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AN ANALYSIS OF THE POTENTIAL USE OF GEOTHERMAL ENERGY FOR POWER GENERATION ALONG THE TEXAS GULF COAST

A Report Prepared by

The Texas Division of
Dow Chemical, U.S.A.
for the Governor's Energy
Advisory Council
The State of Texas

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A. Summary

Three forms of potential geothermal energy may exist in the State of Texas. These are hot rocks in the Trans Pecos region, convection type geothermal water in the Rio Grande Rift basin, and geopressured geothermal water along the Gulf Coast. Of these, only the geopressured waters have been verified. Exploration wells for oil and gas have established the presence of deep hot water deposits along the coastal area, offshore and inland for 75 miles. These exist in thick shale and sand beds in the geopressured zone. The most favorable area appears to be at depths of 12,000 to 15,000 feet where the temperatures range from 300 to 400°F. The best sand deposits, which are necessary for production, appear to be most numerous in the Brownsville to Corpus Christi coastal zone. The ability of these sand and shale reservoirs to produce the necessary quantities of hot water is controversial but geological evidence plus short time flows from blow-out wells are encouraging.

Indications are that a series of relatively small, 10 to 50 megawatt, power plants could be located along the coastal plain of Texas. These plants could produce at least 20,000 megawatts and possibly as much as 100,000 megawatts under the most favorable conditions. Cost of the power appears to be in the range of 25 to 35 mills per kilowatt hour in 1980 providing the water is saturated with natural gas which could be sold to offset some of the cost. If the gas is present, at least 6 billion cubic feet per day of natural gas would be produced. This estimated power cost is based on highly inflated equipment and drilling expense. In a more realistic economy without shortages, values of 20 mills per kilowatt hour could be obtained.

Unit capital investment as presented here for such plants would exceed projected costs for nuclear or fossil fueled power plants. This fact plus the unproven nature of the reservoirs preclude private development of the resource. However, successful development of a demonstration plant with public funds could establish the viability of geopressured waters as a source of power and natural gas and encourage private investment to exploit this energy source, should it prove competitive with other sources of electric power generation.

B. Background

The need for new energy sources to supplement dwindling reserves of oil and gas in the State of Texas is self-evident. One alternate source of energy to produce electric power is the very heat of the earth itself. This source is generally referred to as geothermal energy.

The upward flow of heat through the mantle of the earth is universal but nature has endowed certain areas much more richly than others. These are primarily spots where the hot magmas of the earth's interior have intruded into the mantle and are relatively close to the surface. Sources of recoverable heat from these intrusions consist of two forms, shallow hot rock formations and sandy sedimentary deposits filled with hot water or steam.

It is proposed that heat may be recovered from the hot rocks by drilling interconnected wells and circulating water through the rock to obtain the heat energy. In the case of the hot water sources, the heat is now being recovered by penetrating the formation and producing steam or hot water-steam mixtures. This type of hot water source has as its origin a hot rock heat source and a normal ground water fluid source such that it is a renewable hot water supply. Thus, it is often termed a convective hot water resource.

A third and significantly different source of the earth's heat occurs in deep subsiding sedimentary basins found in many parts of the world. This source consists of sand and shale bodies filled with highly pressured hot waters trapped in these deposits by various mechanisms eons ago. The waters had as their origin the waters of the sands plus the adsorbed waters of clays which were the forerunners of the shales. These trapped waters with low heat conductivity have acted as blankets to the normal heat flow of the earth and through the years have absorbed heat. As a result, they are now much hotter than normal for the depth of their occurrence. This type of resource is referred to as geopressured geothermal water.

Man has exploited geothermal energy for the production of electric power and for sources of heat to warm his homes and to meet other heat needs for many years. The first electric power was produced in Larderello, Italy, in 1904. This plant utilized a steam source of the convective type with volcanic rocks as the heat reservoir. It is still in operation today, generating over 360 megawatts of power. Convective type hot water systems have been developed for power generation in Japan, New Zealand, Iceland, Mexico and the U.S.S.R. and are under development in many other countries. The only commercial geothermal power production in the U.S. has been from a steam field at The Geysers, north of San Francisco, California. This field is presently producing steam for the generation of 400 megawatts of electricity. Geopressured geothermal waters have been encountered many times in the search for oil and gas. Location and character of these waters are well known but no production or utilization has been attempted.

Estimates of the potential for geothermal power production in the U.S. vary widely. Unfortunately, steam sources such as The Geysers are very rare, so hot waters and hot rocks must constitute the principal resource. Estimates made by Dr. Alfred J. Eggers, Jr.(1), Assistant Director for Research Applications, National Science Foundation, testifying before the U. S. House Subcommittee on Energy of the Committee on Science and Astronautics in September of 1973, placed the steam resources of the U.S. to be of no national consequence in comparison to the total U.S. power production of 391,180 megawatts in 1972. Dr. Eggers estimated the hot water potential as tens of thousands of megawatts and the hot rocks in terms of hundreds of thousands. Significantly, he indicated that as the abundance of each type increases, the difficulty of utilization also increases.

Most investigators tend to overlook the geopressured waters because of the fact that they are depletable in nature. However, as a twenty to fifty year supply, they may constitute the largest source of potential geothermal energy in the U.S. and more than 50% of that potential appears to exist in the State of Texas.

C. Geothermal Resources of Texas

All three types of potential geothermal resources exist in the State of Texas. Figure 1, modified from Myron Dorfman, 1974[2] illustrates the areas of occurrence of geothermal potential in the State. Hot underground rocks are known to exist in the western Trans Pecos area. Little is known about this potential but it is an extension of formations in New Mexico. Exploration of this system is underway in the Jemez Mountains of central New Mexico where the Los Alamos group is drilling test wells. The outcome of these tests is still in doubt but technical difficulties in the extraction of heat from such rocks will involve many years of research and development. Should such be successful, those rocks could become the source of very large amounts of electrical power in the late years of this century.

A second source of geothermal energy is believed to exist in the sedimentary basin of the Rio Grande Rift System. A geological fault or rift roughly follows the path of the Rio Grande River along the western side of the Big Bend area. This fault is a source of heat which is evidenced in the area in the form of numerous very hot springs. Along the course of the river, there are a number of sedimentary basins known as bolsons. These bolsons may contain large amounts of hot water. The system is very similar geologically to the Imperial Valley of California where extensive geothermal development is underway and power is being produced in the Mexican portion of the valley. If the rift system is comparable to that of California, preliminary calculations indicate a potential resource sufficient to generate 10,000 megawatts of power for a 50-year period.[2] Areas of high heat flow at shallow depths have been shown to exist in this area by ERTS-1 satellite infrared photographs and the adjacent location in New Mexico is a known high heat flow area.

Waters from these bolsons will be expected to be of medium to high salinity with mineralization comparable to those of the Imperial Valley and other convective hot water systems. Problems of processing such waters are being studied extensively in the Western United States. Exploration and utilization of this resource in Texas will likely await the results of these current efforts but could begin in the late 1980's.

The largest potential source of geothermal energy in Texas appears to be contained in the geopressured waters along the coast of the Gulf of Mexico. Fortunately the Texas Gulf Coast has been the site of numerous oil and gas fields and, as a result, is the most thoroughly drilled area in the world. Numerous well drillers in search of oil and gas have encountered hot water pockets under very high pressure. This pressure has been considered a great nuisance and has resulted

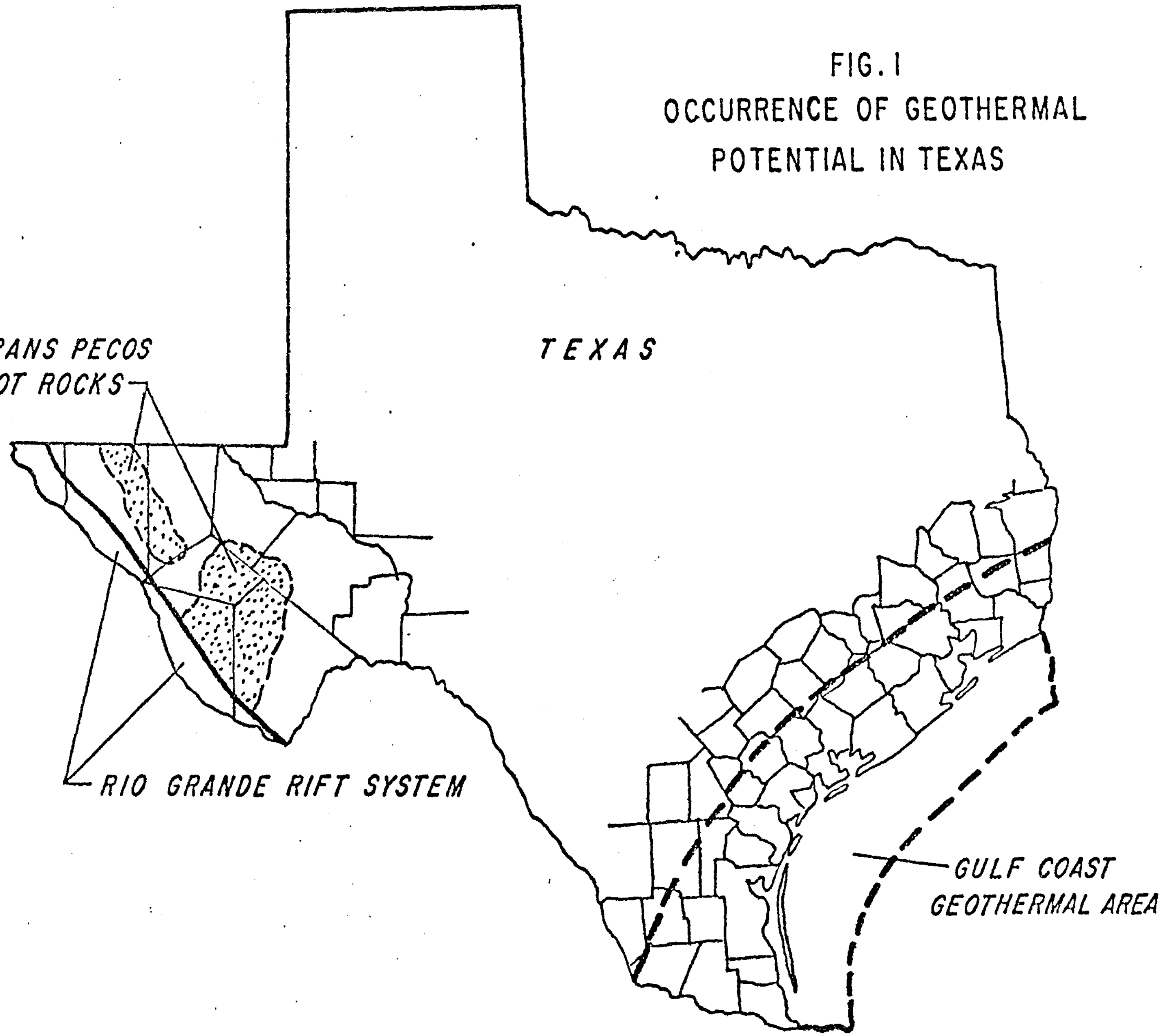


FIG. I
OCCURRENCE OF GEOTHERMAL POTENTIAL IN TEXAS

From Dorfman '74

in many blow-outs and well losses. However, in recent years the technology for drilling wells into these pressure pockets has been developed and considerable gas and oil is now being produced from these formations.

The geopressured zone, as it has been named, is composed of water-filled sands and shales in deep pockets or lenses generally bounded by subsidence faults. Wells drilled from Brownsville to Port Arthur, approximately 75 miles inland and offshore to the extent of drilling, have encountered this high pressure. However, it is not continuous, either horizontally or vertically. Nevertheless, the lenses are widespread and numerous. Depth of encounter may range from as shallow as 3,000 feet to as deep as 20,000 feet and thickness may be several thousand feet. Temperatures of the waters range up to 525°F measured in a 22,000-foot well in Matagorda County and pressures, increasing with depth, may reach 20,000 pounds per square inch. The bulk of the water appears to be in the 325 to 400°F region with 10,000 to 15,000 psi pressure at 12,000 to 16,000-foot depths.

The size and water-producing capabilities of these reservoirs are controversial since no well has been allowed to flow. However, indications are very strong that wells completed properly in thick sands should produce flows possibly as high as 3,000 gallons per minute or 103,000 barrels per day for twenty years. A conservative estimate of 4000 wells at one-half that rate of flow would produce 20,000 megawatts of electric power for twenty years. Verbal estimates of 5 times this amount, or 100,000 megawatts, have been expressed. This does not include offshore potential. A realistic figure awaits detailed geological investigation and test production.

Incentive to investigate this resource is greatly enhanced by the possibility that the waters may contain vast quantities of dissolved natural gas. In fact, these waters plus those of the hydrostatic or non-geopressured region are believed to be the source of the oil and gas found along the Gulf Coast[3,4]. A well producing 1,500 gallons of water per minute may yield up to one million cubic feet of gas per day. This additional value makes these deep waters a geothermal energy possibility even though well cost will be very expensive.

The geopressured waters of the Gulf Coast appear to offer the largest and most available geothermal energy source available in Texas. The remainder of this report will deal with the utilization of this resource.

D. Definition of Geopressured Reservoirs

The geothermal resources of the northern Gulf of Mexico geosynclinal basin differ from those of other known geothermal resources in the source of the waters and the hydrology of the systems. Fluid resources of such a geosynclineal basin are not dependent on recharge and deep circulation of meteoric water but are derived from the sedimentary rocks themselves, and fluid depletion can occur. However, the very large amount of water in storage makes possible a continuing large-scale rate of production.

Abnormally high fluid pressures are found in large areas of the basin,(5) encompassing a belt of about 800 miles length, from northeastern Mexico to the Mississippi Sound, and underlying the coastal region inland for about 50-75 miles and extending offshore an equal or possibly greater distance. The extent of this zone and the average depth to the top portion is shown in Figure 2. This belt was filled by ancestral rivers which denuded the midcontinent of mainly sand and clay sediments, an estimated one-million cubic miles of such sediments having been transported during the past 40-60 million years. The abnormally high pressured regions, or geopressured regions, are not one continuous volume but exist in lenses, blocks, and separated volumes, a result of the particular causative processes.

Many processes could have been involved in the formation of the geopressured zones.(6) In a general sense, any marine region of rapid deposition of sands and clays where the outflow of the buried entrapped waters has been inhibited results in a partitioning of the overburden load such that the contained water bears an abnormal portion of the load and the rock matrix thereby supports less. The inhibition of water loss may be the result of containment by low permeable shales, by the blocking of the outflow from more permeable sands by tectonic activities, by structural changes, by secondary concentration, or other dynamic processes. The deposits, as they grew to massive proportions, kept sliding into the deeper waters of the geosyncline along lines of weakness or normal growth faults and major barriers to the outflow of the waters contained within the slumping sand sections occurred whenever the faulting was such that a shale section became positioned on the updip edge of the sand block. It is generally accepted that the areal continuity and depth of occurrence of the blocked acquifers are thus delimited by the regional normal faults in the section.(7) Some such faults in the lower Rio Grande embayment of south Texas have displacements exceeding one mile and can be traced for 50 miles(8).

