CHAPTER 3

RESERVOIR DEVELOPMENT AND MANAGEMENT

Work Group

Jay F. Kunze (Chairman), Richard G. Bowen, Ken Foit, Dennis Goldman, Elliot Zais

CONTENTS

(Chapter 3, Drilling regulations, continued)

FIGURES

(Chapter 3, Figures, continued)

TABLES

INTRODUCTION

Reservoir development and management are well developed sciences in the petroleum, natural gas, and even groundwater irrigation industries. The principal experiences in the geothermal industry are at several fields (in four different countries) where electricity is being generated in minimum sized blocks of 75 MWe or nominally 350 MWt. These several fields are generally vapor dominated, two of them completely so: Lardarello and The Geysers. The liquid-dominated fields at Waiakei, New Zealand and Cerro Prieto, Mexico generate flash steam at the well heads. The techniques, considerations, and plans for direct-heat application reservoir development will differ substantially from the above examples. The projects generally will be in the 1 MWt to 50 MWt (3.4-170 million Btu/hr) range, an order of magnitude less than the minimum-sized modules for electric projects. Instead of 10 to 100 wells typically planned for a field, direct applications may require only one or two wells. Whereas the electric developments can call the first few production wells exploratory and hope to reduce costs significantly on future wells, the first few direct-application wells may be the only ones needed, and perhaps, the only ones ever to be drilled in the field.

Reservoirs in the large fields mentioned above can be evaluated with interference measurements between wells. A direct-heat application may only have one well, so interference testing is impossible without the expense (usually prohibitive) of drilling observation wells. Single-well tests, therefore, are extremely important, and may be the only means of technically evaluating the long-term performance of the reservoir for direct-heat applications.

Finally, the relative costs of electric vs. direct-applications projects must be recognized in planning the cost of the reservoir development and management program. A project that costs 1/10 as much as an electric project cannot afford (in fact does not need) the same sophistication in a reservoir management program as one for a planned 200 MW electric project. Cost savings can be significant for a direct-applications project. Consequently, the direct-application geothermal industry may develop a cadre of technicians oriented specifically to the needs of this industry--those who drill inexpensively and make the most out of evaluating sparse data.

PRODUCTION-WELL DRILLING

Drilling the wells probably represents the greatest expense and the greatest risk in geothermal-energy utilization. Once a geothermal-reservoir prospect is fairly certain, the next step is to confirm the size and usefulness of that resource, and confirm the economics of getting the energy out of the ground and using it for a period of time sufficient to amortize the investment that will need to be made.

Let us assume that we know where the first production or exploration-production well is to be drilled. We also have a depth estimate of the resource (with a contingency of 25 to 50% added to this depth estimate), and we also have geochemical or other data to indicate the temperatures to expect. We need to estimate the quantity of fluid we expect to produce from a single well. Recall that most direct-heat applications will bring the fluid to the surface in the liquid phase. Large flow rates--like 1000 or more gpm (gallons per minute; 63 l/s; 34,000 barrels a day)--are most desired. But what is the likelihood of this from a single well?

Typical well flow rates

1. Irrigation wells delivering 4000 gpm (250 l/s) are not uncommon, but 1000-2000 gpm (60-125 l/s) are more typical. Such flows conceivably could be expected from wells in shallow, low-temperature geothermal aquifers, using pumps.

2. Free-flowing (artesian) geothermal wells that produce 500 gpm (30 l/s) for sustained

periods are rare; however, 50-100 gpm free-flow rates are not uncommon.

3. Deep geothermal wells (greater than 3200 ft, 1000 m) that can be pumped to produce a sustained 1000 gpm (60 l/s) do exist, particularly in highly fractured, volcanic formations (Iceland, for instance), but these are exceptional. Flow rates in the range of 500 gpm (30 l/s) would be considered a good geothermal deep well.

Comparison of oil and geothermal costs and the relative risks

The geothermal well, if 60°F (33°C) of temperature difference can be stripped from the water and the flow rate is 1000 gpm (60 l/s), will produce $1400 worth of heat each day, if heat is valued at $2/million Btu ($2/million kJ). But if the application is space heating, the well may only be used 25% to 50% of its full capacity yearly. On the other hand, a good oil well producing 500 barrels a day (1 l/s) will earn $3000 to $15,000 per day, every day (depending on whether it is sold at "old" or "new" oil prices). The oil well might only cost $350,000, giving a very attractive return on investment even after expenses. The geothermal well cost must be close to this number, particularly since each producing well must, in general, be accompanied by one-half to one full disposal well. For instance, if the cost of the producing well, the pump, pipeline, and disposal facility for that well totals $600,000, the return on investment would be about 25%, less any operating expenses. Qualitatively, the attractiveness of return on investment appears much better for an oil well than for a geothermal well. However, the ratio of success to attempts should be much higher with geothermal, thus the exploratory costs chargeable to the total operation should be less for geothermal. For example, oil-wildcat success ratio is less than 1 in 15. More deliberate exploration in previously proven areas succeeds about 1 in 4. Geothermal exploration needs to be significantly better if it is to compete economically. Since geothermal profit margins will generally be much less than for gas and oil, geothermal drilling and development cost must be kept as low as possible.

Because one of the keys to successful geothermal development is to drill wells less expensively than oil and gas wells, it is appropriate to emulate the water-well driller to whom well cost is very critical, rather than the oil and gas driller. Cost to the latter is secondary because he must drill as many holes as possible with a given rig to get as many producing wells as possible in a given time. Unlike the oil producer who is mobile, able to go where the oil can be found, the geothermal developer must have a user for the heat available at the location of the well.

These distinctions in philosophy and attitude of the drilling companies and drilling consultants are important. Although the equipment and safety precautions for geothermal drilling are more closely related to oil and gas drilling, the techniques needed to tap the resource and keep the cost minimal are more in empathy with water-well drilling.

Well-design considerations

Casing size, particularly at the bottom of the casing string, and the diameter of the hole in the producing section need to be established before the size of the well at the surface can be determined. In general, the production of the well will depend partially on each of the following:

1. Surface area of well bore in the producing zone (i.e., nominally proportional to diameter of well);

2. Pressure drop from bottom of well to the top (i.e., inversely proportional to the diameter to the 3.75 power).

Thus, for deep wells (greater than 2000 ft, 600 m), (2) is a major consideration. For shallower wells, (1) is the major consideration. However, in the case of poor permeability ("tight" wells), or predominate fracture permeability, the production capability is quite insensitive to the diameter of the well bore.

As a guide to pressure drops within various sized casing, the following table gives a few examples:

Casing Size		Pressure Drop in 1000 ft. (300m) for 1000 gallons/min flow (60 liters/second)
6 5/8 (5.75" ID)	16.8 cm (14.6 cm ID)	35 psi (240 kPa)
9 5/8 (8.91" ID)	24.4 cm (22.6 cm ID)	4.8 psi (33 kPa)
13 3/8 (12.6" ID)	34.0 cm (32.0 cm ID)	0.70 psi (4.8 kPa)

To scale to other flows, the pressure drop is proportional to the flow rate squared. Another factor in calculating well size is the installation of a pump. The inside casing size requirements for various capacity pumps are approximately as follows:

Flow No Greater Than	Requires Casing Diameter of
20 gpm (1.26 l/s)	4" (10.2 cm)
100 gpm (6.30 l/s)	6" (15.2 cm)
500 gpm (31.50 l/s)	9" (22.9 cm)
2000 gpm (126.00 l/s)	12" (30.5 cm)

Pump types are discussed in Chapter 5. For the purposes of this chapter, we need be concerned only with the fluid level in the well. The depth for setting the pumps should be sufficient to allow for long-term drawdown,[1] as determined from the well testing results discussed later in this chapter. Since those data are not available prior to the time the well is tested, other information must be used to estimate the pump-setting depth and hence the casing design for the well. It is not unusual to consider "drawing down" a well (i.e., reducing the water level in the well bore) by as much as 1000 ft (300 m). The pumping costs for lifting water from an additional 1000-ft (300-m) depth generally are much less when totaled over the lifetime of the well than is the cost of an additional well.

