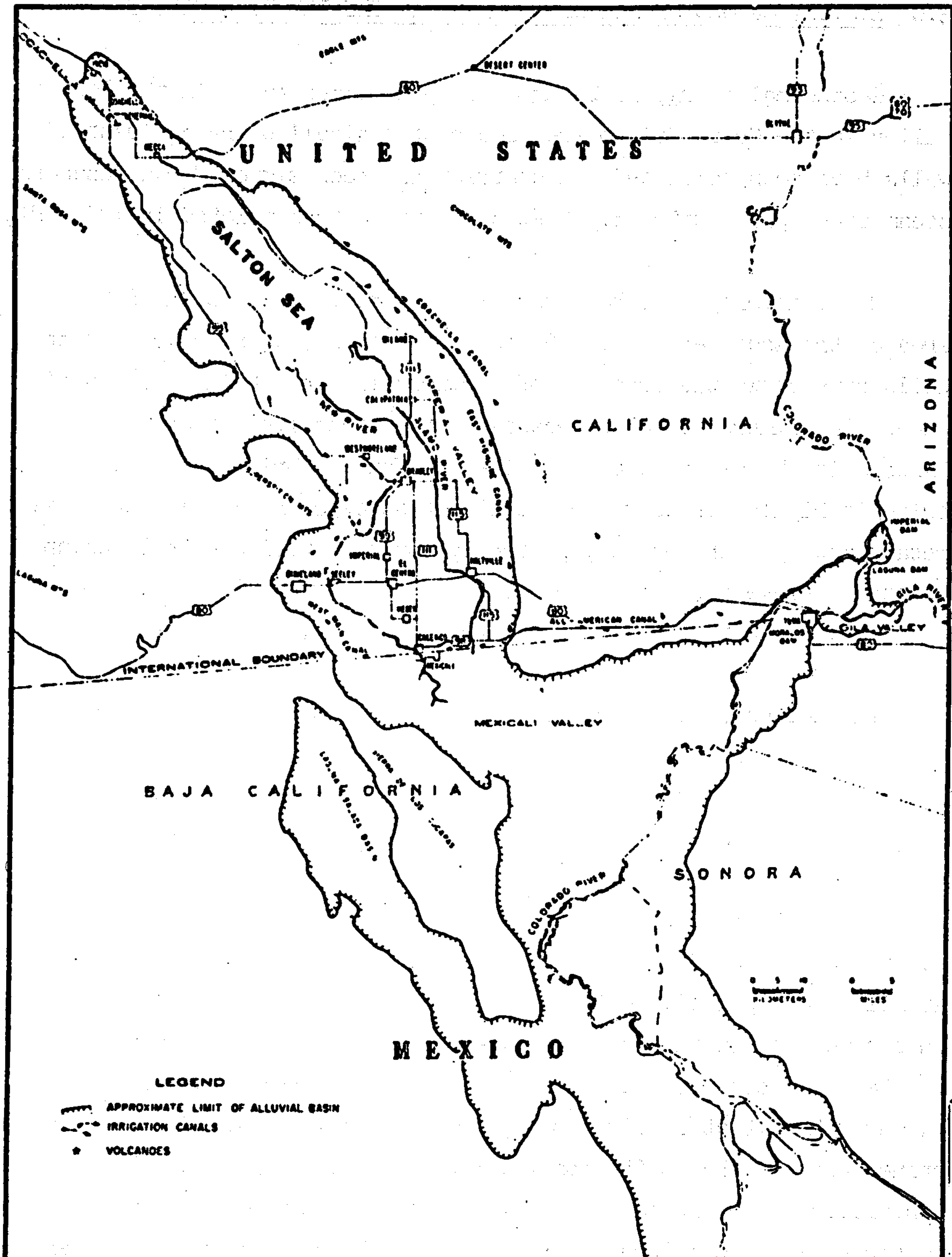

FIGURE 1

INDEX MAP OF THE IMPERIAL VALLEY

No significant commercial development of the steam potential of the Imperial Valley fields has occurred because of the problem of brine disposal. Approximately two pounds of brine are produced for every pound of steam and the brine disposal costs currently inhibit commercial development of steam. Consequently, development of a large market for geothermal brine is essential for development of the lower Colorado basin geothermal potential.

The only market evident for very large quantities of geothermal brine is for saline water conversion. Traditionally, water distribution falls into the public section of the economy. On the other hand, geothermal steam wells themselves involve application of sophisticated scientific technology developed by the petroleum industry in the course of steam-assisted oil recovery research. In addition, the individual steam wells will probably have a limited lifetime of five to ten years; will require careful specialized maintenance; and will need to be supported by a technology research program typical of oilfield technical service support. The logical division, therefore, is for private industry to drill and operate the wells and to sell steam and brine to public or semi-public agencies or utilities to produce potable water and power.