It is common in the geopressured zones for the entrapped water to support 0.7 to 0.9 of the overburden weight so

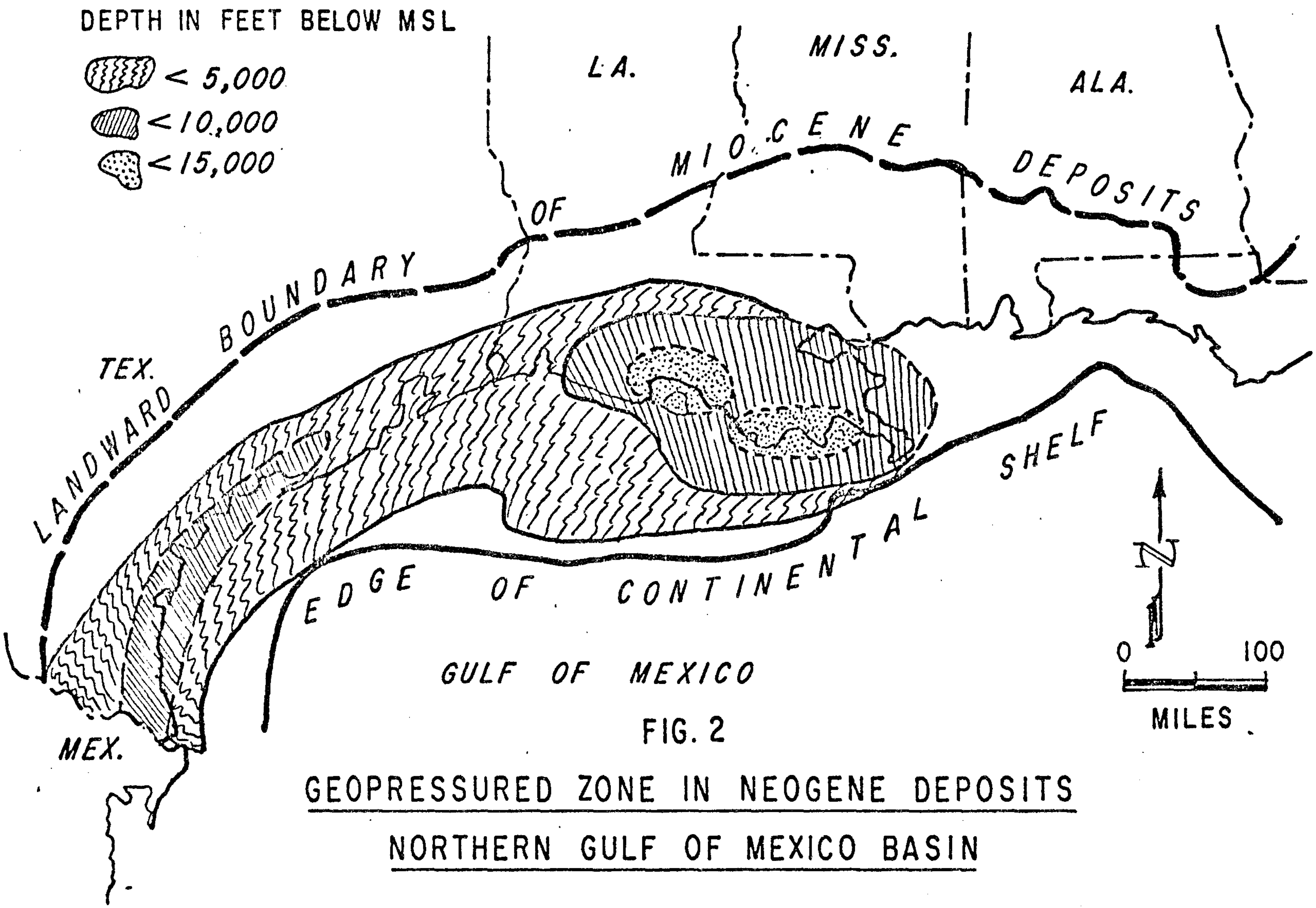


FIG. 2

GEOPRESSURED ZONE IN NEOGENE DEPOSITS
NORTHERN GULF OF MEXICO BASIN

From Jones '69

that the rock matrix is undercompacted. Such zones may be thousands of feet thick and occur at all depths within the sedimentary section; sometimes the top is as shallow as 2,000 feet below the surface. Waters in the geopressured sands are commonly more salty than seawater,[9] but zones of almost potable water do exist.[10] Where conditions were such that water was produced from the shales and where there are adequate contact surfaces between the sands and the shales, the original brines within the sand volumes have become diluted by fresher waters from the shales.

Because water is a poor conductor of heat and there is so much inert water contained in the under-compacted sedimentary rocks, the geopressured zones store geothermal heat. The resulting rise in temperature may indeed have further aided the sealing of the zone because of thermally induced changes in the sands and shales, especially in the shales immediately above the contained sands.

The temperature distribution along the Gulf Coast is illustrated in Figure 3 which shows the depth required to reach 250°F or 120°C. A particularly favorable area is located between Brownsville and Corpus Christi. The depth to 150° or 302°F in this area is shown in Figure 4.

Another potential source of energy is the methane gas which is almost always found in solution in geopressured waters.[11] The estimated amounts vary between 10 and 40 standard cubic feet of gas per barrel of water[6, 12], a not inconsequential potential source of energy.

Thus, the energy resource base of the geopressured waters consists of three parts: the sensible heat of the waters, the dissolved gases, and the mechanical energy of the high pressure fluid. A second resource may be possible in some reservoirs in the form of waters sufficiently fresh to be used directly as agricultural or industrial water. These cases will likely be rare but may exist in south Texas. Normal desalination methods may, of course, be used to obtain useable waters from the waste streams.

The sand and shale bodies in the geopressured regions of the Gulf Coast are known to contain highly pressured hot waters with large amounts of methane gas in solution, but there is no known history of such water production. The thousands of bore holes which have penetrated the geopressured zones of the Gulf Coast were drilled for hydrocarbons and over-pressured waters encountered were looked on as a danger to be fought. Thus, although the subsurface geology has been ascertained as well as in any area of the world by direct penetration and logging, the characteristics of the water reservoirs were not studied, and the essential information

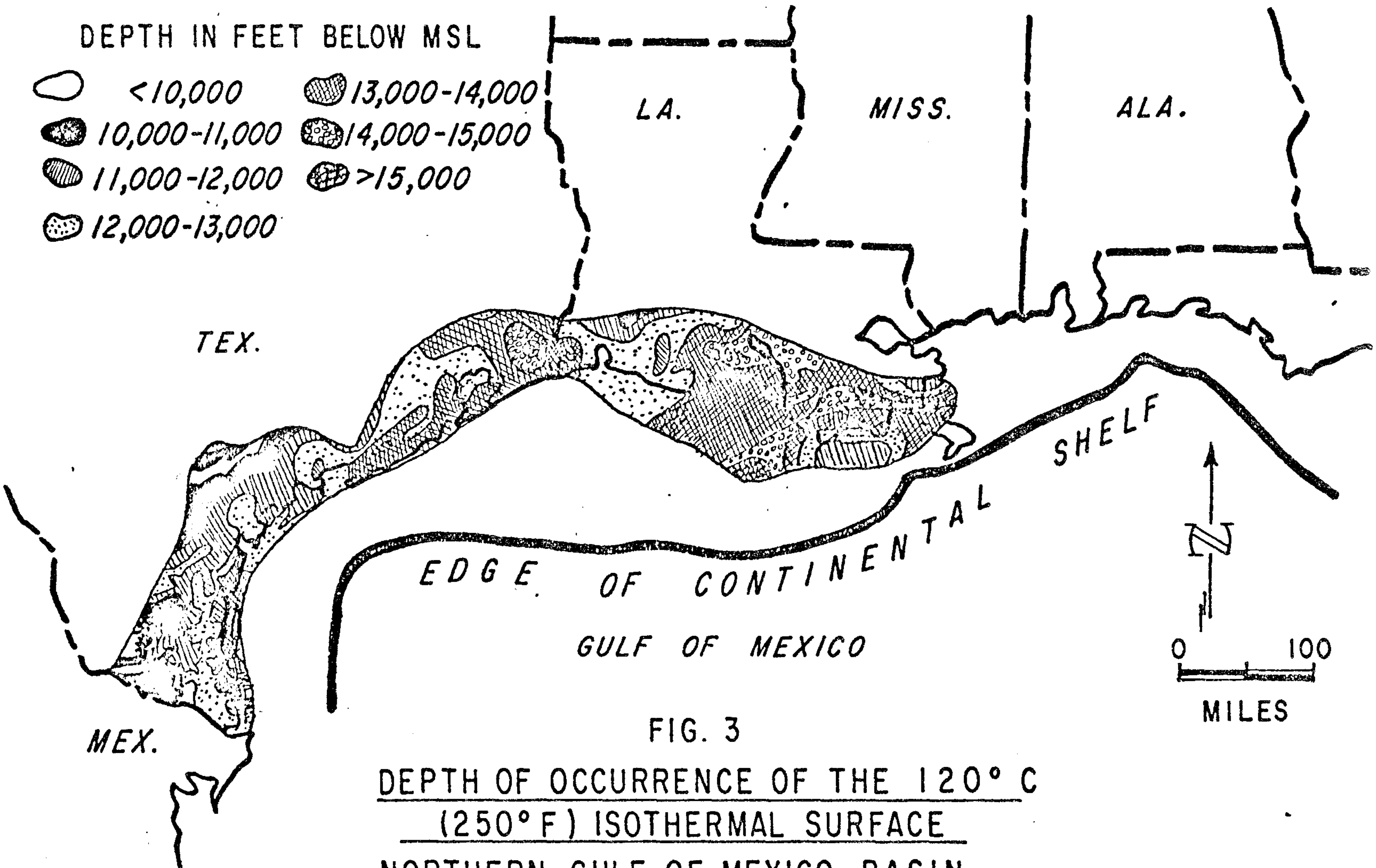


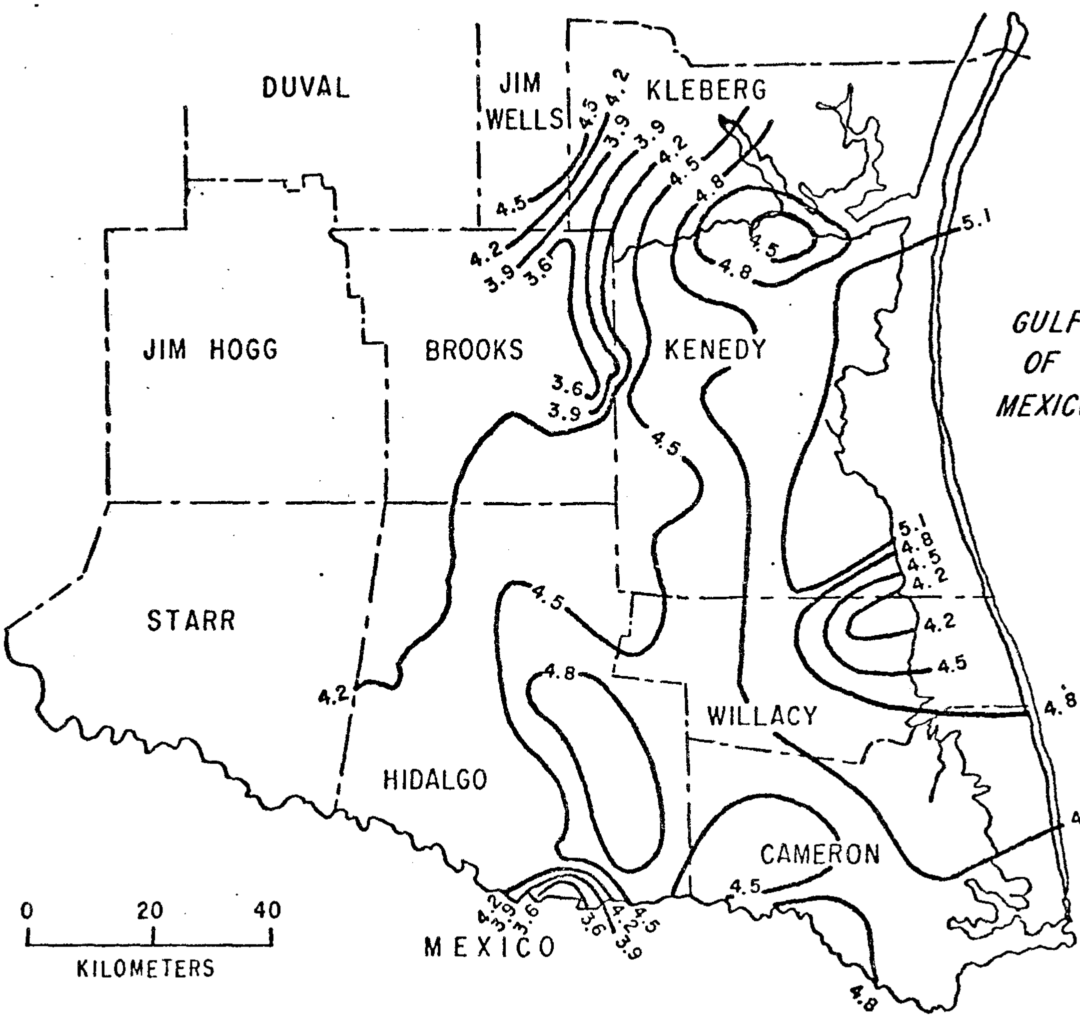
FIG. 3

DEPTH OF OCCURRENCE OF THE 120° C
(250° F) ISOTHERMAL SURFACE
NORTHERN GULF OF MEXICO BASIN

From JONES '70

Fig. 4 – DEPTH OF OCCURRENCE OF THE 150° (302°F) ISOTHERMAL SURFACE IN THE SOUTH TEXAS COASTAL PLAIN.

EXPLANATION—3.9— LINE OF EQUAL DEPTH OF 150° C ISOTHERMAL SURFACE INTERVAL 0.3 KILOMETER DATUM IS LAND SURFACE



FROM JONES '69

required to establish the economic feasibility of large-scale water production--the temperatures of the waters, the salinities, the amount of dissolved gases, and, of greatest importance, the size of the reservoir--must be obtained from available oil field data and the general geological knowledge developed by the petroleum-oriented geologists. Abnormally high temperatures have been observed; dissolved gases are almost always present in the geopressured waters; what is lacking is secure information on the reservoir size and production capability of the geopressured water zones which were penetrated during the development of the oil and gas fields. It is of interest, however, to estimate the productivity of some possible reservoirs in the lower Rio Grande Embayment region using reservoir parameters derived from our best knowledge of the local conditions. The areal dimensions of the models are derived from the best geological knowledge available, assuming that the reservoirs are limited by the major faults or structural features; the physical parameters are those obtained from well logs. The calculations are of accumulated water production and are based on methods developed for flow problems in fluid reservoirs which are in general use in the petroleum industry.[13] The case for single well production only is treated.

Model 1. Data obtained from Geological Section, Oil and Gas Division, Dow Chemical, U.S.A. Average values for Hidalgo County, Texas;

Dimensions	7 X 16 miles
Net Sand Thickness	500 feet
Permeability	0.100 darcy
Porosity	25%
Viscosity	0.2 centipoise
Average compressibility of water & rock pore space	9 X 10^{-6} volume/volume/psi
Well radius	0.3 feet

The results of the accumulative production calculations for several values of the bottom hole drawn-down pressure are given in Figure 5. The driving pressure is assumed to be held constant in these calculations. The rate of production thus decreases with time. In production, a constant water supply would be required. Therefore, it is desirable to calculate the total available water from the reservoir. Table I shows the results of this calculation. A uniform production rate figure can be calculated from these values. Other models were also calculated in the same manner.

Figure 5

CUMULATIVE WATER YIELD
AT VARIOUS DRAW-DOWN PRESSURES

7 x 16 miles x 500-ft. sand Hidalgo County Model

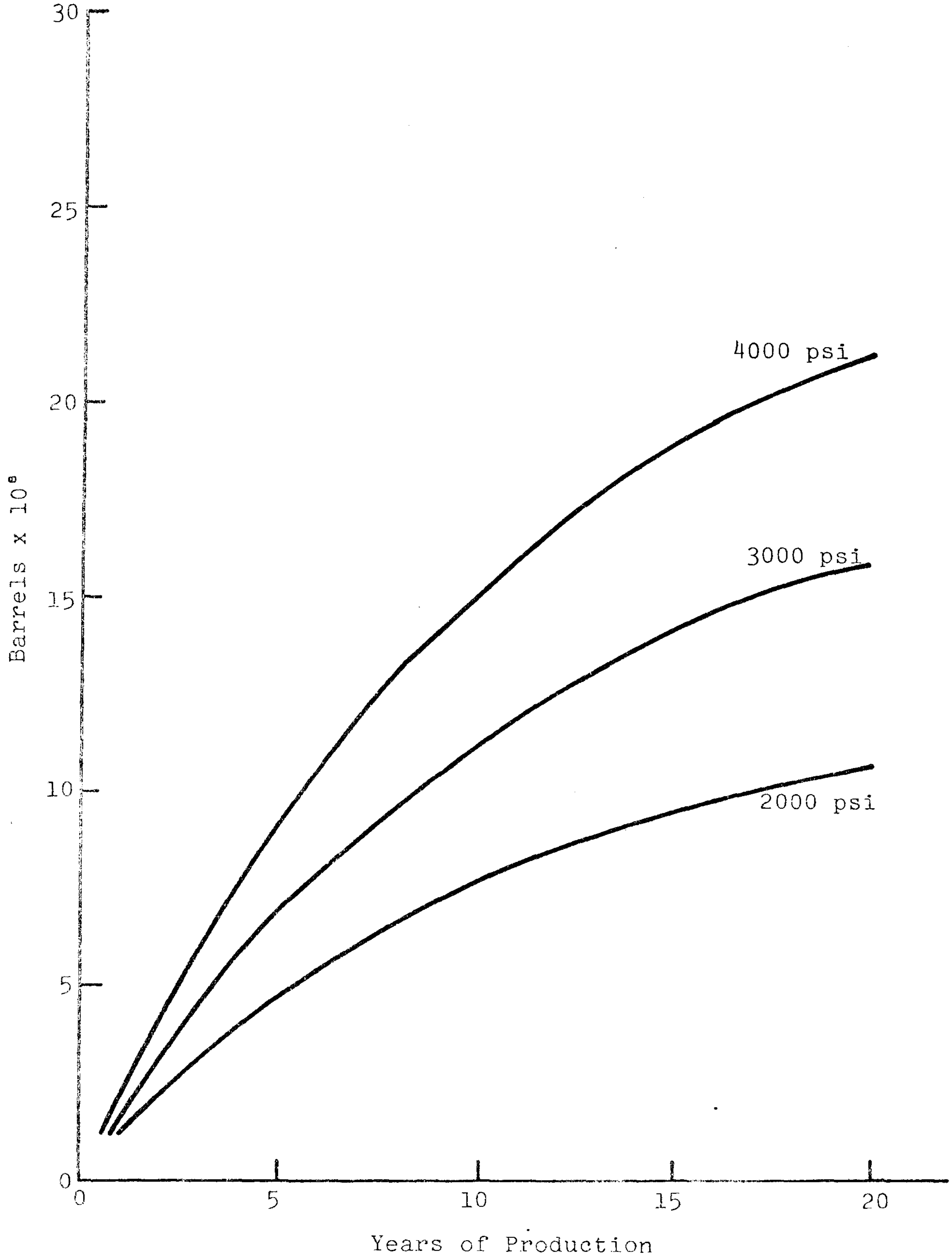


Table I

TOTAL AVAILABLE WATER
HIDALGO COUNTY MODEL

Draw-down Pressure, psi	Total bbls x 10^9	Available In 20-Year Period bbls x 10^9
2,000	1.25	1.07
3,000	1.88	1.60
4,000	2.50	2.13

Model 2. Data obtained from Dr. P. H. Jones, Hydrologist, Gulf Coast Hydroscience Center of the U. S. Geological Survey. Values are mean of average range for lower Rio Grande Embayment of south Texas. Two models based on this data were investigated: one with an assumed permeability of 0.0275 darcy and the second with an assumed permeability of 0.08 darcy.