Types of drilling equipment

Basically, two types of drilling methods are commonly used:

1. The old-fashioned cable-tool drill (Figure 1). This is not a true drill since it doesn't rotate but employs a heavy hammer bit that pounds and crushes the rock. The rock mixes with a water slurry which is then bailed out of the hole. Often casing is driven directly behind the bit. This method is the least common used for drilling geothermal wells, but it is still common for water-well drilling. It does have advantages for low- to moderate-temperature geothermal wells.

   One advantage of cable-tool drill rigs is that they are comparatively inexpensive to buy or rent, and can be operated by two men. Since they don't circulate water, they can operate in freezing climates and be shut down overnight. (Rotary rigs using water or mud must pre-

[1] Other considerations discussed in Chapter 5 are important. A minimum net positive suction heat (NPSH) must be maintained over the pump. In determining drawdown amounts to maintain NPSH, steam-saturation pressure and pressure of dissolved gases must be considered.

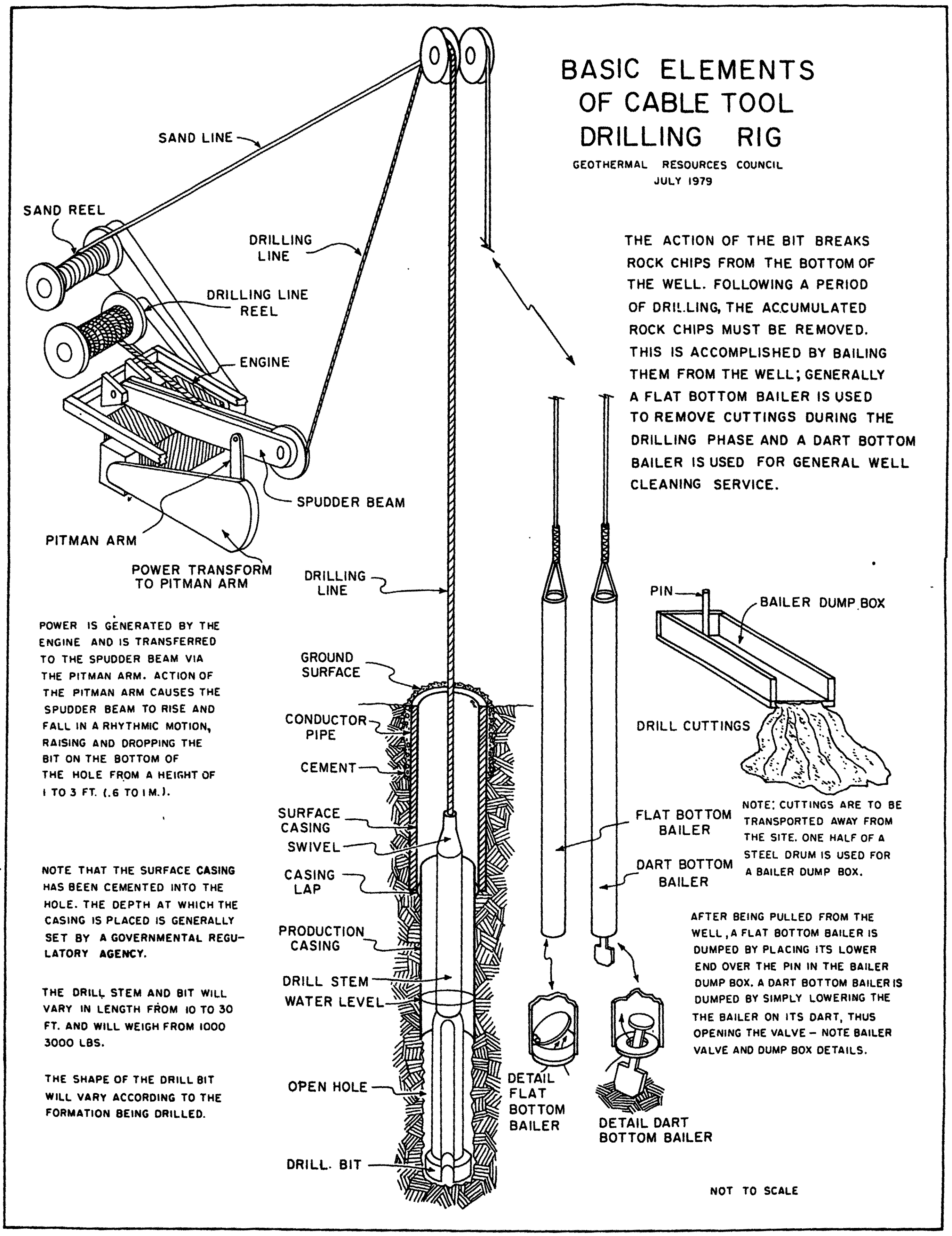

BASIC ELEMENTS
OF CABLE TOOL
DRILLING RIG
GEOTHERMAL RESOURCES COUNCIL
JULY 1979
SAND LINE
SAND REEL
DRILLING LINE
DRILLING LINE REEL
ENGINE
SPUDDER BEAM
PITMAN ARM
POWER TRANSFORM TO PITMAN ARM
DRILLING LINE
POWER IS GENERATED BY THE ENGINE AND IS TRANSFERRED TO THE SPUDDER BEAM VIA THE PITMAN ARM. ACTION OF THE PITMAN ARM CAUSES THE SPUDDER BEAM TO RISE AND FALL IN A RHYTHMIC MOTION, RAISING AND DROPPING THE BIT ON THE BOTTOM OF THE HOLE FROM A HEIGHT OF 1 TO 3 FT. (.6 TO 1 M.).
NOTE THAT THE SURFACE CASING HAS BEEN CEMENTED INTO THE HOLE. THE DEPTH AT WHICH THE CASING IS PLACED IS GENERALLY SET BY A GOVERNMENTAL REGULATORY AGENCY.
THE DRILL STEM AND BIT WILL VARY IN LENGTH FROM 10 TO 30 FT. AND WILL WEIGH FROM 1000 3000 LBS.
THE SHAPE OF THE DRILL BIT WILL VARY ACCORDING TO THE FORMATION BEING DRILLED.
GROUND SURFACE
CONDUCTOR PIPE
CEMENT
SURFACE CASING
SWIVEL
CASING LAP
PRODUCTION CASING
DRILL STEM
WATER LEVEL
OPEN HOLE
DRILL. BIT
THE ACTION OF THE BIT BREAKS ROCK CHIPS FROM THE BOTTOM OF THE WELL. FOLLOWING A PERIOD OF DRILLING, THE ACCUMULATED ROCK CHIPS MUST BE REMOVED. THIS IS ACCOMPLISHED BY BAILING THEM FROM THE WELL; GENERALLY A FLAT BOTTOM BAILER IS USED TO REMOVE CUTTINGS DURING THE DRILLING PHASE AND A DART BOTTOM BAILER IS USED FOR GENERAL WELL CLEANING SERVICE.
PIN
BAILER DUMP BOX
DRILL CUTTINGS
NOTE: CUTTINGS ARE TO BE TRANSPORTED AWAY FROM THE SITE. ONE HALF OF A STEEL DRUM IS USED FOR A BAILER DUMP BOX.
FLAT BOTTOM BAILER
DART BOTTOM BAILER
AFTER BEING PULLED FROM THE WELL, A FLAT BOTTOM BAILER IS DUMPED BY PLACING ITS LOWER END OVER THE PIN IN THE BAILER DUMP BOX. A DART BOTTOM BAILER IS DUMPED BY SIMPLY LOWERING THE THE BAILER ON ITS DART, THUS OPENING THE VALVE – NOTE BAILER VALVE AND DUMP BOX DETAILS.
DETAIL FLAT BOTTOM BAILER
DETAIL DART BOTTOM BAILER
NOT TO SCALE

FIGURE 1

vent freezing of the fluid if they shut down overnight, consequently they usually run around the clock.)