The problems of partial private and partial public sector contribution to geothermal development has led to an impasse in Imperial Valley geothermal developments where everyone seems to be waiting for someone else to make the first move. The Imperial Valley Project is intended to be a first move by the University of California to bring together both the public and private sectors of our economy in this area for the public welfare.

4.0 PROBLEMS EFFECTING FURTHER DEVELOPMENT OF GEOTHERMAL ENERGY IN THE VALLEY

We presently lack sufficient detailed scientific information to evaluate the economics of the geothermal potential of the lower Colorado basin. We need to know in considerable detail the location of potential steam fields; the amount of hot brine reserves; the chemical character and possible corrosiveness of the brines; the depth and shape of potential steam reservoirs to assist in well planning; and the origin and possible recharge mechanisms of groundwater in order to determine the life of the steam fields. We also need to determine the feasibility of pressure maintenance by ocean water or Salton Sea water injection; the maximum productivity of different reservoir sands; and possible sand formations that could be used for brine disposal.

If all the porosity of the sediments of the Imperial Valley were collapsed and the water squeezed out to the surface, the valley would be covered with a sea about 3000 feet deep. This is almost a thousand times the volume of the Salton Sea today. Consequently, the large groundwater reservoir in the valley could easily serve as a sink for the excess salts of the Salton Sea or of sea water charged to the groundwater reservoir for a period of 10-20 years at minimum.

Mexican-type brines contain 1.5 to 2.5 percent dissolved solids and can yield about 90-95 percent of their water without becoming saturated with salt. The Mexican-type brines contain no sulfate and the first phase to reach saturation is sodium chloride. Consequently, a desalination plant fed by geothermal brine might yield approximately 90 percent distilled water and about 10 percent concentrated brine which could be reinjected underground in cool areas. This would leave approximately 25 percent of the geothermal steam for industrial uses or power generation.

Cost figures at this stage are at best tenuous because all past desalination plant designs have been optimized for fossil or nuclear steam costs of 22-35 cents per million B.T.U.'s. We have set geothermal brine costs at about 1 cent per million B.T.U.'s with a reasonable premium for steam in order to pay the wells out in four years or less. At this price heat for desalination is almost free coming to about 12-15 dollars per acre-ft. Plant amortization and operating costs will probably come to 40 to 70 dollars per acre-ft.

The cost of geothermally desalinated water is obviously much greater than present Colorado River water and, therefore, it would have to be considered as incremental water in competition with Eel River water or Columbia River water. It appears most reasonable that development of a lower Colorado water grid could include this new distilled water and that withdrawals of Colorado River water could be made by exchange of Imperial Irrigation District Colorado River water allocations outside of the I.I.D. at desalinated prices and use of desalinated water locally in the Imperial Valley at Colorado River prices. Additional exchanges of Owens River water might be made for Colorado River water delivered to the Metropolitan Water District. This in effect would introduce a two level price structure for southwest U. S. water. Riparian rights holders would get their historical prices while newer buyers would have to pay incremental water prices. This effectively restricts new users to municipal and industrial users. For the purpose of regional development and growth consideration should be given to protecting agricultural access to riparian rights from municipal and industrial users who could afford to pay incremental prices.

Addition of salt-free distilled water to the I.I.D.'s water allotment would permit salinity reduction and reduce the amount of leach water needed for salinity control of irrigated areas. Consequently, desalinated water would help cushion the effect of the reduced Colorado River allocation to the I.I.D. as a consequence of recent court decisions. In addition, steam separated from geothermal brines at the well head would be available for power generation at very low cost. This steam is usually superheated a few degrees; has a pressure of 300-400 psi; and a temperature of 300-450^{o}F. Mexican experience in the next three years should demonstrate feasibility of geothermal power production in the Imperial Valley. The cost of geothermal steam is approximately 0.36 mils per Kilowatt-hour of electricity produced.

The steam fields will produce, at least for a number of years, from single phase brine reservoirs. It appears that produced steam could be sold at about 1-2 cents per million B.T.U. and pay out well and surface production equipment in about 24-48 months. The Mexicans have shown 1,000,000 to 1,200,000 pound per hour flowing wells to be reasonable and a large number of wells flow at friction-limited rates. Consequently, even larger wells should be tested in the future.