Dimensions	10 X 50 miles
Net Sand Thickness	1,000 feet
Porosity	18%
Average water and rock pore compressibility	9 X 10^{-6} volume/volume/psi
Viscosity	0.2 centipoise
Well radius	0.3 feet
Permeability 1)	0.0275 darcy
2)	0.08 darcy

Figures 6 and 7 are the curves of cumulative production as calculated for the two cases of this model for the driving pressures indicated.

It is of interest to compare the parameters of the models considered in this study with those considered by E. Herrin(14) in his study of the geothermal potential of the lower Texas coastal region. He developed models for two sites as shown in Table II.

These models compare very favorable with those developed and calculated in this report. Total available water from the Jones Models 1 and 2 are listed in Table III.

These calculations indicate geopressured reservoirs are capable of producing the quantities of water necessary for the operation of power plants. It is interesting to note that the assumed reservoir dimensions based on known fault blocks are in agreement with calculated sizes from depleted water drive geopressured gas reservoirs. An example in point is a gas sand at Lake Arthur where actual gas produced indicated a region 20 by 7 miles required to produce the water to replace the gas.(15)

The calculations in this section are all based upon compressibility of water and collapse of the structure sand only. Considerable evidence is available which indicates that water from the surrounding shale will feed into the sand as production takes place.(6, 16, 17, 18 & 19) In that case, the recoverable water could be considerably greater than these calculations show. This additional water could increase well flow, lengthen producing life, and improve economics.

Figure 6

CUMULATIVE WATER YIELD
AT VARIOUS DRAW-DOWN PRESSURES

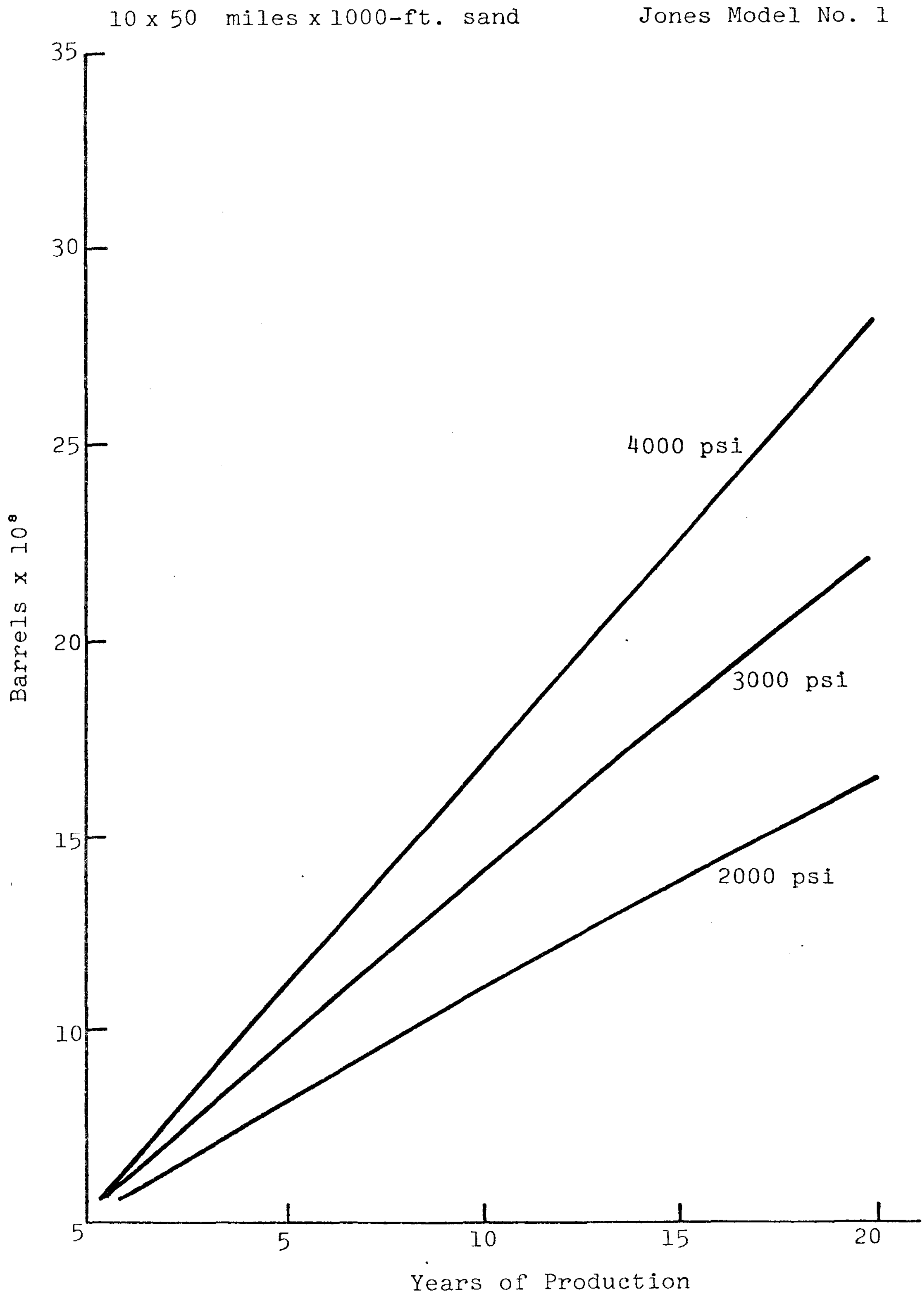


Figure 7

CUMULATIVE WATER YIELD
AT VARIOUS DRAW-DOWN PRESSURES

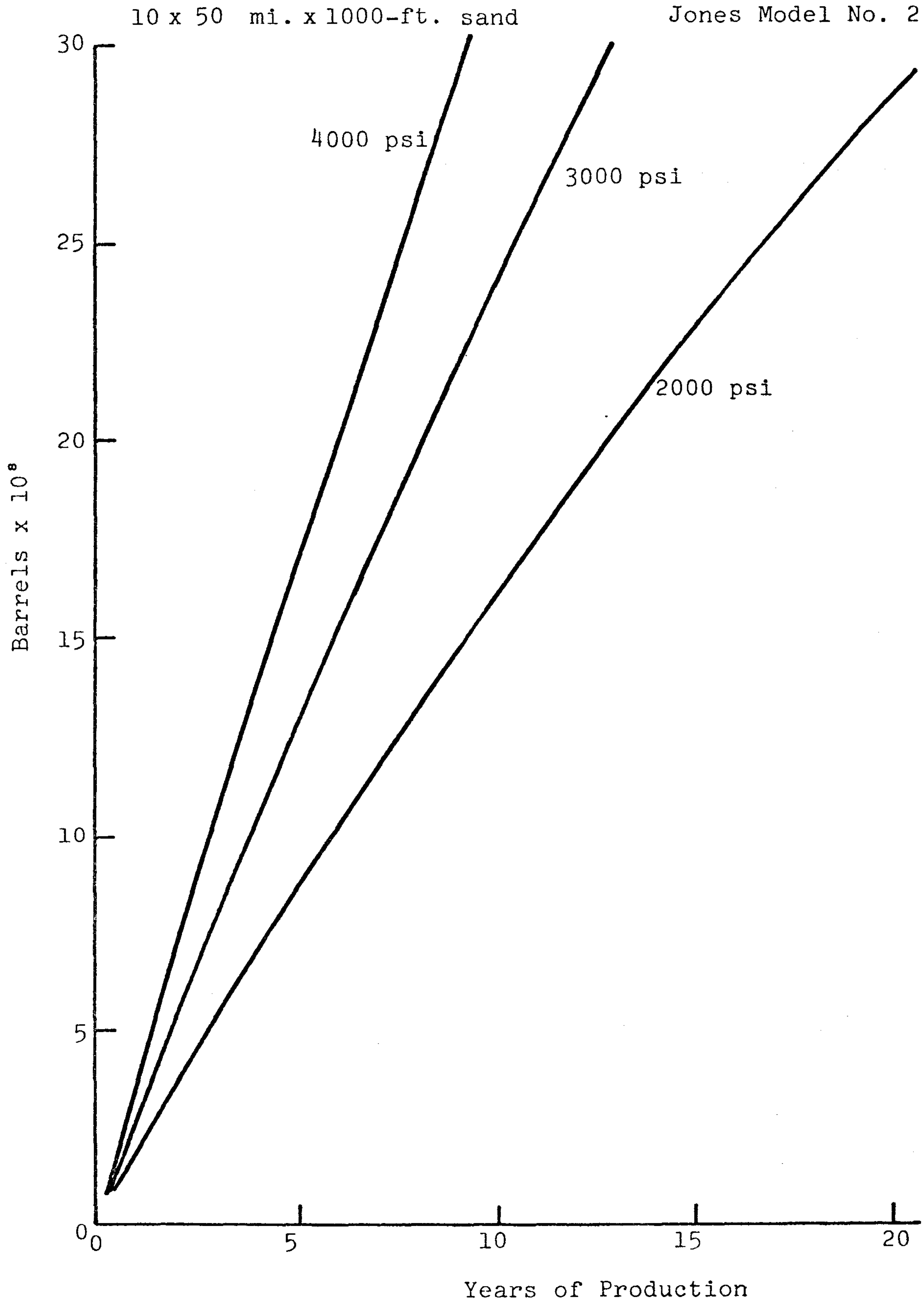


Table II

LOWER TEXAS COASTAL SITES
DEVELOPED BY E. HERRON

	Sebastian Site	Port Mansfield Site
Depth to top of Geopressure	14,300 feet	12,650 - 15,660 feet
Average pressure gradient	0.81	0.79 - 0.91
Area	At least, 10 X 30 miles	At least, 10 X 30 miles
Net Sand Thickness	700 feet	800 feet
Porosity	20%	20%
Permeability	100 - 135 millidarcies	100 - 135 millidarcies

Table III

TOTAL AVAILABLE WATER
JONES MODELS 1 AND 2

Draw-down Pressure (psi)	Total Available (bbls X 10^9) Rio Grande No. 1	Total Available (bbls X 10^9) Rio Grande No. 2	Available 20-Yr Period (bbls X 10^9) Rio Grande No. 1	Available 20-Yr Period (bbls X 10^9) Rio Grande No. 2
2000	8.04	(same	1.15	2.89
3000	12.1	(as	1.72	4.34
4000	16.1	(No. 1)	2.29	5.78

E. Geopressured Well Technology

The technology of drilling wells into the geopressured zone has been well developed in the search for oil and gas. It is beyond the scope of this report to detail the various procedures used to signal the approach to abnormal pressure and the precautions taken to avoid blowout or loss of circulation. Stuart[15] gives an excellent general description of the problems and the techniques used to avoid trouble. In the late 1950's, drilling troubles led to an "impenetrables" clause in Gulf Coast drilling which relieved the contractor of further obligation if excessive problems developed. In the 1960's, a great deal of understanding of the geopressure zone was developed. This new knowledge led to improved drilling technology and wells can now be drilled into geopressure and completed both onshore and offshore with a high degree of assurance.

One area which may present a problem is well completion. Present technology is centered upon completion of oil and gas wells. The volume of flow for water wells will be much greater so refinement of completion techniques will be necessary. However, it is anticipated that technology for completion of water wells in hydropressure may be combined with oil well geopressure technology to provide the necessary information.

In respect to technology, it should be noted that the drilling techniques for drilling geopressured geothermal water wells are probably more advanced than those for normal convective hot water systems. These later wells present problems[20] that are only now being grappled with.

F. Present Geothermal Process Technology

Geothermal, geopressured water along the Texas Gulf Coast contains three forms of energy capable of utilization through known technology:

- Thermal
- Kinetic
- Dissolved Methane

They can be harnessed to produce heat and electric power, as well as feedstock for the chemical industry. However, as with the conversion of many forms of potential energy to readily useable forms, special problems exist requiring some development work and unique solutions. Geothermal water is not without these problem areas.

1. Production of power from thermal energy

Geothermal water, as with all hot waters, can be used directly as a heat source in the warming of buildings and for some other direct heating uses. However, the distance to which such heat can be transmitted economically is quite limited. The generation of electric power produces a form of energy capable of widespread, economical distribution and utilization for many purposes. Because of its many favorable characteristics and wide acceptance, geothermal energy will most likely be used principally for the generation of electric power. This can be done by two methods:

- Flashing steam from the geothermal water by reducing the pressure to a predetermined point and passing the steam through a low-pressure expansion turbine connected to an electric generator.
- Transferring heat from the geothermal water to a suitable secondary fluid which is, as a result, vaporized and passed through an expansion turbine connected to an electric generator.

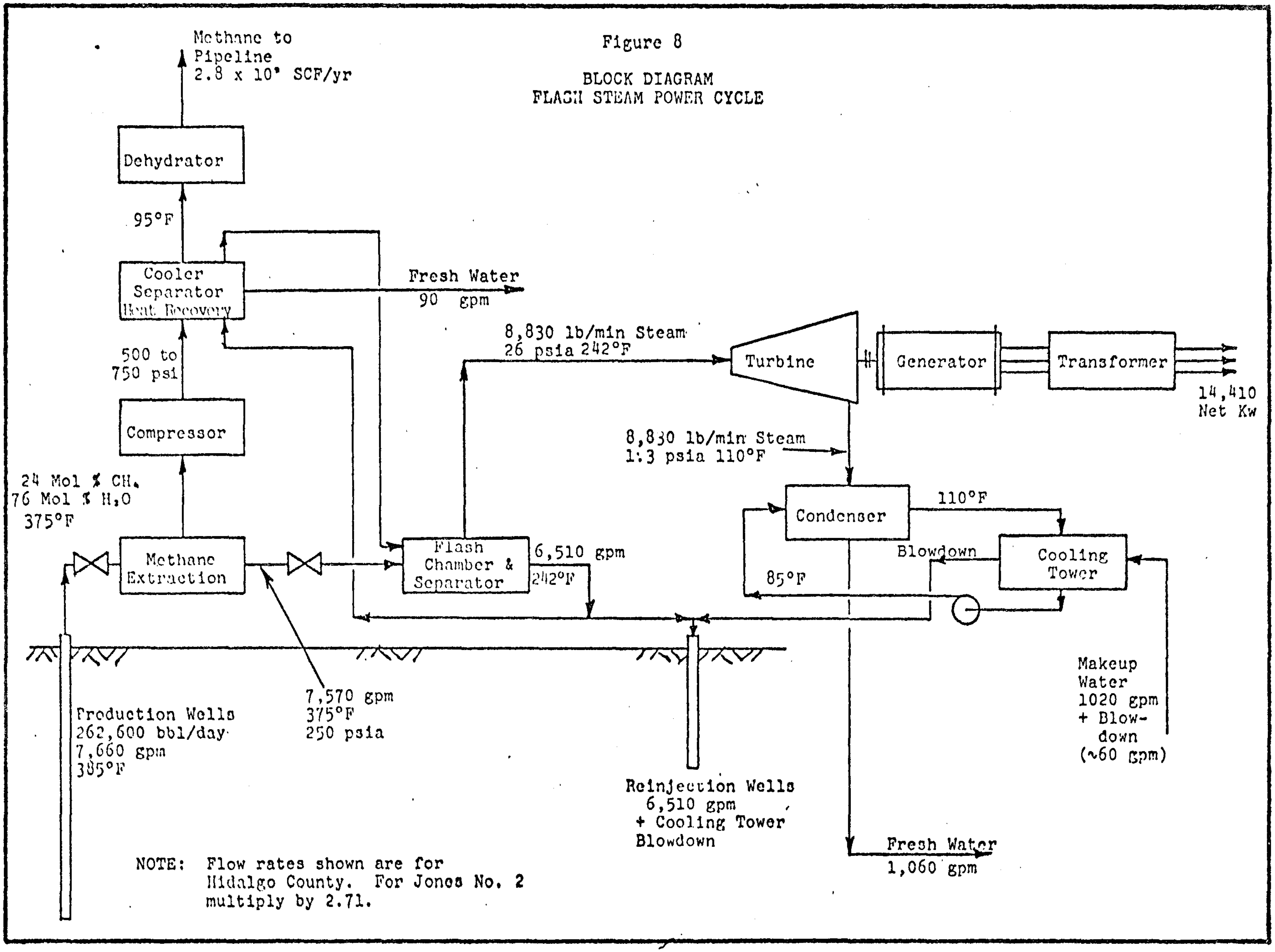
Other methods have been proposed. At least one, a "hot steam" expansion turbine or total flow system, is presently in the development stage.(11) Its proponents claim a substantially greater efficiency potential than with the flashed steam or the secondary fluid process. This remains to be demonstrated.

a. Flash Steam Process

A proposed flow diagram for a single-stage flash steam process is shown in Figure 8.