Another advantage is that casing can be driven directly behind the drill and eliminate caving of the hole and lost circulation, serious problems for those rotary drills that cannot drive the casing. However, casing drivers can be mounted on most rotary drilling rigs.

The main disadvantages are that blowout preventers are not readily adaptable (hence don't use this method on hot, free-flowing wells), the drilling rate is quite slow (compared to rotary drills), and the technique becomes time consuming for depths below 1500-2000 ft (450-600 m). Interestingly, in the first few decades of this century, practically all the oil wells were drilled by this type of rig, to depths of as much as one mile.

2. Rotary drilling. This technique is the more common and generally applicable for drilling geothermal wells (Figure 2). The bit more resembles a drill, even though its drilling action may be as much chipping and crushing as it is cutting. The cuttings are removed from the hole by fluid circulated down the drill pipe and up the annulus between the drill pipe and casing. (Reverse circulation is rarely considered appropriate.) Several types of fluids can be employed:
   a) Water or mud: The use of mud is preferred where caving of the sidewalls is a problem but should be avoided in geothermal production zones. The heavier density of mud helps to contain high pressures in gas wells, therefore, the operators of large rotary drilling rigs are accustomed to using it;
   b) Air mixed with water and a foaming agent: This technique further lightens the column of drilling fluid, making it easier for the geothermal water to enter the well bore;
   c) Air alone: Air is used where water or mud is being lost in the formation. If adequate makeup water is available, continuing to drill with water is advisable because it is superior to air in its lubricating and cooling qualities. Air is commonly used for water-well drilling, because air techniques enhance the ability to detect the water-bearing zones. Air drilling does require huge compressors and high pressures. Work around high-pressure pneumatic systems is hazardous, and, consequently, expensive. Air streams carrying the cuttings past the drill pipe create a very erosive environment for the pipe. Frequent replacement of drilling pipe is needed in air drilling operations.

Rotary drilling rigs are much larger, more expensive and require considerably more power than a cable-tool rig. Typically huge, 200- to 400-horsepower engines, one for rotating the drill, often two for lifting the pipe out of the hole, are needed. A mud pump (to circulate the drilling fluid) and a spare, may also be of about 200-horsepower capacity each. Thus, fuel to operate these rigs can cost $500 to $1000 and more per day.

Casing - types and installation

Well casing can be obtained with threaded joints, or it may be ordinary unthreaded pipe which has to be welded together. The latter can be tolerated for shallow wells, but threaded joints are a necessity for deep wells for two reasons: (1) the weight of the casing hangs from the top joint (doesn't apply if the casing is being driven into the ground as the hole is drilled); and (2) the casing may have to be removed if for some reason it won't fit into the hole. The latter may happen because the hole is not straight. There are tools to measure the inclination and direction of the hole, and these should be used periodically during drilling. A clever driller can partially compensate for a deviated hole; therefore, straightness of the well should be specified to the driller. Most drillers have their preferences of how to assemble and install casing. Also, there are service companies to assist drillers in installing long casing strings.