5.0 ULTIMATE POTENTIAL DEVELOPMENT IN THE IMPERIAL VALLEY

5.1 Reserves

An approximate estimate can be made of the regional geothermal potential of the Imperial Valley of California and Mexico based on the work of Rex (1965) and the Mexican studies. The values given are only approximate but serve to indicate the large size of the geothermal reserves. The key information known at this time is that the entire valley is a geothermal province with an average heat flow of two to three times the continental average. The key difference between the cool and the hot areas is that convective cells of hot waters rise along some of the faults and fault complexes in the valley and give rise to very steep temperature gradients in some local areas. In other areas low salinity cold waters move across the valley in shallow aquifers and local near surface heat flow is less strongly influenced by upward moving deep waters. Consequently, economic development of geothermal waters will occur in the areas of highest heat flow. However, geothermal wells in these shallow hot areas should drain geothermal fluids from the entire surrounding areas and the entire deep portion of the basin can be considered to be filled with geothermal brine.

The geothermal area is estimated to cover at least two million acres. There appears to be about 20,000 feet of sediment in the basin and if the lower 15,000 feet are filled with hot brine and we assume an effective average porosity of 10 percent, we would have three billion acre-feet of geothermal reserves or more than two hundred times the annual flow of the Colorado River. The heat content of the minerals which make up the nonaqueous 90 percent of the rock is slightly greater than that of the hot brine assuming 10 percent porosity and, consequently, injection of cold sea water as part of pressure maintenance program could extract additional heat and potentially nearly double the previous ultimate reserve estimate.

Production of ten million acre-feet per year of geothermal brine would, therefore, utilize approximately less than one hundredth of the total reserves in the valley.

Regardless of the nature of moderate errors in the above figures it is evident that the geothermal reserves are sufficiently large so as to open the possibility of making a significant contribution, perhaps by a factor of two, to the water supply of the southwestern United States providing sea water can be brought into the Imperial Valley.

5.2 Pressure maintenance by sea water injection at Yuma Mesa

One possible area for introduction of sea water is in the old Colorado channel at Yuma Mesa. Here dredging of the old channel and construction of a port for Mexico, California, and Arizona would introduce sea water into the upper delta.

Drilling in the Algodones Dunes which reach almost to Yuma Mesa indicates that a major prism of sand penetrates deep into the subsurface below the present dunes. If this subsurface extension is extensive and reaches the port area, it should be relatively easy to inject sea water below the present fresh waters into these deep sands and use them as an aqueduct to distribute cold salt water across the basin. There is as much as two hundred feet of drop from sea level to some of the prospective geothermal areas. The resultant pressure gradient should assist the spreading of sea water through the various aquifers in the valley.

The use of the Yuma port as a source of sea water for pressure maintenance is probably of equal or perhaps greater importance than commercial utilization by Arizona and California as a port.

5.3 Unknowns and further information needed

The validity of these estimates and extrapolations from preliminary data will have to be established. Specifically, we need to know the distribution of various types of waters, both saline and fresh; the nature and transmissability of various aquifers; the relationship of the flow patterns of both hot and cold waters; and the chemistry and quantities of the various geothermal brines. We, also, need to evaluate the costs of various engineering alternatives considering both the entire system and various subsystems.

5.4 Initial stages

Initial pressure maintenance efforts would not necessarily need sea water. Approximately 1,130,000 acre-ft per year of drainage water flow into the Salton Sea from the Imperial Valley. All of this water eventually evaporates leaving the salts behind in the Salton Sea where the salinity has been increasing. Diversion of some Salton Sea water and drainage water into a pressure maintenance operation could provide a means for stabilizing both the level and salinity of the Salton Sea at some preselected level lower than its present one. The residual geothermal brines from the desalination plant could also be reinjected into cool aquifers at intermediate depths as part of this program. Later development of a drainage system running to the sea, possibly along the banks of the ship canal or along the valley of the New River is a long range solution whose use would depend on an economic or technical advantage over subsurface disposal.

5.5 Geothermal wells

Approximately thirty successful geothermal wells have been drilled in the Imperial Valley. The great majority of these have flowed at casing friction-limited rates; consequently, we have little information concerning the ultimate productivity of large diameter bore holes. The most productive well to date has been the Cerro Prieto Field Well No. M-8, which flowed two million pounds of steam and brine per hour during a blowout which was later brought under control. Flow at this rate stressed the sandstone around the bore hole and the well produced excessive amounts of sand. Numerous wells in this field are producing at 1,200,000 pounds per hour. However, 16-20 inch diameter wells might produce between 2-4 million pounds per hour. It is probable, therefore, that average well productivity will be at least in the 1,000,000 to 1,500,000 pounds per hour range. Total life of a well is currently unknown but will probably be at least five to ten years in the Mexican steam field. Silica scale is laid down inside the well bore where some of the brine flashes to steam. Mexican experience shows that this scale can be readily removed by mechanically reaming the well once or twice per year. The silica scale laid down in the Imperial Irrigation District Well No. 1 in the Buttes area is worth about $1000 per ton for its silver content. It is premature at this time to predict any economic mineral recovery from the geothermal brines, but there has been considerable interest at the Buttes field by a number of companies. A small amount of calcium chloride is now produced commercially by the Chloride Products Co. However, to a very large extent the future promise of mineral recovery depends on supporting the cost of the wells from the sale of steam and the heat and water of the brines. Minerals and metals, also, appear to be primarily by-products when one considers the quantities of salts coproduced with a million acre-ft per year of brine. Large scale sulfur recovery may be feasible from a Mexican type of brine which contains about a quarter of a percent of hydrogen sulfide in the carbon dioxide gas that is the main non-condensable gas in the steam.