Figure 8

BLOCK DIAGRAM
FLASH STEAM POWER CYCLE



NOTE: Flow rates shown are for Hidalgo County. For Jones No. 2 multiply by 2.71.

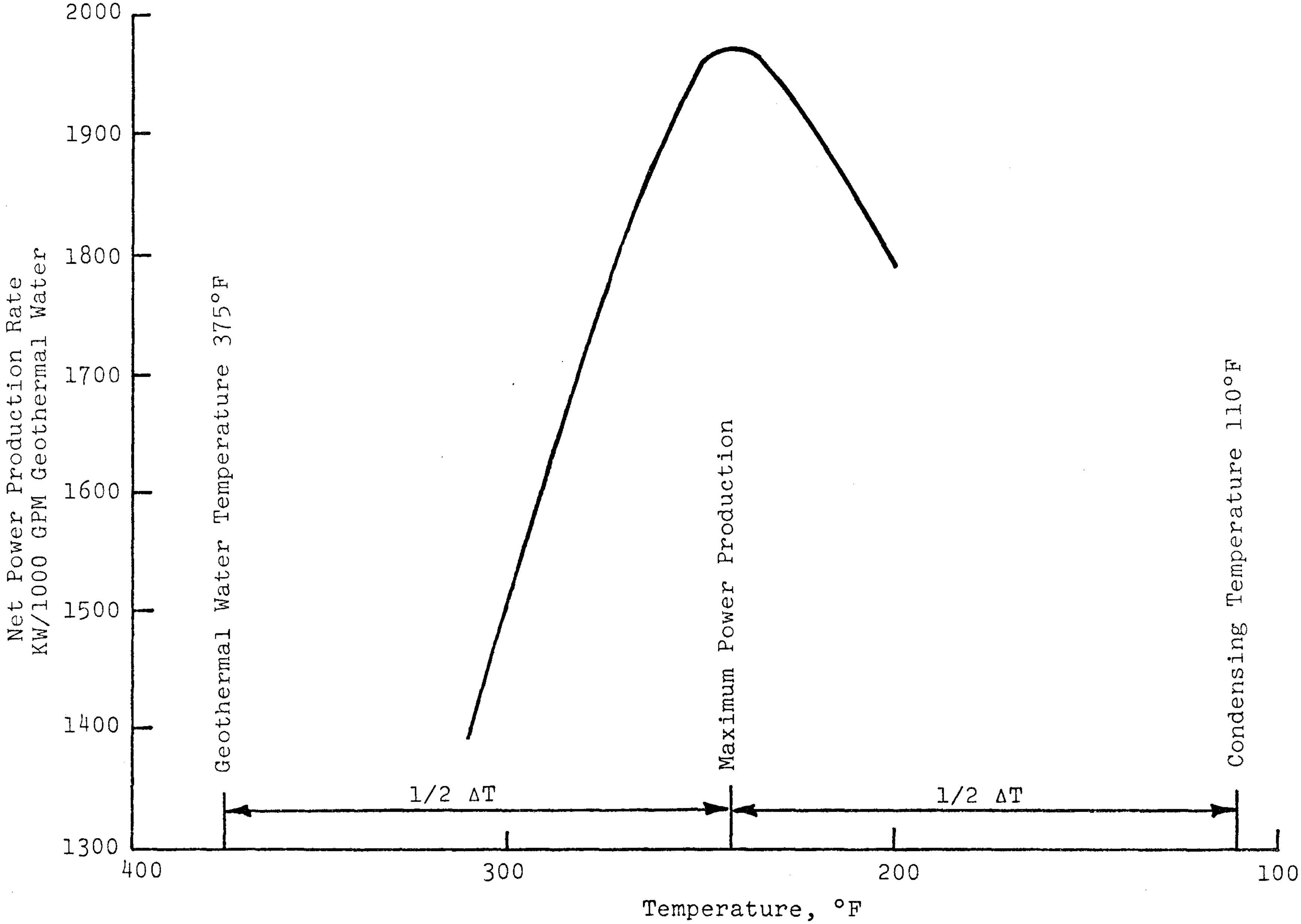
Production well technology for oil and gas is well established. Some special techniques may be required because of the nature of the geothermal, geopressured water. These will be discussed in another section of this report. It is conservatively estimated that a 15,000-foot deep well with 7-inch casing can produce 51,000 barrels per day (1,500 gallons per minute). With a wellhead water temperature of 385°F, the water from each well should be capable of furnishing sufficient energy for the generation of approximately 2,900 net kilowatts of electricity by single-stage flash and 4,900 net kilowatts by two-stage flash. Wellhead shutoff pressures should approximate 5,000 pounds per square inch with a geostatic ratio of 0.8. Well spacing has been taken at 300 feet.

Methane extraction can be accomplished in a straightforward manner by flowing the geopressured water at greatly reduced pressure into a closed vessel. For 385°F water, the pressure in the vessel must be maintained at from 220 to 250 psi, somewhat above the boiling point pressure for water at the geothermal water temperature so that excessive water vapor will not flash. The methane-water vapor mixture will contain 76 mol percent of water vapor. Assuming the methane content of the geothermal water at 30 standard cubic feet per barrel, the latent heat required to vaporize the resulting water vapor will reduce the temperature of the geothermal water by 10°F, or to a temperature of 375°F. The technology for the separation of a dissolved gas in water by reduction of pressure is well known.

The geothermal water with most of the methane removed will then be passed into a flash chamber and separator in which a portion of this water is flashed directly into steam by reduction of pressure. The pressure in the flash chamber must be maintained at a predetermined level. Calculations have shown that the maximum power production by single-stage flash is attained by holding the temperature of the flashed steam at the midpoint between the incoming geothermal water temperature and the condensing temperature of the water vapor leaving the expansion turbine. For an incoming geothermal water temperature of 375°F and a condensing temperature of 110°F, the midpoint temperature is 242.5°F. This corresponds to a boiling point pressure of 26 pounds per square inch absolute (psia). The relationship between power production and single-stage flashed steam temperature is shown graphically in Figure 9. With two-stage flash, the optimum flash temperatures

Figure 9

RELATIONSHIP BETWEEN POWER PRODUCTION
AND FLASHED STEAM TEMPERATURE
(Isentropic Efficiency = 60%)



fall at about the one-third and two-thirds points between incoming geothermal water temperature and condensing temperature. For the assumed conditions, the first flash would occur at 287°F, 55 psia, and the second flash at 199°F, 11 psia. In order to maintain pressure drop in the steam to a minimum as it passes from the flash chamber to the expansion turbine, a simple mesh-type separator is proposed to remove the entrained moisture. Under the assumed conditions, 0.145 pounds of steam will be generated for each pound of geothermal water for single flash and 0.182 pounds for two-stage flash.

Saturated steam at the respective pressures will be passed through expansion turbines for the production of shaft power. At these low pressures, turbine efficiencies will probably be about 60 percent. Actual cycle efficiency under these conditions and a condensing temperature of 110°F has been calculated at 10.7 percent for single-stage flash and 13.4 percent for two-stage flash. Actual overall efficiency, after making allowance for power requirements for auxiliary equipment, has been calculated at 8.6 percent and 10.7 percent, respectively. The thermodynamic cycle is shown on the temperature-entropy chart in Figure 10. Technology for expansion turbine design, construction, and operation is well known. However, complete units operating at such low inlet pressures on saturated steam have not been built and operated under these conditions, to the best of our knowledge. Design studies have been made on very low pressure steam turbines by at least one experienced turbine manufacturer. These have been used as the basis for turbine efficiencies and costing. Because of the very low pressures, the turbines are large in size for the power generated compared with conventional steam plant turbines.

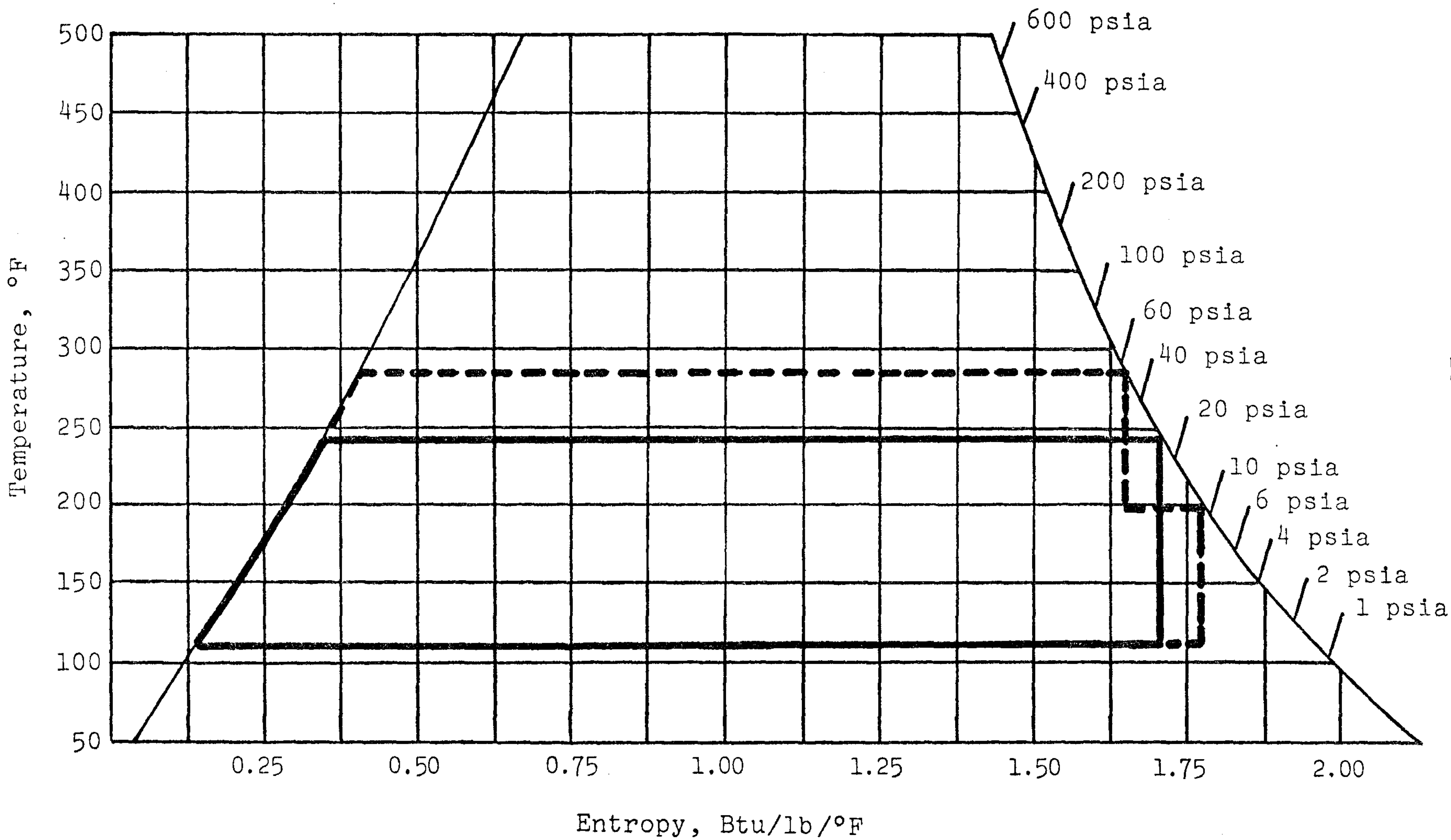
An electrical generator connected to each turbine will be used for the generation of electric power. These generators are conventional units of proven design and performance.

The electric power voltage will be stepped up to distribution voltage by a transformer of conventional design.

Exhaust steam from the turbine will be condensed in a shell-and-tube condenser of conventional design. The condensate will be pure water and can be sold as domestic water to a nearby consumer such as a municipality.

Figure 10

TEMPERATURE - ENTROPY CHART
FOR STEAM



The associated cooling tower will also be of conventional design and construction.

Return wells will be used for disposing of blowdown from the cooling tower and geothermal water at the flashed steam temperature from the steam flash chamber. These wells, with 7-inch casing, will discharge into a suitable receiving formation, probably about 6,000 feet deep. It is not anticipated that pumping or silica removal will be required. Each well should handle about 1,500 gallons per minute. It is estimated that one out of each three drilling attempts for production wells will result in a dry hole. These will be blocked off at the 6,000-foot depth and used as return wells. As with the production wells, spacing has been taken at 300 feet between wells.

Methane and water vapor from the methane extraction unit will be compressed to from 500 to 750 pounds per square inch in a standard compressor.

The methane-water vapor mixture will be cooled to 95°F and the resulting condensed water will be separated from the methane gas by gravity. This will all be accomplished in a cooler-separator-heat recovery unit which is essentially a shell-and-tube heat exchanger. All of the latent heat of the water vapor and some of the heat of the condensate and of the methane can be recovered and returned to the flash chamber for generation of steam. Perhaps 80 percent of the heat can be recovered in this manner. The other 20 percent will be removed in the cooling tower.

Methane gas from the cooler-separator-heat recovery unit will then be dried in a dehydrator. This will be an ethylene glycol scrubber unit with a reboiler for removing the water picked up by the ethylene glycol. This will be conventional equipment as used for drying natural gas.

From the dehydrator, the methane will be piped to its destination through a steel pipeline similar to conventional natural gas lines.

b. Secondary fluid process

A proposed flow diagram for the secondary fluid process is shown in Figure 11.

This process differs from the flash steam process in that the geothermal water leaving the methane extraction unit gives up heat to the secondary

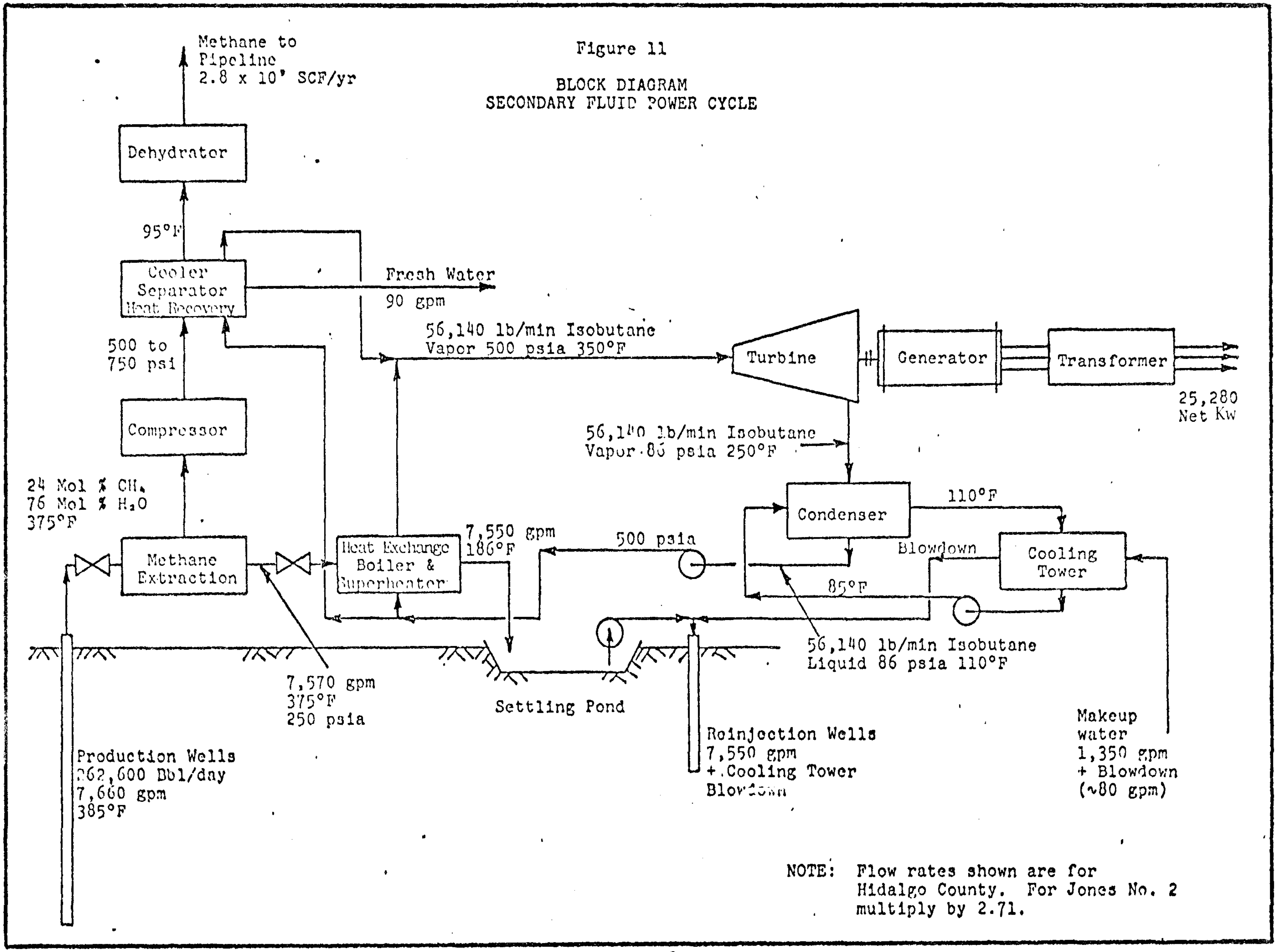


Figure 11
BLOCK DIAGRAM
SECONDARY FLUID POWER CYCLE
Methane to Pipeline 2.8 x 10' SCF/yr
Dehydrator
95°F
Cooler Separator Heat Recovery
Fresh Water 90 gpm
500 to 750 psi
Compressor
24 Mol % CH₄ 76 Mol % H₂O 375°F
Methane Extraction
Heat Exchange Boiler & Superheater
56,140 lb/min Isobutane Vapor 500 psia 350°F
Turbine
Generator
Transformer
25,280 Net Kw
56,140 lb/min Isobutane Vapor 86 psia 250°F
Condenser
110°F
Cooling Tower
Blowdown
85°F
7,550 gpm 186°F
500 psia
56,140 lb/min Isobutane Liquid 86 psia 110°F
7,570 gpm 375°F 250 psia
Settling Pond
Production Wells 262,600 Bbl/day 7,660 gpm 385°F
Reinjection Wells 7,550 gpm + Cooling Tower Blowdown
Makeup water 1,350 gpm + Blowdown (~80 gpm)
NOTE: Flow rates shown are for Hidalgo County. For Jones No. 2 multiply by 2.71.

fluid in a heat exchanger boiler and superheater and then passes to a settling pond for removal of silica before being disposed of in a return well. The turbine is of a somewhat different design than the flash steam turbine, being considerably smaller for a given power output. All other equipment shown on the flow diagram is similar to that shown for the flash steam process. Two flash stages may show some increase in available power over one flash. However, the increase will probably be much less than with steam and has not been calculated for this study.