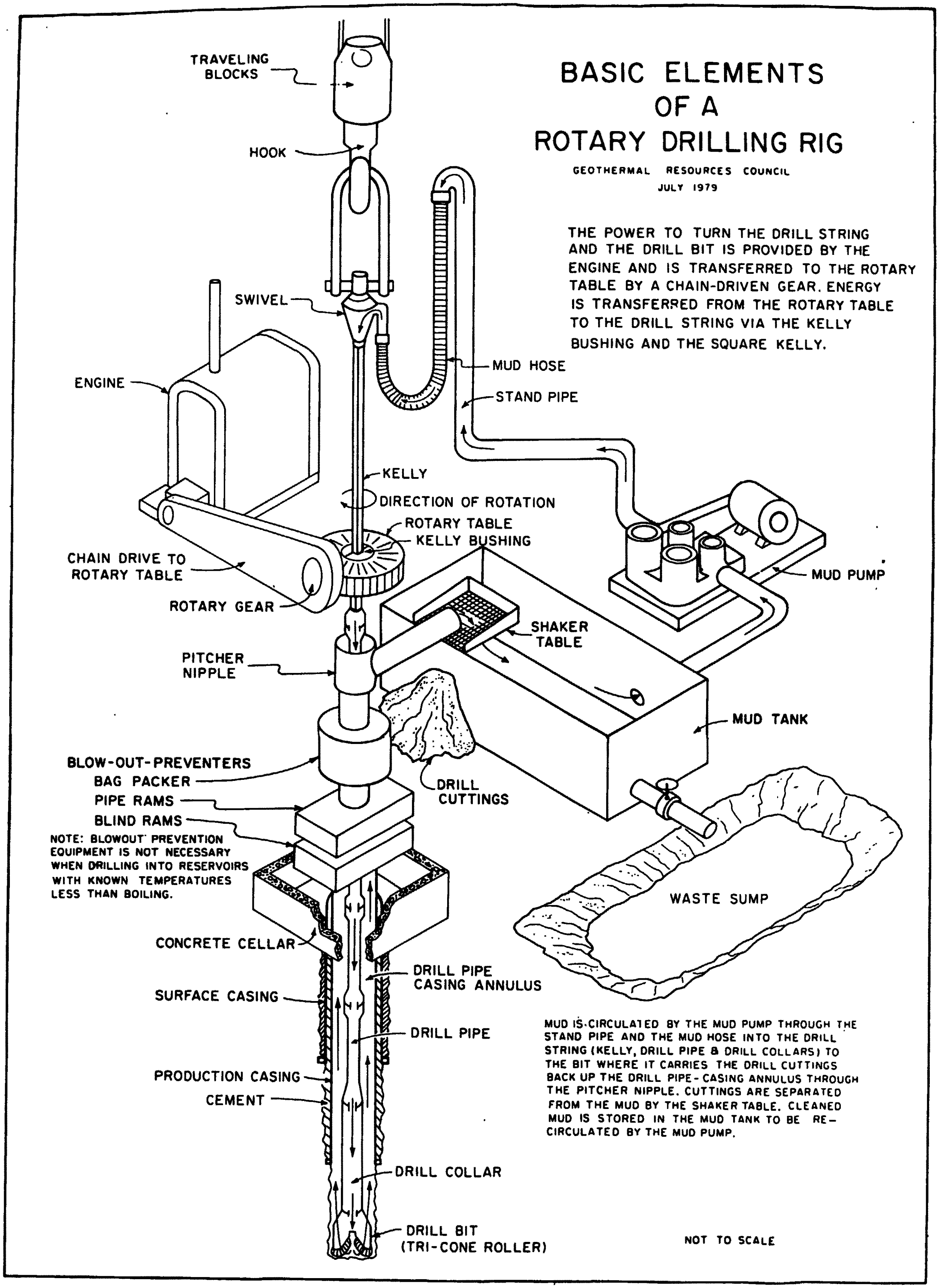

BASIC ELEMENTS
OF A
ROTARY DRILLING RIG
GEOTHERMAL RESOURCES COUNCIL
JULY 1979
THE POWER TO TURN THE DRILL STRING AND THE DRILL BIT IS PROVIDED BY THE ENGINE AND IS TRANSFERRED TO THE ROTARY TABLE BY A CHAIN-DRIVEN GEAR. ENERGY IS TRANSFERRED FROM THE ROTARY TABLE TO THE DRILL STRING VIA THE KELLY BUSHING AND THE SQUARE KELLY.
TRAVELING BLOCKS
HOOK
SWIVEL
ENGINE
MUD HOSE
STAND PIPE
KELLY
DIRECTION OF ROTATION
ROTARY TABLE
KELLY BUSHING
CHAIN DRIVE TO ROTARY TABLE
ROTARY GEAR
MUD PUMP
SHAKER TABLE
PITCHER NIPPLE
MUD TANK
BLOW-OUT-PREVENTERS
BAG PACKER
PIPE RAMS
BLIND RAMS
DRILL CUTTINGS
NOTE: BLOWOUT PREVENTION EQUIPMENT IS NOT NECESSARY WHEN DRILLING INTO RESERVOIRS WITH KNOWN TEMPERATURES LESS THAN BOILING.
WASTE SUMP
CONCRETE CELLAR
DRILL PIPE CASING ANNULUS
SURFACE CASING
DRILL PIPE
MUD IS CIRCULATED BY THE MUD PUMP THROUGH THE STAND PIPE AND THE MUD HOSE INTO THE DRILL STRING (KELLY, DRILL PIPE & DRILL COLLARS) TO THE BIT WHERE IT CARRIES THE DRILL CUTTINGS BACK UP THE DRILL PIPE-CASING ANNULUS THROUGH THE PITCHER NIPPLE. CUTTINGS ARE SEPARATED FROM THE MUD BY THE SHAKER TABLE. CLEANED MUD IS STORED IN THE MUD TANK TO BE RE-CIRCULATED BY THE MUD PUMP.
PRODUCTION CASING
CEMENT
DRILL COLLAR
DRILL BIT (TRI-CONE ROLLER)
NOT TO SCALE

FIGURE 2

A quality-control check is appropriate on the casing, if it is to be subject to conditions approaching its design limit. Many wells have been destroyed from collapse of casing and/or joints pulling apart. Consequently, quality drillers of deep wells reject many pieces of casing, and these rejected pieces are available as low-quality inexpensive casing that might serve adequately for the shallower, lower temperature geothermal wells.

Non-metallic casing has been used in some of the French geothermal wells at temperatures of 120-140°F (50-60°C). These plastic casings (Fiberglas-reinforced) do have temperature limitations and strength limitations (primarily on how much can be hung from the well head) so such casing cannot be used in the hotter and deeper wells. Unfortunately, to date its cost has not been significantly less than steel casing, but it is lighter and easier to handle with small drilling rigs.

1. Anchor casing at the top of the well (conductor pipe). This casing may be pipe 20-80 ft (6-24 m) long cemented into the ground to thoroughly anchor the well against high pressure inside and the punishment of the drilling operation. This casing usually is installed in a concrete-walled cellar (for the bigger and deeper wells) to allow room for the drilling equipment, valves, etc. between the conductor pipe and the drilling-rig platform. Large drilling rigs usually have two 20-ft (6.1-m) sections of pipe installed in the ground near the conductor pipe (the well) to store the next length of drilling pipe and the Kelly (a length of square or hexagonal pipe that mates with the Kelly bushing that fits into the rotary table; Figure 2) during the drilling operations. These are often referred to as the "rat" and "mouse" holes.

2. Surface casing. The next string of casing is usually required by regulation (law) to protect the drinking-water aquifer from contamination by geothermal water. This surface casing might eventually contain the pump turbine. A check with the appropriate regulatory body about the placement is advisable. The surface casing is cemented to the surface with a 2 to 4-inch (5 to 10-cm) annulus between it and the conductor pipe. The surface casing usually extends deeper than that of nearby domestic water wells, and the main valve and various safety valve equipment are attached to its head.

3. Production casing. This casing is the main casing string and protects the sidewalls of the well against collapse and conducts the fluid to the surface. It must also contain the down-hole pump, unless regulations allow the surface casing to be used for this purpose on the lower temperature wells. In that case, a "casing hanger" is used to hang the production casing near the bottom of the surface casing. Casing hangers cost $1000-$10,000 depending on the type and size.

   Multiple strings of production casing may be used if trouble with sidewall retention is encountered during drilling. Casing hangers are used for these situations, thus making it unnecessary to run the new string back to the surface. The cost of buying and setting casing hangers, however, must be considered.

   Figure 3 shows typical well construction.

Production zones

It is important to determine the production area because the solid casing should not extend into it. Because geothermal fluids are essentially indistinguishable from the drilling fluids, one can often drill right through the production zone and not know it. If flow is eventually produced in the well, temperature-logging techniques can identify this zone. However, by that time, the well may be free flowing, and there may be difficulty in stopping the flow so as to install and cement production casing. How can one determine possible producing zones before

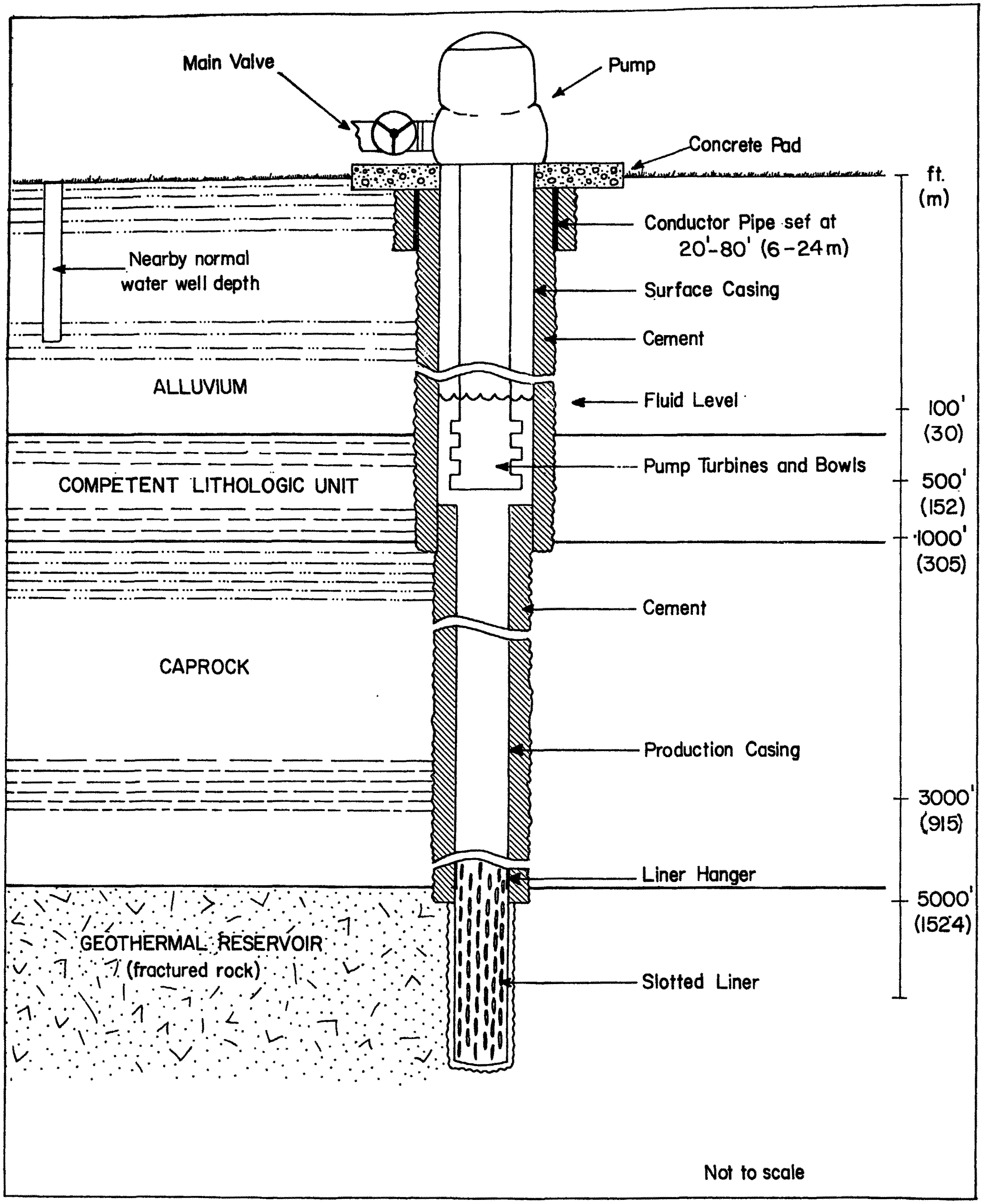


FIGURE 3. Typical design for a low- to moderate-temperature geothermal well.