All evidence to date suggests that both the Buttes and Mexican fields have single phase brine reservoirs and that steam forms by flashing in the well bores. The evidence in the Mexican steam field is somewhat ambiguous. The majority of the wells in Mexico clearly tap a hot brine, but recent drilling has yielded a well with 1500 psi shut in pressure suggestive of penetration into a gas reservoir. Normal flowing pressures are 200-400 psi and steam and brine temperatures range from 400-600°F depending on the pressure drop. A detailed review of the thermodynamics of the Buttes field has been published by Helgeson (1968). The majority of the Mexican data are unpublished but considerable information is available on request.

This type of information is needed for each of the potential U.S. fields in the Imperial Valley in order that the economics of their exploitation can be evaluated.

5.6 Economics of wells

Only approximate figures can be presented for well costs but a reasonable estimate is that the average well will be 5000 feet deep. If one uses 13-5/8 inch I.D. casing with 11-3/4 inch liner, which is a minimum figure if the rocks will sustain the resultant flow rate, then the cost per well for well and surface hardware including steam-brine separator and prorated share of gathering line cost is about $100,000.* Well spacing will probably be 500-1000 feet if current experience in the Valley is indicative. Production of 1,000,000 to 1,200,000 pounds of steam and brine per hour appears reasonable. This mixture should have an average recoverable enthalpy of 500 B.T.U.'s per pound. The wells would, therefore, be producing about 500,000,000 to 600,000,000 B.T.U.'s per hour. If we set a sale price of one cent per 1,000,000 B.T.U.'s, this means a value of $5-6 per hour or $120-144 per day per well. Assuming production for 350 days per year would yield a gross of $42,000-50,000 per year. Assigning approximately half of the gross to operating costs, including royalties, taxes, etc., the wells should pay out in four years or approximately half of their estimated lives. Obviously, a small increase of efficiency or of energy price of even one cent per million B.T.U.'s will have a major favorable impact on the profitability of the steam wells. Some small increment to the base energy price may be necessary to

*This estimate was increased to $200,000 by Rex in correspondence dated 4/6/70.

cover waste brine reinjection costs, but basically the approximate fair cost of geothermal heat in the Imperial Valley is near 1-2 cents per million B.T.U.'s. This compares to 25-35 cents per million B.T.U.'s for fossil fuel heat and 22-25 cents per million B.T.U.'s for the more optimistic nuclear figures. Future nuclear cost projections suggest further declines, but there is no nuclear heat source on the horizon anywhere near the cost of geothermal heat. This does not mean, however, that geothermal steam is clearly competitive with nuclear power for electricity generation. Nuclear steam is dry, high pressure, high temperature steam that can be used very efficiently in large power plants. Imperial Valley geothermal steam is relatively low pressure, low temperature steam, well suited for small power plants but less attractive for large units. Furthermore, it is accompanied by large amounts of hot brine which must be utilized to make the entire venture economic. Consequently, geothermal energy in the Imperial Valley offers its greatest potential for a combined desalination-power program.

Industrial uses for low cost process steam are numerous and it is not feasible to enumerate them here but one possibility might be production of deuterium using preliminary solar concentration followed by the use of the hydrogen sulfide exchange technique used by DuPont at Savannah River. The low cost of heat in the Imperial Valley might sufficiently drop the cost of heavy water to the point where heavy water reactors could compete with light water reactors with a fuel cost savings by using natural instead of enriched uranium.

Industrial process heat uses, however, face the same problem that faces production of electricity, namely disposal of the coproduced brines. Here again water desalination is the key to brine disposal.

Desalination pilot plant studies of various types of Imperial Valley brines are needed to work out the economics of large scale operations. The pilot plants will each need a few test wells to provide the necessary feed brine. One of the major objectives of the U.C.R. Imperial Valley Project is to provide scientific information to assist in locating, drilling, and testing these initial wells. Research in support of this geothermal desalination effort is being carried out by the Sea Water Conversion Research Laboratory of the University of California at Berkeley under the direction of Dr. Alan Laird.

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