The geothermal water from the methane extraction unit will pass through a shell-and-tube heat exchange boiler and superheater, transferring a portion of its heat to a secondary power fluid. A number of secondary fluids have been proposed, such as isobutane, the Freons, sulfur dioxide, and others. Isobutane has been selected for use in this study because of its generally favorable properties and fairly good efficiency. Some of its favorable properties are:

- Chemical stability
- Compatibility with normal lubricants
- Non-corrosiveness to generally used materials of construction
- Low cost
- Relatively high molecular weight with resulting smaller turbine
- Non-toxicity

One undesirable property is its flammability. However, good plant design can minimize this potential danger to a safe level. Although isobutane appears to be a good fluid for this purpose, other fluids may be found which are superior, particularly in respect to better thermal efficiencies and higher heat transfer coefficients. These two points are of particular importance in view of the fact that the heat exchanger boiler and superheater, and the condenser, are such a large portion of the total estimated capital cost, about 30 percent.

Superheated isobutane vapor from the heat exchange boiler and superheater will be passed through an expansion turbine for the production of shaft power. Turbine efficiencies have been variously estimated at from 75 percent to 85 percent or more. Actual cycle efficiency under the assumed condition of 375°F geothermal water entering the heat exchange boiler and superheater and a condensing temperature of 110°F, and at a turbine efficiency of 80 percent, has been calculated at 13.8 percent. Actual overall efficiency, after making allowance for power requirements for auxiliary equipment, has been calculated at 11.0 percent. The thermodynamic cycle is shown on the pressure-enthalpy chart in Figure 12 and on the temperature-enthalpy chart in Figure 13. It will be noted that the turbine inlet pressure is 500 pounds per square inch absolute (psia) and the outlet pressure 86 psia. Consequently, in-leakage of air is prevented, with its detrimental effects. On the temperature-enthalpy chart the temperature of the 375°F geothermal water leaving the heat exchange boiler and superheater is 186°F. For comparison purposes, a line showing 450°F geothermal water leaving the heat exchange boiler and superheater has also been shown. Water at this temperature will have an amount of heat removed to reduce the temperature to 142°F. The higher the temperature of the incoming geothermal water, the greater is the amount of heat that can be removed and utilized. Turbines operating on higher molecular weight fluids such as isobutane can be made smaller in size and slower in speed for a given power. Small secondary fluid turbines using Freon reportedly have been built and operated in Japan and Russia, but none as yet in this country. It is understood that a unit is to be installed at Mammoth Lake, California, by Southern California Edison Power Company and Magna Power Company under the conditions assumed for this study. The isobutane power cycle can produce approximately twice as much power as can the single-flash steam cycle for a given amount of geothermal water.

Geothermal water leaving the heat exchange boiler at the fairly low temperature of 186°F must have the silica largely removed before disposing of it in a return well. This will be accomplished in a chlorinated polyethylene-lined settling pond with the aid of a suitable flocculant. Settling will be by gravity. The silica must be removed from the pond bottom from time to time.

Figure 12

PRESSURE - ENTHALPY CHART
FOR ISOBUTANE

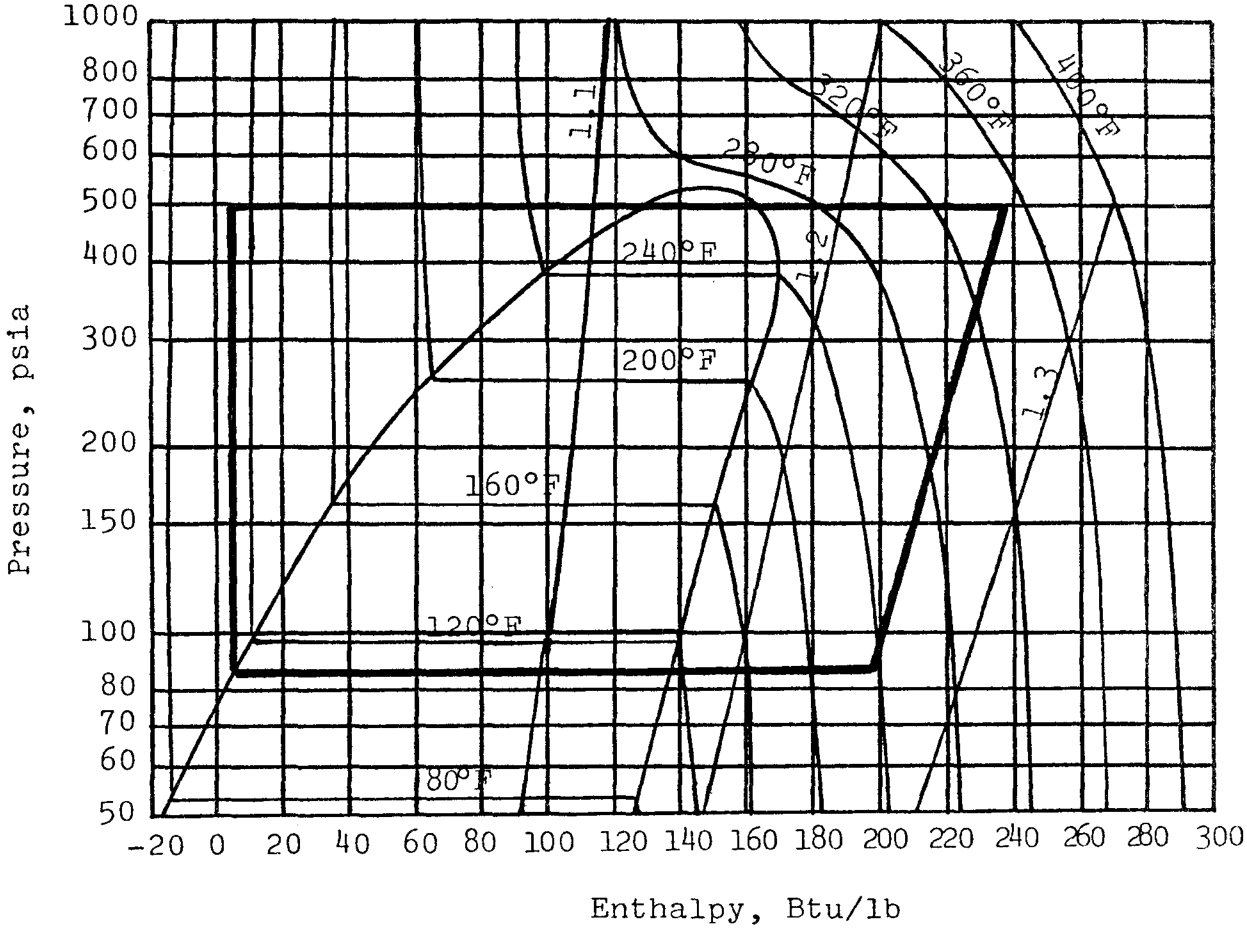
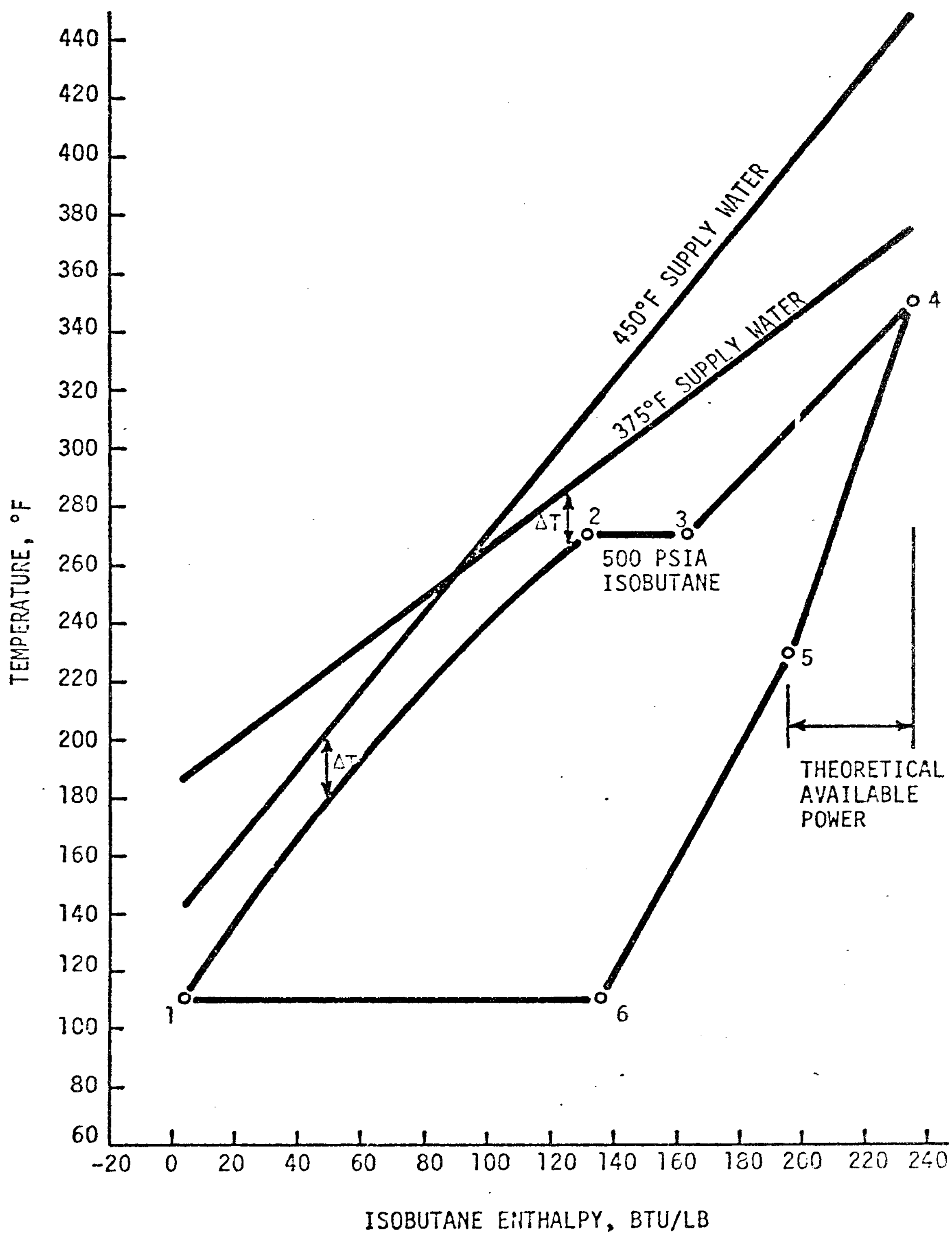


Figure 13

TEMPERATURE-ENTHALPY CHART
FOR ISOBUTANE POWER CYCLE



2. Production of power from kinetic energy

The utilization of the kinetic energy in the geopressured water was investigated, both from a technological as well as an economic standpoint. Technologically, a hydraulic turbine could probably be designed and constructed to produce power. However, several serious difficulties may be encountered.

- Methane removal will take place while the geothermal water is passing through the hydraulic turbine. The very large amount of gas removal could well produce significant design as well as operating problems.
- Entrained sand could cause erosion resulting in considerable maintenance and probably necessitating a standby unit.
- While silica deposition is not expected to occur significantly due to the small temperature drop which will be experienced during the passage of the geothermal water through the turbine, even a small amount of deposition could cause wheel imbalance.

From an economic standpoint, the unit cost of power with any practical combination of thermal and kinetic energy utilization would be, at best, only a little lower than for straight thermal energy utilization. Should a standby kinetic energy unit be required, which is quite likely, even this small advantage in unit power cost would be lessened or eliminated. The utilization of kinetic energy increases the back-pressure on the well, thus reducing proportionately the amount of net driving pressure (ΔP) for producing flow up the well. This is shown in Table IV for varying levels of ΔP used for kinetic energy. It can be readily seen that as greater amounts of ΔP are applied to kinetic energy utilization, the well flow rates and the total power available are drastically reduced. Unit power costs, on a 1980 basis, are only slightly reduced, without a standby unit included. In the interest of energy conservation alone and obtaining the maximum reasonable amount of available power, the utilization of kinetic energy appears to be unsound.

3. Power and water flow relationships

The sustained flow rate of the geothermal water for the desired life of the plant is a direct function of the amount of power that can be produced, other things being equal. For the conditions assumed in this study, the amount of net power which can be generated as a function of the geothermal water flow rate is shown graphically in Figure 14 for the isobutane and steam cycles.

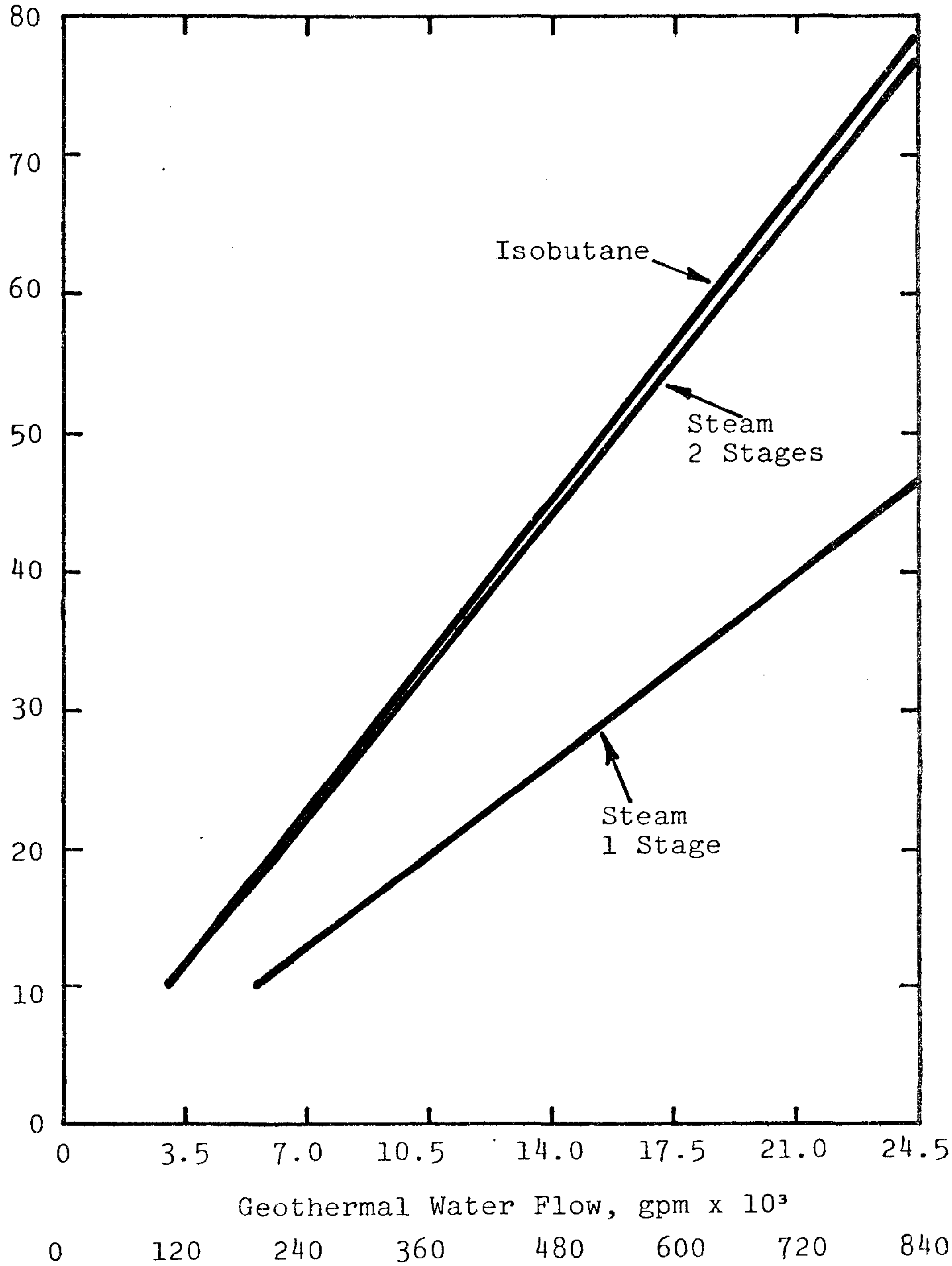
Table IV

POWER FROM VARIOUS COMBINATIONS OF
KINETIC AND THERMAL ENERGY

ΔP Used for Kinetic Energy, psi	Driving Pressure ΔP available for flow after deducting ΔP used for kinetic energy, psi	Flow rate, gpm	Power, Kw			Unit Cost mills/kwh (1980)
			From kinetic energy	From thermal energy, isobutane cycle	Total	
0	3500	7660	0	25,280	25,280	43.4
1000	2500	5470	1830	18,060	19,890	40.4
1500	2000	4370	2190	14,420	16,610	39.1
2000	1500	3290	2190	10,860	13,050	38.0
2500	1000	2190	1830	7,230	9,060	36.0