drilling well on past them? Again, temperature logging appears to be the most reliable method, using high-resolution temperature sensors, preferably on logging cables, that give a read-out at the surface. Examination of the drilling-chip returns can also give a clue as to when the drill enters a possible production stratum. Likewise, a continual monitoring of the quality of the return drilling fluids (such as measuring the fluid electrical conductivity), may also indicate if high-conductivity geothermal water is beginning to mix with the drilling fluids.

Cores. Obtaining cores during production or exploration-production drilling is generally not economically feasible in terms of identifying the production zones. Cores that are randomly taken and represent only a small fraction of the total hole will have limited practical value because they represent such a small fraction of the total hole depth.

Protecting the production zone. The producing zone in oil wells is often cased and cemented, then holes are shot through to allow the desired fluids to enter the well. This technique can be used in geothermal wells which are producing from homogeneous formations where the permeability is all due to intergranular porosity. This technique is unsuitable for formations which produce partially or completely from fractures in the rock. If the shot holes do not fortuitously penetrate the fractures, no production will be realized from these fractures. Therefore, the majority of geothermal wells, those depending on fracture permeability, need to keep all cement or types of materials that have cement-like properties, away from the production zone.

To finish the production zone, a screen or slotted liner (a liner is a piece of casing not cemented in place) can be hung from a casing hanger at the bottom of the production casing. If the production zone is in consolidated rock strata, a liner may not be necessary. In any case, it is desirable to drill a hole somewhat deeper than the known production zone so that any material that does cave away from the walls has a "wastebasket" section to fall into instead of accumulating in the production zone.

Cementing casing

The casing is usually cemented by pumping cement down the inside of the casing and up and around the casing, filling the annulus between casing and well bore, or between casing and existing outer casing. This requires that the end of the casing be fitted with a check valve made of soft material that can be easily drilled out later. The techniques for cementing casing have been well established and are common to the oil and gas and water-well industries. Geothermal wells present additional problems, however, for which the traditional cementing techniques are inadequate. The principal problem is created by temperature hardening the cement prematurely. This effect, however, can be retarded chemically. But if the retardation is too long, the cement may be diluted by naturally convecting waters in the formation; or if redrilling is begun, the casing may be jarred breaking the unhardened cement. Failures during or after the cementing process have been some of the more frustrating problems encountered in the hot-water geothermal wells.

It is important to have the cement bonded to the casing. This bond can be checked by a sonic technique. Such a check requires a logging service, and it is expensive. If the cement is found to be inadequately bonded or is known to have gaps, then remedial action may be needed (depending on the severity of the thermal stress that the casing will see and/or the requirements of state or federal regulatory agencies). Such remedial action may require shooting holes into the casing and squeezing cement into them. Again, this is an expensive operation, fraught with difficulties. It is obviously desirable to have a successful cement job on the first attempt.

Thermal losses can be significant in direct-heat application if the resource temperature is marginal to begin with. Losses in heat traveling up the well can vary from a few degrees to 10-15°F (5-8°C). The problem is most severe for deep wells penetrating convecting cold water aquifers. To date, there are no examples of attempts to reduce the heat loss significantly. A possible method is to add material to the cement that will enhance its thermal resistance. Another possibility is to anchor the bottom of the surface casing with cement and fill the rest of its annulus with a rigid, expanding foam. This latter method offers tremendous potential for reducing heat loss. It must be approved by the state or federal regulatory agency, and the well head must be designed to handle the casing expansion. Expansion-compensating well-head equipment is commercially available. (Though the use of foam between the surface and production casing has been discussed by many organizations, the technique has yet to be tried in practice.)

Problems in geothermal drilling

Drilling of geothermal wells involves the same types of problems that plague water-well and oil-well drillers: broken bits, broken drill pipe and "lost" tools, stuck tools, etc. However, geothermal drilling has two concerns which essentially demand contradictory approaches to drilling technique. These must be assessed for any particular well-drilling situation, and the most critical concern at that point in the drilling operation is to allow one to take precedent over the other. The two concerns are as follows:

1. Avoiding the sticking of the drilling tools in the hole caused by sidewall sloughing away and collecting around the bit. Caving in of the hole is the bane of drillers and rig operators and is most likely to occur in the loosely consolidated formations in the first few thousand feet (300 m's). Generally, at greater depths, hundreds of years of high pressure and moderate temperature have cemented or consolidated the sediments. The common methods to avoid this problem are to use heavy drilling fluids (called mud) having 1-1/4 to 1-1/2 times the density of water and approaching the density of the formation and the lithologic pressure. Flow rates for these drilling fluids must not be so high as to erode the side walls. The use of heavy drilling fluids accomplishes the following:
    a) Prevents caving;
    b) Floats and removes the cuttings more effectively;
    c) Seals the walls from loss of drilling fluid (very important when the mud is expensive);
    d) Suspends cuttings for longer time when the circulation is stopped and the drilling bit is removed from hole;
    e) Lubricates and cleans the cuttings from the bit.

2. Avoiding the use of heavy or unnatural fluids in the suspected production zone. This requirement clashes with (1) above. Yet some of the very reasons for using heavy drilling fluids, as in (1), are the same reasons that make it difficult to identify the geothermal-producing strata. For instance:
    a) Heat in the geothermal zone may help solidify the drilling mud in the fractures, and the mud may actually develop the qualities of a cement;
    b) Chemical reactions, especially at the higher temperatures, may contribute to the mud sealing the pores in the rock formation;
    c) The weight of the mud can prevent the geothermal water from entering the hole, thus the driller has no clue that he has encountered the resource.

The latter concerns are extremely important in geothermal drilling, but of no concern in oil and gas drilling, where, as soon as the hydrocarbons come to the surface with the cuttings that contained them, the hydrocarbon "sniffer" will detect their presence. The oil and gas driller then knows he has hit a potential producing zone. The geothermal driller gets no such clue from his zone. The best detection technique is to conduct a high-resolution temperature log, from which he might possibly deduce subtle temperature changes and a potential geothermal strata, but the chances are slim if drilling is done with mud. Hence, in the production zones (suspected or otherwise), the driller may just have to take his chances, drilling with water or with water made lighter with air, hoping that the sidewalls will not cave in on him and that geothermal water will leak into the well bore. Keeping the fluid circulating and getting the drill string out of the hole as quickly as possible (when circulation is stopped to remove the bit) are extremely important.

Safety considerations

1. Temperature. A temperature hot enough to scald (above 140°F, 60°C) requires having face shields, wet suits and insulated gloves available. Temperatures above boiling should be treated with the respect given to any steam system, with applicable codes (Section VIII of ASME, etc.), personnel protection, and operating procedures to prevent accidents.

2. Free-flowing (artesian) wells. Two conditions can create water flowing free at the surface. The geothermal reservoir could be fed from a higher elevation. At the location where the well is drilled, there could be a layer of cap-rock (see Figure 4). As soon as a drill breaks through this cap-rock stratum, the pressure will be that of the higher elevation, provided the well bore is not sealed and is not filled with heavy mud. If the well is fed from a higher elevation, no amount of cold water will kill the well once it starts flowing. These wells present special drilling problems during casing and cementing. It is thus desirable to complete these operations before drilling through the cap-rock and into the resource production zone. If such preparation is not possible, the use of heavy muds may be considered. Such practice is common in the oil and gas industry, but is generally ill-advised for geothermal wells (see Problems in Geothermal Drilling, above). Alternative methods are to back-fill with sand (and to drill the sand out later), or to kill the well with salt water with density up to 1.2 times the density of ordinary water if a suitable means of avoiding environmental contamination with salt is available.

   The second condition leading to artesian well-head pressure is a density difference from a hot-water column in the well vs. a cold-water hydrostatic head above the geothermal reservoir. The following table lists the pressure difference with respect to 68°F (20°C) cold water, per 1000 ft (305 m) of vertical height.

102°F = 39°C	2.8 psi (19 kPa)
153°F = 67°C	8.7 psi (60 kPa)
193°F = 89°C	14.5 psi (100 kPa)
212°F = 100°C	17.8 psi (123 kPa)
240°F = 116°C	22.7 psi (156 kPa)
281°F = 138°C	31.0 psi (214 kPa)
302°F = 150°C	35.8 psi (247 kPa)

   Since 1.0 psi (6.9 kPa) will elevate water 2.3-2.5 ft (0.70-0.76 m; depending on the temperature), the hot leg can stand substantially higher than the normal water table, perhaps enough to make the well free flowing at the surface. This type of well can be killed by pumping cold water into it. It can be restarted by air-lifting or by swabbing (pulling out a loosely fitting piston at a rapid rate).

3. Casing thermal expansion. The expansion differential between the casing and the material which it contacts (the cement, for instance) is a significant problem, as is the sole thermal expansion of the casing itself if it is allowed to expand freely. Steel casing, for instance, with a thermal expansion coefficient of

$$6.7 \times 10^{-6} \text{ per °F } (3.7 \times 10^{-6} \text{ per °C})$$

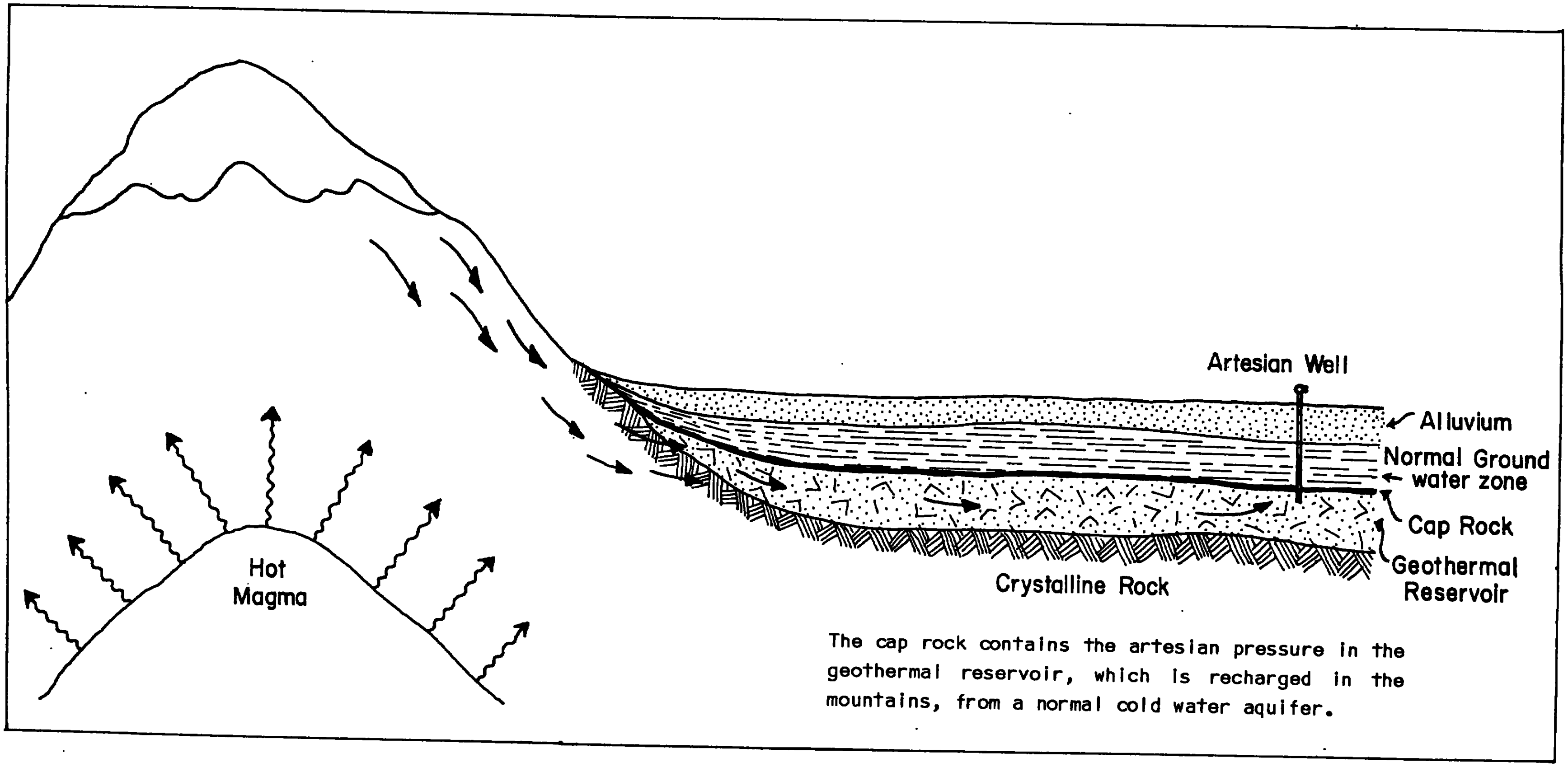


FIGURE 4. The source of artesian pressure in wells.

will expand by 8 inches over every 1000-ft length for every 100°F of temperature change (20.5 cm/305 m/ 38°C). Its relative expansion, with respect to rock or cement, is about two-thirds of this amount.

If one tried to constrain a 1000-ft (305-m) length of casing 13-3/8" OD by 3/8" (34 cm x 0.95 cm) thick, the stress would be approximately 20,000 psi (1.38 x 10^5 kPa), and the force to constrain this expansion would be 318,000 lbf (1410 kN)--all this for just 100°F (38°C) change in temperature. The effects for longer strings of casing and for larger changes in temperature are proportionately greater. These effects are insignificant in ordinary water wells and usually of little concern in oil wells. But in geothermal wells, casing expansion, even during the casing installation operations, must be carefully considered to insure the inclusion of the appropriate allowances and clearances.

The most common practice today is to cement the entire surface and production casing thoroughly in place with a tight bonding cement. Afterwards, casing expansion can be ignored, unless the bond breaks. To minimize this possibility, operation of the well throughout its lifetime should be so planned as to limit the number of "ratcheting" thermal cycles---i.e., keeping the well hot even when it is not being used.

4. Containment of drilling fluids and well production. Most environmental regulations will not allow disposal of either drilling fluids or the produced geothermal fluids on the surface until it is proven that these do not affect the local environment. Therefore, all drilling operations must consider using hold-up ponds (reserve pits) and the necessary mechanisms to direct the fluids into these pits. Also, a reserve supply of cold water must be available for makeup water, if needed, and for cooling the well should an emergency arise.