Figure 14

POWER GENERATION AS A FUNCTION
OF GEOTHERMAL WATER FLOW RATES



Net Power, Mwe

Geothermal Water Flow, gpm x 10^3

Geothermal Water Flow, bbl/day x 10^3

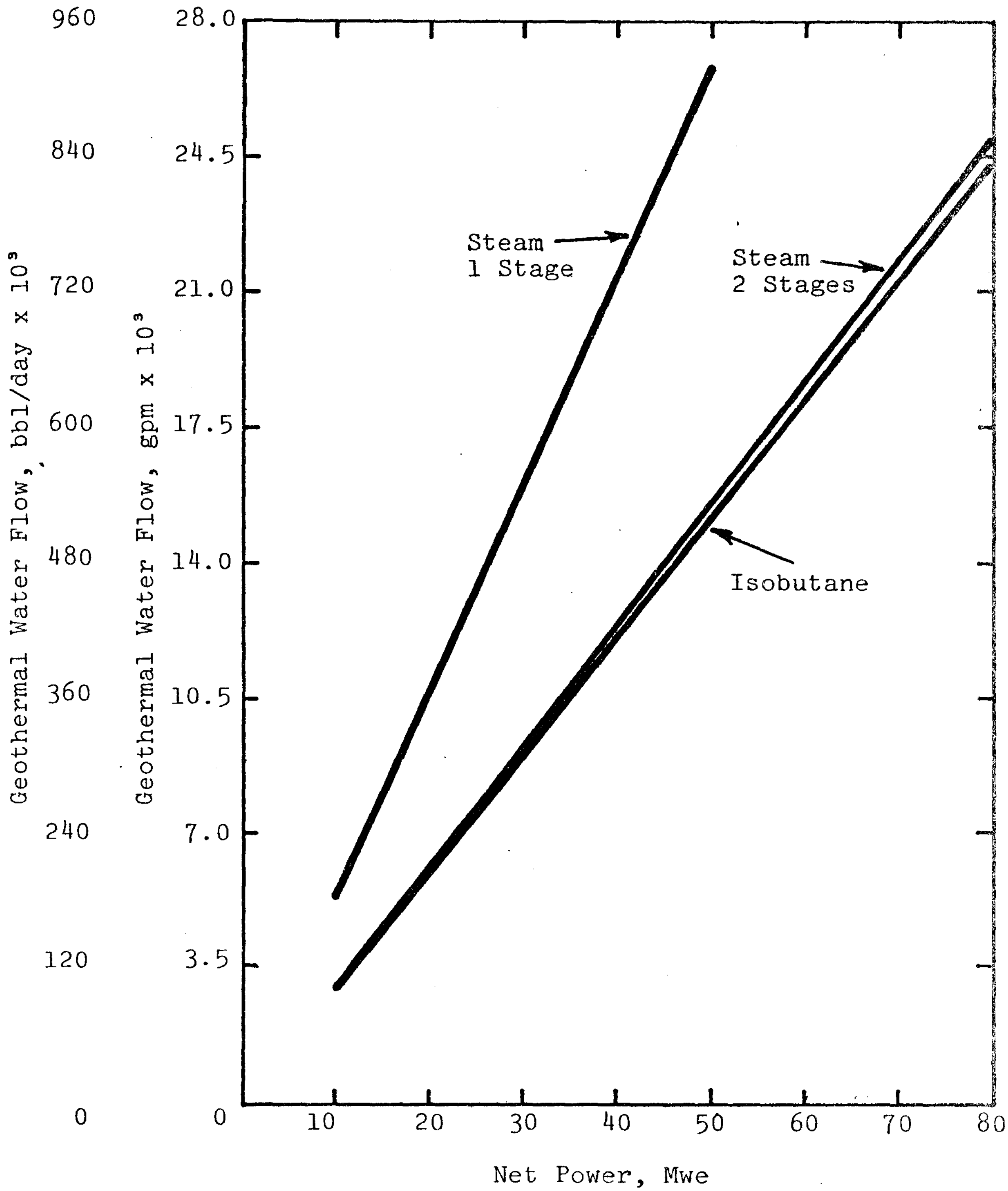
Conversely, the amount of geothermal water required for the generation of a given amount of power is shown graphically in Figure 15.

4. Materials of Construction

Texas Gulf Coast geothermal water should be free of dissolved oxygen and hydrogen sulfide. Because of this, and by preventing leakage of air into the system, carbon steel should be a satisfactory material of construction throughout the plant. Isobutane is also compatible with carbon steel. Cost estimates, therefore, have been based on the use of carbon steel. The only exception to the use of carbon steel would be in the hydraulic turbine, should one be included, where erosion and cavitation due to possible sand entrainment and the extreme turbulence due to high pressures would necessitate use of a harder material.

Figure 15

GEOTHERMAL WATER FLOW RATE AS A
FUNCTION OF POWER GENERATION



G. Economics of Geopressured Geothermal Power Production

Two fields were taken as being representative of goethermal, geopressured water potential along the southern Texas gulf coast. These are the Hidalgo County and the Jones No. 2 models as defined in Section D. The calculated constant geothermal water flow rates of 262,600 bbl/day (7,660 gpm) and 713,100 bbl/day (20,800 gpm) for 20 years from each of the two fields respectively gave a flow rate spread of 2.71 to 1. This was considered sufficient to make valid the extrapolation and interpolation of a series of cost figures based on estimated costs for these two fields, within the range of 10 to 80 megawatts for the isobutane cycle and two-stage steam plants and 10 to 50 megawatts for the single-stage steam cycle plants.

Inflation has been assumed at 5 percent per year. This, of course, is an impossible figure to predict with certainty at this time. Costs have been based on third quarter 1974 prices, with inflation added thereon. For the 1980 cost basis used in this study, it has been assumed that plant and equipment purchases and construction would start in 1978 and be completed in 1980, averaging out, cost wise, in 1979. An inflation factor of 1.27 has, therefore, been used.

Cost estimates have been made without benefit of detailed design drawings. Consequently, in many cases, costs have been arrived at by sizing individual major items of equipment and applying an installation factor found by experience to be suitable for covering all other costs such as foundations, setting of equipment, piping and valving, controls, instrumentation, insulation, electrical, painting, engineering, overhead, and profit. In some cases, preliminary material takeoffs were made and cost estimates made in the usual way. No special item of contingency has been included.

1. Overall costs

Estimated capital and unit costs of plant and of power are summarized in Table V, for the two fields specifically investigated and for the isobutane and steam cycles. A tabulation of the principal capital, annual, and unit costs of power and plant for the range of 10 to 80 mwe are shown in Table VI for the isobutane cycle, and in Table VII for the range of 10 to 50 mwe for the single-stage steam cycle and 10 to 80 mwe for the two-stage steam cycle.

Total estimated capital costs for plants in the range of 10 to 80 mwe for the isobutane cycle and for 10 to 50 mwe and 10 to 80 mwe for the steam cycles are shown graphically in Figure 16. Unit estimated capital costs for the same range of plants are shown in Figure 17.

Table V

ESTIMATED CAPITAL & UNIT COSTS - 1980 BASIS

Item		Hildalgo County Isobutane	Hildalgo County Steam - 1 Stage	Hildalgo County Steam - 2 Stage	Jones No. 2 Isobutane	Jones No. 2 Steam - 1 Stage	Jones No. 2 Steam - 2 Stage
Wells	$	10,100,000	10,100,000	10,100,000	25,000,000	24,400,000	24,400,000
Collection & disposal piping	$	240,000	240,000	240,000	470,000	470,000	470,000
Methane extraction	$	27,000	27,000	27,000	49,000	49,000	49,000
Dehydration	$	60,000	60,000	60,000	112,000	112,000	112,000
Cooling and separation	$	881,000	881,000	881,000	1,856,000	1,856,000	1,856,000
Methane pipeline & compressor	$	4,979,000	4,979,000	4,979,000	6,157,000	6,157,000	6,157,000
Flash chamber & separator	$	--	46,000	129,000	--	102,000	286,000
Heat exchange boiler & separator	$	3,797,000	--	--	10,310,000	--	--
Settling pond	$	31,000	--	--	83,000	--	--
Turbine-generator	$	4,498,000	4,026,000	6,844,000	12,134,000	10,968,000	18,646,000
Condenser	$	3,576,000	1,894,000	2,312,000	9,710,000	5,143,000	6,274,000
Cooling tower	$	804,000	611,000	745,000	2,183,000	1,659,000	2,024,000
Step-up transformer	$	202,000	115,000	195,000	549,000	313,000	532,000
General site development	$	357,000	357,000	357,000	400,000	400,000	400,000
Land	$	--	--	--	--	--	--
Total estimated capital cost(1974)	$	29,552,000	23,336,000	26,869,000	69,013,000	51,629,000	61,206,000
TEC(1980) at 5%/yr inflation(1.27)	$	37,531,000	29,637,000	34,124,000	87,646,000	65,569,000	77,732,000
Kw capacity	Kw	25,280	14,410	24,500	68,660	39,110	66,500
Unit capital cost	$/Kw	1,485	2,057	1,393	1,276	1,676	1,169
Annual cost of ROI, depr., mtce, oper.	$	13,886,000	10,966,000	12,626,000	32,429,000	24,260,000	28,761,000
Annual royalty for energy	$	122,000	122,000	122,000	330,000	330,000	330,000
Total annual cost (1980)	$	14,008,000	11,088,000	12,748,000	32,759,000	24,590,000	29,091,000
Annual credit for methane	$	5,600,000	5,600,000	5,600,000	15,200,000	15,200,000	15,200,000
Annual credit for condensate	$	--	62,000	78,000	--	168,000	212,000
Net annual cost (1980)	$	8,408,000	5,426,000	7,070,000	17,559,000	9,222,000	13,679,000
Kwh/yr at 90% load capacity	Kwh/yr	1.938×10^8	1.105×10^8	1.879×10^8	5.265×10^8	2.999×10^8	5.099×10^8
Unit power cost (1980)	Mills/Kwh	43.4	49.1	37.6	33.3	30.7	26.8

Table VI

TABULATION SUMMARY OF ECONOMICS FOR SECONDARY ISOBUTANE CYCLE

Net power, Mwe	Geothermal water flow bbl/day	Geothermal water flow gpm	Total est. capital cost (1980) $	Total annual cost (1980) $	Annual methane credit, $	Net annual cost, $	Annual power production, 90% load cap. Kwh/yr	Unit power cost mills/Kwh	Unit capital cost $/Kw
10	103,900	3,030	17,062,000	6,361,000	2,215,000	4,145,000	7.67×10^7	54.0	1,706
20	207,800	6,060	30,754,000	11,476,000	4,430,000	7,046,000	1.53×10^8	46.1	1,538
30	311,700	9,090	43,409,000	16,206,000	6,646,000	9,560,000	2.30×10^8	41.6	1,447
40	415,600	12,120	55,435,000	20,704,000	8,861,000	11,843,000	3.07×10^8	38.6	1,386
50	519,400	15,150	67,012,000	25,035,000	11,076,000	13,959,000	3.83×10^8	36.4	1,340
60	632,300	18,180	78,156,000	29,208,000	13,291,000	15,917,000	4.60×10^8	34.6	1,303
70	727,200	21,210	89,098,000	33,304,000	15,506,000	17,798,000	5.36×10^8	33.2	1,273
80	831,100	24,240	99,807,000	37,315,000	17,722,000	19,593,000	6.12×10^8	32.0	1,248

Table VII

TABULATION SUMMARY OF ECONOMICS FOR STEAM CYCLE

Net power, Mwe	Geothermal water flow bbl/day	Geothermal water flow gpm	Total est. capital cost (1980) $	Total annual cost (1980) $	Annual methane & cond. credit, $	Net annual cost $	Annual power production, 90% load cap. Kwh/yr	Unit power cost mills/Kwh	Unit capital cost $/Kw
Steam - 1 Stage									
10	182,400	5,320	22,166,000	8,286,000	3,929,000	4,357,000	7.67 x 10^7	56.8	2,217
20	364,600	10,630	38,461,000	14,400,000	7,858,000	6,542,000	1.53 x 10^8	42.8	1,923
30	546,800	15,950	53,089,000	19,897,000	11,788,000	8,109,000	2.30 x 10^8	35.2	1,770
40	728,900	21,260	66,752,000	25,037,000	15,716,000	9,321,000	3.07 x 10^8	30.4	1,669
50	911,300	26,580	79,709,000	29,915,000	19,646,000	10,269,000	3.83 x 10^8	26.8	1,594
Steam - 2 Stage									
10	107,310	3,130	16,293,000	6,078,000	2,318,000	3,760,000	7.67 x 10^7	49.4	1,629
20	214,290	6,250	28,863,000	10,779,000	4,635,000	6,144,000	1.53 x 10^8	40.6	1,443
30	321,600	9,380	40,329,000	15,071,000	6,952,000	8,119,000	2.30 x 10^8	35.7	1,344
40	428,910	12,510	51,132,000	19,118,000	9,270,000	9,848,000	3.07 x 10^8	32.5	1,278
50	535,890	15,630	61,468,000	22,992,000	11,588,000	11,404,000	3.83 x 10^8	30.2	1,229
60	643,200	18,760	71,445,000	26,734,000	13,905,000	12,829,000	4.60 x 10^8	28.3	1,191
70	750,510	21,890	81,134,000	30,369,000	16,222,000	14,147,000	5.36 x 10^8	26.8	1,159
80	857,480	25,010	90,583,000	33,914,000	18,540,000	15,374,000	6.13 x 10^8	25.5	1,132