5. Blowout preventers. This term is perhaps overused and is popular in the oil and gas industry and for steam geothermal wells. In general, blowout preventers are those mechanisms attached to the well head which can shut off the flow out of the well, even during drilling. These mechanisms are:
   a) A set of blind rams (gate valves) used to shut off the well when not drilling;
   b) A set of pipe rams that can close around the drill pipe;
   c) A rotating head that forms a seal around the drill pipe but allows it to turn freely;
   d) A check valve at the bottom of the drill pipe to prevent fluids from entering the pipe; and
   e) An inflatable rubber sleeve that can close tightly around drill pipe or any other device hanging in the well.

   Wells that are not free flowing or will flow only lukewarm fluids (say below 140°F, 60°C) may require no more than the standard gate valve. Figure 5 shows some typical well-head installations and blowout preventers.

Costs of drilling

The following approximate costs are presented for rough estimating purposes. All costs are drawn from 1979 quotations.

Drilling rigs.

1. Rotary rigs: These rigs vary in size, from truck-mounted units that can be quickly dismantled and transported, to large rigs capable of reaching depths of 20,000 ft (6 km) or more. The latter are seldom used in geothermal drilling. The following tab-

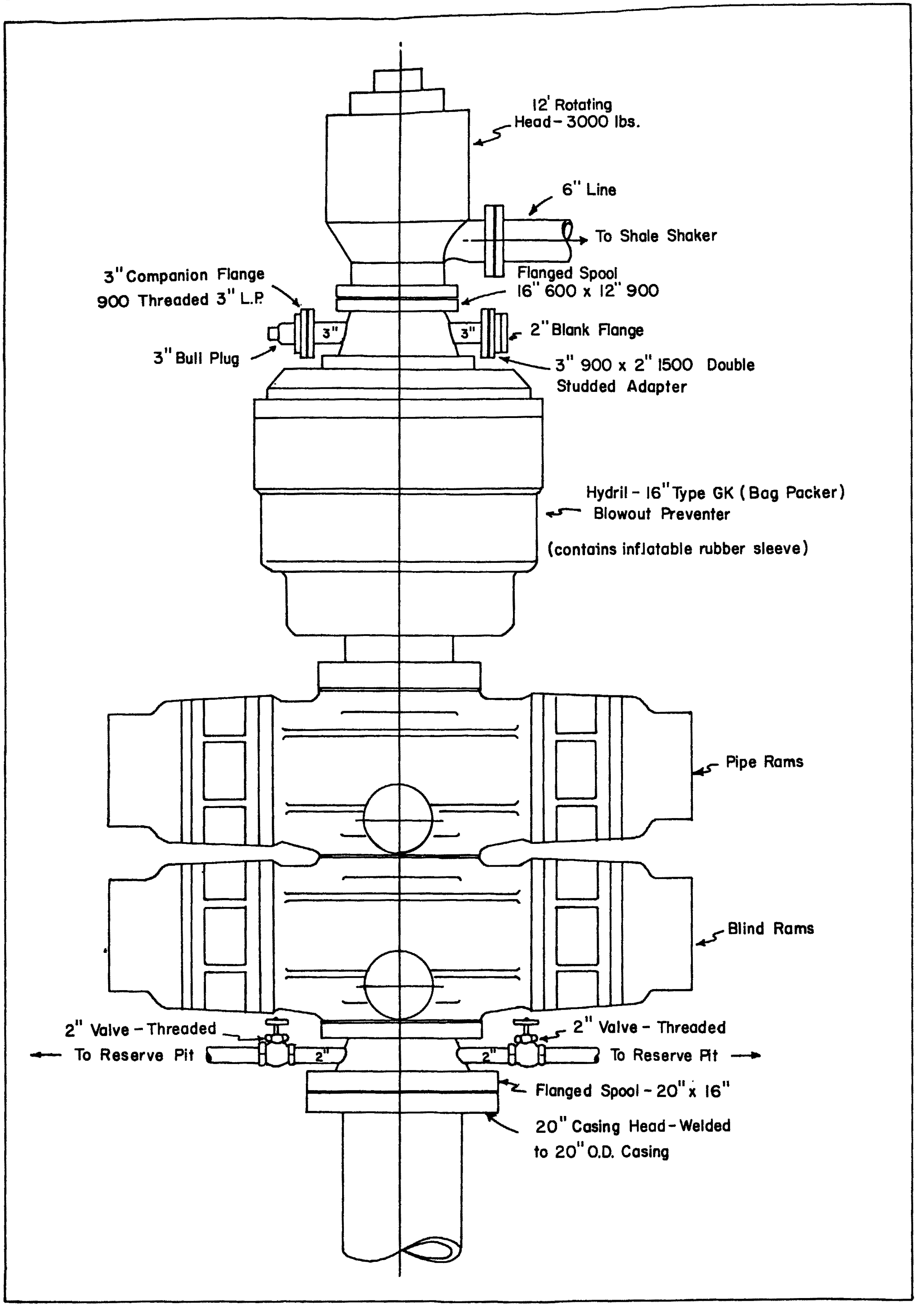


FIGURE 5. Containment equipment--blowout preventers. Typical for use on high-pressure wells.

ulation assumes a depth capability of at least a 6-inch diameter bit (15 cm) and 5-inch (13 cm) casing.

a) Truck-mounted rigs:

1) Depth capability of 1000-1500 ft (305-450 m)

Day rate (24 hours)	\$800-\$1500
Move-in and move-out costs	\$2000 (approx)

2) Depth capability of 2000-4000 ft (610-1220 m)

Day rate	\$2500-\$4000
Move-in and move-out costs	\$20,000 (approx)

b) Medium-sized rigs (capable of drilling to 10,000-15,000 ft, 3048-4572 m): Medium-sized rigs generally have hoist capability of 200,000-300,000 lbs (90,000-136,000 kg) and may take 30 or 40 truck loads to get all the equipment to the site. Their depth capability, using a 6-inch (15 cm) bit, significantly exceeds geothermal requirements (10,000 ft, 3 km). A 300,000-lb (136,000 kg) hook capability can handle 8000 ft (2.4 km) of 9 5/8-inch (25-cm) casing.

Day rate	\$4000-\$6500
Move-in and move-out costs	\$100,000 (approx)

c) Large rigs (capable of drilling to 30,000 ft, 9144 m): These rigs generally exceed geothermal requirements, with hook-load capabilities in the range of 1/2 million to 3/4 million pounds (0.23-0.34 million kg).

Day rate	\$10,000-\$15,000
Move-in and move-out costs	\$250,000 (approx)

2. Cable-tool rigs. These rigs generally cost \$500-\$1000 for a 10-hour day. However, many cable-tool operators will bid a footage rate, which will be approximately \$1.50 per inch diameter of hole per foot of depth (\$1.93/cm/m) to 500 ft (152 m, nominally), with higher rates for greater depths.

Casing. Approximate FOB prices for standard-sized well casing:

20" threaded	(50.8 cm)	\$30/ft (\$82/m)
13 3/8" threaded	(34.0 cm)	\$20/ft (\$59/m)
9 5/8" threaded	(24.4 cm)	\$13/ft (\$43/m)
6 7/8" threaded	(17.5 cm)	\$ 8/ft (\$26/m)
20" regular	(50.8 cm)	\$20/ft (\$49/m)
12" regular	(30.5 cm)	\$13/ft (\$33/m)
8" regular	(20.3 cm)	\$ 9/ft (\$20/m)

Casing shoes typically cost several hundred dollars each.

Drilling bits and other expendable equipment. A rotary drilling bit from 6 inches to 12-1/4 inches (15-31 cm) may cost between \$500 and \$5000. The toothed bits are the least expensive. The tungsten carbide "button" bits with sealed journal bearings are the most expensive.

A bit will generally last for 100-1000 ft (30-305 m) of drilling, or from 12-30 hours, though some of the newer, advanced sealed, journal-bearing bits may be run for as much as 100 hours. The bit life depends on formation hardness, weight applied on the bit, and on the actual cutting rate. Manufacturers specify the nominal rotation speed and weight applied to the bit for best operations.