Figure 16

TOTAL ESTIMATED CAPITAL COST - 1980 COST BASIS

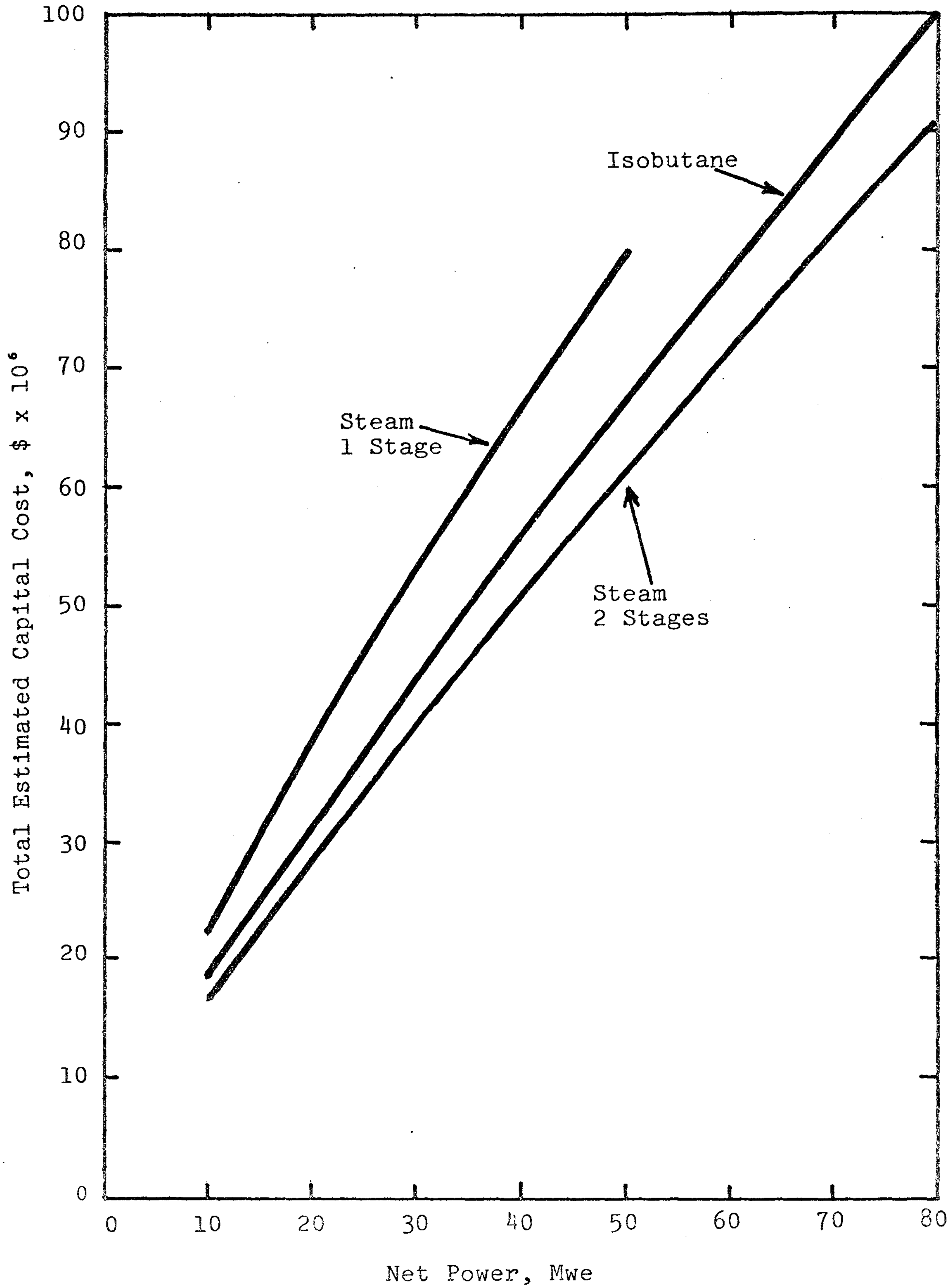
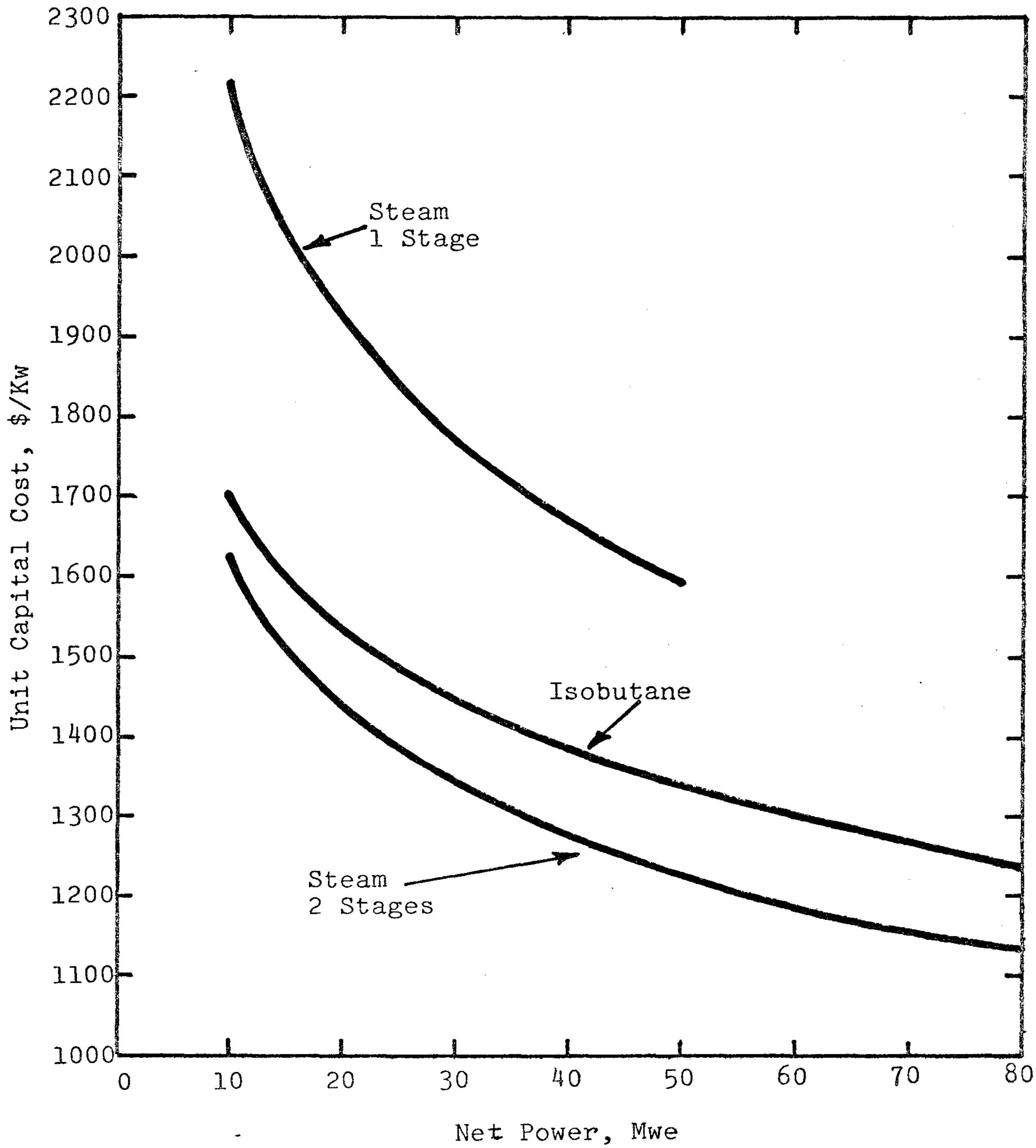


Figure 17

UNIT CAPITAL COSTS
1980 COST BASIS



Unit electric power costs for the isobutane and steam cycles, both with and without credit for methane production, are shown in Figure 18. The estimated cost of purchased power in 1980 has also been included for comparison purposes. While the estimated unit cost of geothermal power is shown higher than for purchased power, it could be less, if one or more of the three following points can be realized:

- Geothermal water driving pressure required is substantially less than calculated for this study, thus permitting the harnessing of some of the kinetic energy for power generation. This is much less costly per unit of power produced than for the production of power from thermal energy.

- Cost of heat exchangers and condensers can be substantially reduced. At present, the cost of these items can be reduced by half if purchased from Japan or West Germany.

- A better secondary cycle fluid can be found which will give better cycle efficiency and heat transfer coefficients, thus reducing the heat transfer surface area required for the heat exchangers and condensers.

2. General site development and land

No costs have been included for land. It has been assumed that land would be state-owned.

Preliminary general plant layouts were made for each of the two sites--Hidalgo County and Jones No. 2. From these layouts, takeoffs were made of fencing and roads required. Approximate costs were developed for site grading and drainage, potable water, sanitary disposal, electric power service, and for 6,000 square feet of shop, office, control room, and warehouse space. A miscellaneous item was included for the many small costs common to all site development programs.

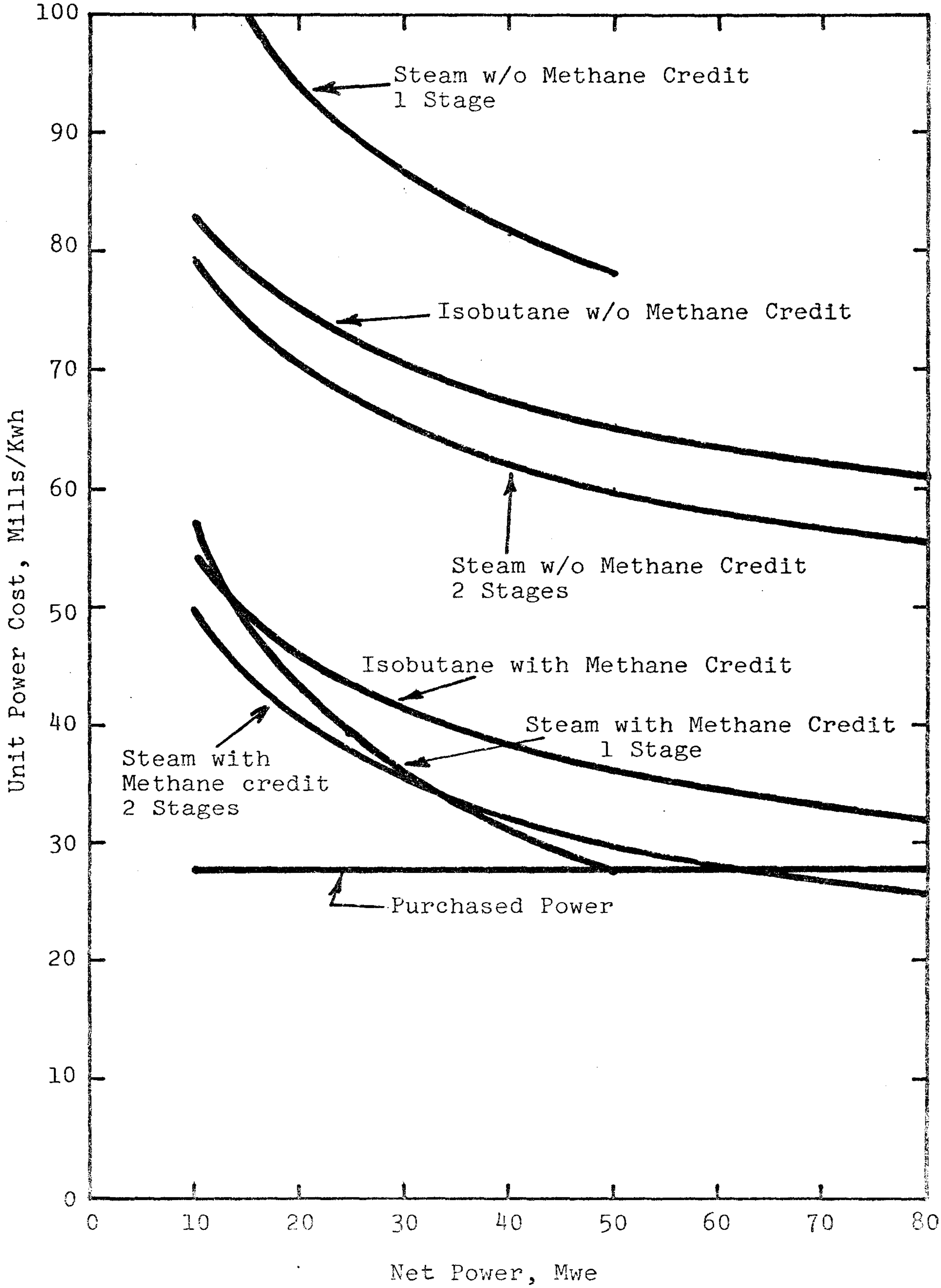
3. Well costs

Estimated costs for wells are based on costs presently existing. Costs are increasing so rapidly it is difficult to establish other than a momentary base. Both drill rigs and casing are in extremely tight supply. Should this situation ease up in the next few years, costs could conceivably level off.

It has been assumed that one out of each three wells will be dry. Dry wells could be suitably plugged and

Figure 18

UNIT POWER COSTS - 1980 COST BASIS



cased for flow to the assumed disposal formation at 6,000 feet. Thus, some cost can be salvaged. Each producing source well to the 15,000-foot depth has been estimated at $1,100,000 each. Each reinjection well drilled only to 6,000 feet has been estimated at $270,000. Each dry well converted to a reinjection well has been estimated at $900,000. One spare production well and one spare reinjection well has been included for each case.

4. Collection system costs

Production and reinjection wells have been laid out on a grid of 300-foot spacing between wells. Steel piping, insulated, has been sized and the total lengths of each size determined. Costs have been estimated based on cost of materials, labor, overhead, construction equipment, engineering, and profit.

5. Methane extraction and processing

The methane extraction unit was sized for the assumed conditions using an existing computer program based on generally accepted chemical engineering principles. The equipment cost was estimated and an installation factor of 4.0 was applied.

The methane compressor, cooling, separation, heat recovery, and dehydration equipment, and the pipeline were sized and estimated on the basis of similar current material and plant costs. A 50-mile pipeline was assumed as representing a typical distance the methane would be transported to a customer.

6. Power production costs

The flash chamber and separator for the steam cycle was sized for the assumed conditions using an existing computer program based on generally accepted engineering principles. The equipment cost was estimated and an installation factor of 4.0 was applied.

The heat exchange boilers and superheaters were sized for the assumed conditions by standard engineering calculations. One written and three verbal quotations were obtained and averaged. This came to $8 per square foot of heat transfer surface. An installation factor of 2.3 was applied, a reasonable factor considering the very great surface area involved.

Unit costs for the isobutane turbine were taken at $50 per Kw, and for the electric generator at $20 per Kw.

An installation factor of 2.0 was used. Unit costs were based on best available costs as supplied by manufacturers of comparable equipment.

Condensers were sized and the costs estimated as for the heat exchangers.

Cooling tower costs were based on 1967 published costs increased by a factor supplied by a major manufacturer of cooling towers.

7. Natural gas credit

The rapidly increasing cost of natural gas makes a prediction of its cost in 1980 highly uncertain. An estimated value in 1980 of $2 per thousand cubic feet has been used. This is based on a general averaging of estimates obtained from a number of sources. The natural gas, or methane, extracted from geothermal water should be readily marketable.

8. Condensate credit

The steam cycle will produce a substantial quantity of condensate. Being pure water, it should have a market at least as potable water. A value of 10 cents per thousand gallons has been assigned to condensate produced. Condensate production in the Hidalgo County case should be 1,200 gpm, and in the Jones No. 2 case 3,300 gpm. No cost has been included for transporting this condensate to a user.

9. Royalty for energy

Royalty payments for lignite in some parts of the country run at about 20 cents per ton. Assuming the heat of combustion of lignite to be 7,500 Btu per pound, the royalty payment amounts to 1.33 cents per million Btu. Since lignite is produced in Texas, it seems logical that royalty for energy in the geothermal water would approximate that for lignite. The royalty to be paid for energy, therefore, was based upon 1.33 cents per million Btu. Available energy was considered to be that energy in the geothermal water between the wellhead temperature of 385°F and the condensing temperature of the power fluid of 110°F.

10. Depreciation allowance

Depreciation allowance is applied to oil and gas as well as brines. However, the rate varies. It is not known what the depreciation allowance might eventually be for geothermal waters, or even if there will be one. Because of the uncertainty and the unknowns, and since any depreciation allowance which might ultimately be established would be well within the factor of error of other costs in this study, it was decided not to include it herein.

11. Maintenance and operation

An analysis of the 1971 Federal Power Commission report, "Steam-Electric Plant Construction Cost and Annual Production Expenses", showed that the higher range of maintenance and production annual costs for all utility steam-electric plants in the country came to about 8 percent of total estimated capital. It is felt that this is a reasonable figure to apply to geothermal power plants.

12. Business costs

While there are different methods of arriving at business costs, the one used in this study has been found by experience to be sound and workable for major industry. These costs can be itemized as follows, with the percentages listed applying to total estimated cost:

- Depreciation at 5 percent
- Taxes and insurance at 1.1 percent
- Overhead at 1.3 percent
- General and administrative at 1.6 percent
- Return on investment at 20 percent

This totals 29 percent. The 20 percent for return on investment includes cost of money, interest on construction funds during construction, and profit. While the amount of return on investment may vary with type of project, 20 percent has been considered reasonable for a power plant of this type.

H. Environmental Considerations

Geothermal energy is considered to be one of the least polluting of the several forms of energy known to man.[21] Geopressured geothermal sources are believed the least polluting of any presently available form of geothermal energy. However, it is required by law that environmental impact statements required under the National Environmental Policy Act must be prepared prior to the development of the resource. Complete environmental statements must include the impact upon the actual site and, thus, must await site selection. Some general considerations will be common to all sites. These include subsurface effects such as subsidence and seismic effects and surface effects such as possible impact of salty waters on agriculatural lands, the general ecology, lakes and rivers; possible pollution of the atmosphere; changes in the landscape; and noise pollution from the wells.

Of primary concern in the Gulf Coast is the possibility of subsidence due to the withdrawal of large quantities of water. The subsidence in the Baytown area near Houston is ample evidence of the danger. In this case, water is being withdrawn from shallow depth at rates exceeding natural replenishment. Geopressured reservoirs will not be replenished at all. However, these reservoirs are very deep and sealed from above by a caprock. This greatly decreases the possibility. One authority[22] states, "although subsidence will most surely occur in tectonically active regions, no subsidence should occur from production in the geopressure zones." He bases this statement on the excessive pressures present and upon the observation that oil and gas production from these zones have not produced detectable subsidence. A second authority[15] believes that subsidence is unlikely due to the depth and the arch effect expected from the overlying caprock. All agree that the question of subsidence cannot be clearly answered until actual production occurs.

Seismic effects are serious geothermal considerations in regions of high tectonic activity such as the Imperial Valley of California. Changes in fluid pore pressure in the formation has been established as the source of the triggering of earth movement in the earthquakes in the Denver region. This case was due to injection of waste fluids. The effect is pronounced in massive rocks of low porosity and permeability. It is unlikely that this will be a major concern in the Gulf Basin where the formations are more porous and permeable and faults are not tectonic in nature.

Surface environmental effect should be minimal. It is expected that the waters will be completely contained and the waste brine will be injected into medium depth sands below the fresh water levels but above the geopressured zone. Should blowouts occur, salt water could be released with detrimental effects on neighboring farmland, rivers and lakes, and the area in general. Two such blowouts have occurred at the Cerro Prieto site in Mexico.(23) One well ran wild for 30 days flowing 30,000 ppm total dissolved solids brine. Approximately 4 square kilometers (10 square miles) of farmland were affected. The possibility of blowout cannot be eliminated but, as mentioned previously, technology for drilling into the geopressured zone is well advanced and blowouts are now rare.

Air pollution is a serious consideration in many convective steam and water systems such as The Geysers in California. These reservoirs generally contain dissolved hydrogen sulfide and traces escape into the air. The geopressured water does not in general appear to contain this gas. However, it could be present and would then have to be dealt with. Other air pollution is expected to consist primarily of carbon dioxide which will separate with the methane and may be discharged to the air. This will be of no serious consequence.

Conventional geothermal sites experience considerable noise pollution particularly when wells must be vented. This practice should not be necessary in geopressure but some noise may occur in the pressure drop and flashing operations.

Mufflers are used where discharge occurs to alleviate the problem. Any noise in normal operation should be minimal and of no concern.(23)

Environmental aesthetics should be considered in design of the plant. Compatibility with the existing landscape should be only a matter of good design. Piping from the wells to the plant will be the primary problem since the plant itself will have a low profile, in fact, much lower than existing nuclear or fossil fueled power plants.

I. Legal Considerations

Geothermal waters presents a unique problem of legal definition. Is the water a mineral, a gas, or just water and, if water, should surface water rights apply? Gulf Coast geopressured waters compound the problem by containing dissolved hydrocarbons andby existing in definable reservoirs many square miles in area. The question of ownership, royalties, rule of capture and leasing rights must be settled before extensive development can occur.

The definition problem is the most pressing question. Other concerns such as state regulatory agencies involved, power distribution networks, public lands, etc., are involved. Legislative action at the state level must be taken in some cases and ultimately court rulings may be required.

Legal problems in the utilization and development of geopressured waters may also involve patent litigation. At least two patents[24, 25] owned by the Shell Oil Company have geen granted. These patents claim the method of obtaining the water from the reservoir, converting the heat to electrical energy, production of fresh water from the brine, reinjection of waste fluid and utilization of gepressured water for fluid-mining procedures in oil recovery operation. These patents apply specifically to geopressured geothermal waters and may be applicable to the proposed processes.

J. Programs in Progress

Limited investigative work is being carried out by federal agencies to investigate this resource. A deep thermal mapping program for the Gulf Coast has been in progress for several years. This project is being conducted by a USGS team headed by Dr. Paul Jones of Bay St. Louis, Mississippi. They are preparing maps of isothermal geosurfaces of which Figures 3 and 4 are examples. Dr. Jones is probably the foremost authority on the Gulf Coast thermal regime. His work is continuing and it is reported that the USGS is expanding its effort to include detailed mapping of the top of the geopressured zone, constructing geological cross-sections of the basin and mapping sand facies.

A program is also underway at the Lawrence Livermore Laboratory of the University of California to investigate geopressured geothermal energy. This work is supported by the Atomic Energy Commission and consists of the development of a total flow energy conversion system[26], survey work, and a geological study subcontracted to the Texas Bureau of Economic Geology.

The "lead" government agency in geothermal is the National Science Foundation (NSF). NSF through the RANN program is preparing to support investigation of geopressure. Present plans are reported to include geological studies and other general survey efforts. NSF is presently negotiating with the University of Texas and with Louisiana State University and have issued a request for proposals from any qualified organization. They have reported the receipt of several proposals to date.

Private investigation appears to have been limited in nature but oil companies and other interested corporations may have considerable proprietary information. The Dow Chemical Company, as evidenced by this report, has been conducting investigative work. The basis for this effort has been Dow's search for economical sources of electric power to meet the high power need of Dow installations in Texas and Louisiana.

Efforts to develop this known resource appear at present to be limited to investigation only in spite of the vast store of information available in the form of thousands of logs from wells drilled in the area in search of oil and gas. This is undoubtedly due to past economy of power produced from natural gas, the high capital cost of geopressured geothermal energy and high risk involved. Although the resource is known, two very important questions remain unanswered: (1) the size of the water reservoirs and, therefore, their productivity and (2) the natural gas content which is the controlling factor in the economics of power production. These two unknowns plus the difficulty of obtaining a proprietary position to assure return on investment make the development a "high risk" capital venture. However, these same factors plus the potential impact upon the public interest, would appear to adequately justify the expenditure of public funds to promote the development of the resource.

K. Proposed Developmental Programs

Geopressured geothermal resource development will require the expenditure of large amounts of high risk capital. However, the possible interest to the public justifies the expenditure of governmental money on such a project. A development should be undertaken. This program should be divided into phases such that cost-benefit analysis can be performed periodically, as data is gathered, to evaluate the desirability of continuing to invest in the project. Such a program is presented here.

The overall objective of the project is to demonstrate the feasibility of the production of electric power, natural gas, and fresh water from the geopressured waters of the Gulf Coast. The program presented here is a six-phase approach to this objective, culminating the construction and operation of a total demonstration plant. Definition of these six phases and proposed timing is shown in Figure 19.

The program must provide answers to certain unknowns vital to the ultimate success of geopressured water utilization. Most pertinent of these unknowns are believed to be:

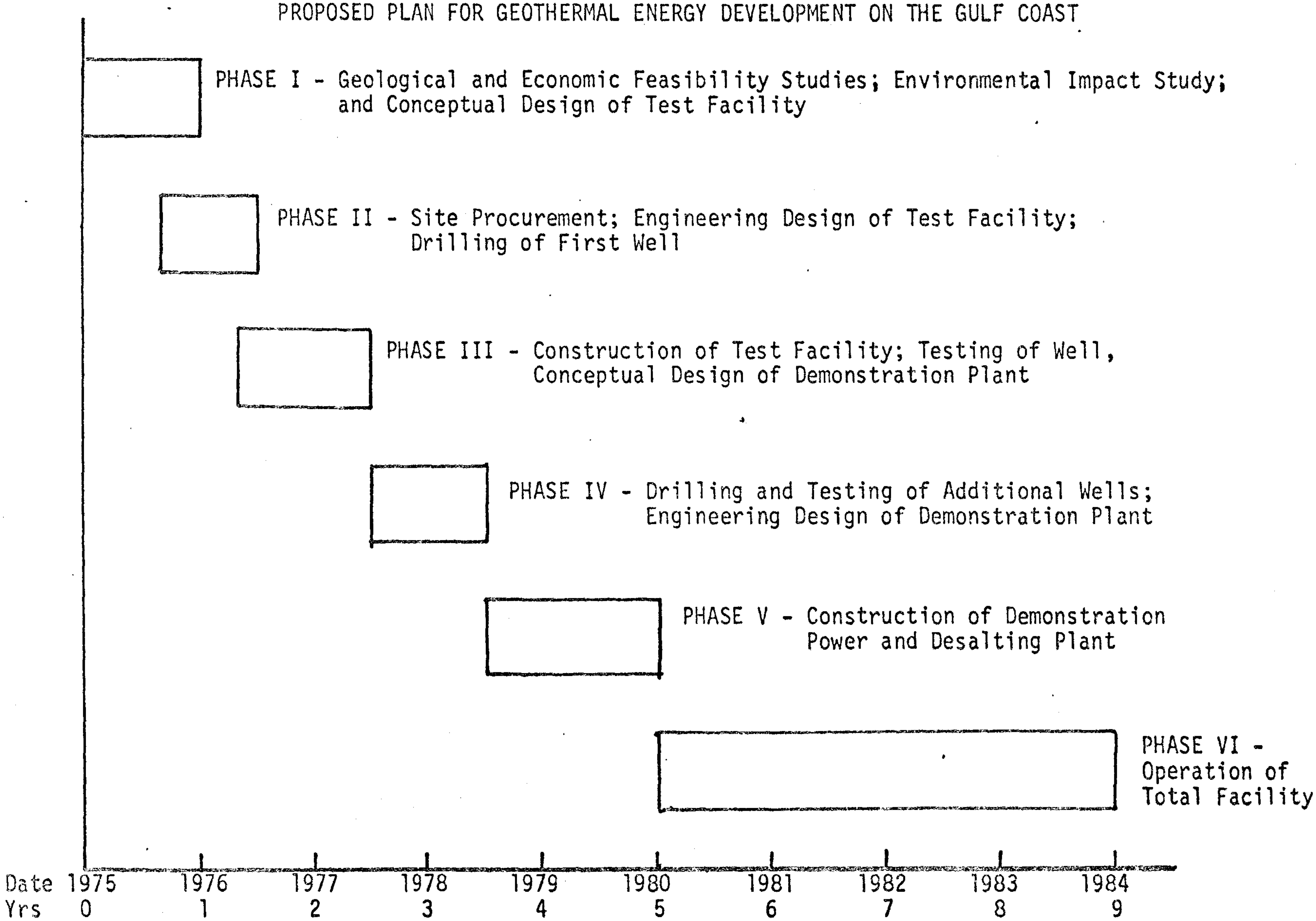
Reservoir size
Well production rate
Well completion techniques
Natural gas quantity and recovery
Scale control
Materials of construction
Subsidence and other environmental effects

Many of the above answers can only be determined by drilling actual wells. However, prior to that operation, certain preliminary studies must be made. These are feasibility studies and are included in Phase I of the program. Detailed objectives of the other five phases would be dependent upon results of Phase I.

Phase I, Feasibility Studies, is a one-year program to furnish a data base on which to site and drill on exploratory well. The preimary objective of Phase I is the siting of the well through geological and environmental studies. Other objectives include establishment of economic feasibility, determination of environmental impact, and design of the well and test facilities. Phase I will establish the technical, practical, and economic feasibility of the total program and develop all necessary information to justify the expenditure of the estimated one million dollars required to drill a test well. In addition Phase I will perform the development work required to bring the project to the point of readiness to take bids for the actual well drilling. Finally, Phase I will furnish an information base for the recommendation of areas of needed

Figure 19

PROPOSED PLAN FOR GEOTHERMAL ENERGY DEVELOPMENT ON THE GULF COAST



process development. A listing of the proposed objectives of Phase I is shown in Table VIII.

Timing for the total program is nine years. However, the rate of progress in an aggressive approach would be determined by the degree of risk acceptable in moving the phase time forward.

Preliminary estimates of the cost of such a program are $500,000 for the Phase I effort and $35,000,000 for the total program. A breakdown of the estimated cost per year is shown in Table IX.

At the close of the sixth year, feasibility could sufficiently be demonstrated to encourage private capital to undertake construction of a nominal 50-megawatt plant. Assuming a five year construction period for this plant an average expenditure of 15 million dollars per year would be required. This would put 50 megawatts on line by the eleventh year of the program. Additional plants could probably be built cheaper at say $1,200/kw capital cost. Construction of a total of 20,000 megawatts of capacity over the next twenty years would then require an average expenditure of 1.2 billion dollars per year.

Manpower requirements can be calculated very roughly on the basis of 40% of the capital investment being required for construction manpower. For a total expenditure of 2.4×10^{10} dollar and $26,000 per man-year average cost, a total of 3.46×10^{5} man-years would be required. Or, over a twenty year period, an average of 17,000 persons would be employed in the construction of the 400 plants.

Operating manpower is estimated at 50 mw per plant. On this basis, 20,000 persons would be employed in some way once all 400 plants were in operation.

The development phase, or the first six years, would require negligible manpower compared to the later twenty five years.

This resource seems to require numerous small power plants, although large reservoirs or additional waters from the shales could drastically change this picture, lower costs, and vastly increase the potential. However, the possibility of numerous small plants is very likely. This by nature introduces a secondary problem, that of distribution of the power. The apparent solution would be at the least a coastal power gird or, even better, a state-wide mandatory power grid to distribute the 20,000 megawatts to the consumers. Such a grid may well be desirable in any case.

Table VIII

OBJECTIVES OF PHASE I

- Establish a geological base for site selection, water properties, reservoir estimation, and subsidence.
- Prepare an environmental impact statement.
- Determine resource requirements for economic usefulness.
- Develop specifications for a test well.
- Prepare a conceptual design for a test well and facility.
- Recommend areas of needed process development.

Table IX

DEVELOPMENT COST ESTIMATE

Year of Program	Phases Included	Cost Dollars, $\overline{M}$
1	I & II	1.5
2	II & III	3.0
3	III & IV	5.0
4	IV & V	8.5
5	V	7.0
6	VI	2.5
7	VI	2.5
8	VI	2.5
9	VI	2.5
	Total Cost	35 $\overline{M}$

L. Conclusions and Recommendations

It should be recognized that the potential of geopressured geothermal resources is controversial. This report is based on the best available information and generally has presented what the authors believe is a conservative approach to the economics of the processes involved. However, the resource itself has been assumed to be of sufficient magnitude to constitute a viable power source. Proof of this concept must await actual development attempts.

Capacities and economics of two potential reservoirs in the South Texas coastal region have been calculated. Table X shows a summary of these results. Both reservoirs can produce sufficient water to support a small power plant. The power produced could be economical in the 1980's.

Firm estimates of the total potential in Texas must await the geological studies now underway. However, preliminary surveys[2,5] of geopressured geothermal potential in Texas indicate a realistic possibility of 400 onshore reservoirs each capable of producing an average of 50 megawatts of power for a 20 year period. Thus, a total of 20,000 megawatts potential exists onshore with perhaps an equal amount offshore. This total does not include natural gas production.

The potential BTU production from these 400 sites, calculated on the basis of the isobutane cycle when 3.8×10^6 bbls of 375°F water cooled to 186°F in the cycle is required to produce one megawatt year of power, is 5.44×10^{15} BTU per year. If we assume 30 s.c.f. of natural gas yield per barrel of water, an additional 2.28×10^{15} BTU per year of potential energy would be available from the 400 sites in the form of natural gas. Using a standard 1,000 BTU per kilowatt hour for a gas fired power plant, this would given an additional 26,000 megawatts per year of power if the gas was used to produce power.

On this basis the following conclusions are believed to be valid.

1. Geopressured geothermal power plants could be developed along the Gulf Coast of Texas to supply economical power to the area on the basis of producted 1980 costs.

2. These power plant could be small, mostly 30 to 70 megawatts, but could be numerous. A total of 20,000 megawatts is a conservative estimate in the next 30 years.

3. This water would also produce at least 6 million cubic feet of natural gas per day. The gas could

Table X

GEOTHERMAL POWER FACILITY - SUMMARY TABLE

Reservoir Location and Power Cycle	Water Yield bbls/day	Number of Wells	Natural Gas Yield s.c.f./day x 10^6	Net Power Megawatts	Capital Cost $/Kw (1980)	Unit Power Cost Mills/Kw(1980)
Hidaldo County	262,600	6	7.8			
Isobutane				25.28	1485	43.4
Steam - 1 stage				14.41	2057	49.1
Steam - 2 stage				24.50	1393	37.6
Jones No. 2 - South Texas Coast	713,100	15	21.4			
Isobutane				68.66	1276	33.3
Steam - 1 stage				39.11	1676	30.7
Steam - 2 stage				66.50	1169	26.8

Conditions for Calculations:

Well depth - 15,000 feet
Water temperature - 385°F
Methane content - 30 s.c.f./bbl
Methane value - $2.00/1000 s.c.f.
Return on investment - 20%

be collected for sale or could be piped to large central power plants to produce an additional 26,000 megawatts of power.

4. Cost of the geothermal power would range from 25 to 35 mills per kilowattt.

5. The technology to develop this potential exists today. However, additional research and development could lower the cost of the power produced.

6. High capital investment and a high risk factor is involved in the development of this resource. This, plus the unlikelyhood of a proprietary position, make the private development unlikely.

7. Development of this resource appears to be in the public interest both to the nation and to the State of Texas. Therefore, it appears to be a suitable area for the investment of public funds.

8. Various federal agencies have begun investigative efforts but no comprehensive development programs are underway at present.

It is recommended that a program be undertaken by combined academic-industrial effort to develop the resource. This program should be supported primarily by state and federal funds. The initial objectives of the program should be to locate a reservoir site, drill wells and produce the water to obtain precise analyses for natural gas content and obtain the data to calculate reservoir size and productivity. If the results are satisfactory, a small demonstration power plant should be constructed and operated. The entire project should be designed in such a manner that a successful end result will encourage private development of additional reservoirs to the extent of the resource. It is estimated that the cost of such a demonstration program would be of the order of 35 million dollars.

It is also recommended that investigative research and development on improved methods of producing power from geothermal resources be continued and expanded and that geopressured resources be included as a integral part of that program.

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