Services. Various services may be needed during a drilling operation. A few of these are listed below:

1. Geologists and a mud-logging truck to examine and record the drilling-chip rock type, and such other information as may be gleaned from drilling returns.
   Cost: $300-$400/day

2. Casing crews - About $2 per foot ($6/m) of casing installed ($2000 minimum).

3. Complete logging services - Minimum cost $3000. However, temperature logging only costs $500-$1000 each time the well is logged with a rig and a crew already on site. Figure $1 per mile ($0.60/km) travel costs.

4. Fishing services - if tools are lost in a hole (typically $2000/day).

5. Coring services - The diamond bit used for coring costs between $7000 and $10,000. In addition, a technician and a core barrel are rented.

6. Turbine drilling services for sidetracking or whipstocking - These services usually include an engineer on site.
   Minimum costs: $7000.

Time required to drill

1. A cable-tool rig will drill as much as 5 ft (1.5 m) per hour, to depths up to 500 ft 152 m). The rates become quite slow at greater depths or in hard formations.

2. A rotary rig can be expected to drill 500 ft (152 m)/day in soft formation. But in hard formations, the progress might be as little as 100 ft (30 m)/day (a 24-hour day).

As the well gets deeper, one must then figure the time lost in "trips" to bring the bit out of the hole, to replace the old bit, and to return to the bottom again. For instance, a round-trip from 4000 ft (1220 m) can occupy 3 to 7 hours, depending on the experience of the crew.

The contingency

Any cost estimate involving construction includes a contingency for inaccuracies of the estimate and the unexpected delays that necessitate changes in design or construction methods.

Although drilling, by its very nature, explores the unknown underground, many direct-heat applications projects need only one or several wells, not an entire field of wells. The contingency recognizes that you are dealing with the unknown and problems that do occur may be many thousands of feet away at the bottom of a drill hole. The contingency must adequately account for these conditions; it should not be merely a hedge for inaccuracies of the cost estimate. A minimum contingency of 25% is recommended.

Typical drilling costs for geothermal wells are plotted in Figure 6.[2] These figures are taken from those derived for wells that are low-to-moderate temperature (The Geysers field and Imperial Valley wells are not included). In general, these represent total costs, including unusual

[2] The authors wish to acknowledge the assistance of the U.S. Department of Energy, Idaho Falls Office (Robert Chappel) and the Earth Science Laboratory of the University of Utah Research Institute for portions of this data. Since some of the well costs were supported by federal funds, the costs may differ somewhat from wells drilled with private funding; however, the difference is not likely to be more than 40%.

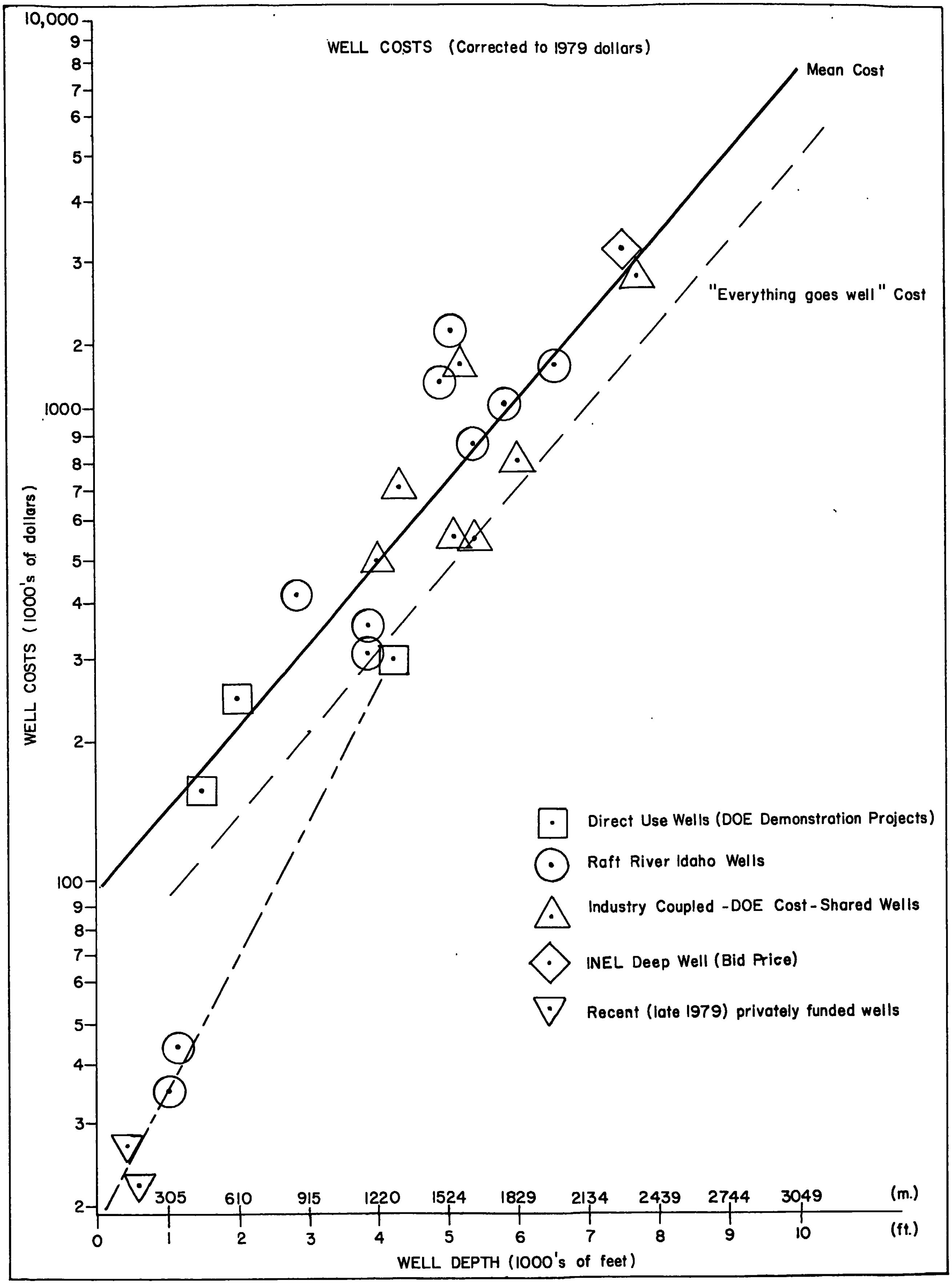


FIGURE 6. Typical drilling costs for geothermal wells (corrected to 1979 dollars).

problems that developed and may be first-of-a-kind problems in some cases. Cost incurred by the owner or developer for his salaries or for consultants are generally not included in the well costs. It is apparent that there are two trend lines, one for very shallow, easy-to-drill wells, the other for the more conventional wells. These figures should serve as a useful guide for rough estimating, since all results have been escalated for inflation to equivalent 1979 dollars.

DRILLING REGULATIONS

Temperature

State regulations of geothermal production often begin at a given temperature. Temperature is an easy method of designating the point of demarcation for the more restrictive geothermal regulation. In the eastern states any depth or temperature allowing heat extraction would probably be covered by a state oil and gas commission or other regulatory body that reviews oil and gas exploration and production.

Conventional water rights and drilling regulations

In the more arid west, if temperature and depth limits set by state regulation are exceeded, geothermal-production permit or geothermal-injection permit may be required. Above that depth of demarcation, a water right is required since western states have developed a comprehensive system of water rights both judicially and administratively. This relation between water right and geothermal use varies somewhat from state to state.

Water rights protect the user but geothermal regulation protects the resource. Most western states have water rights based on a "first-in-time, first-in-right" principle. Geothermal regulation (permit) sets the standards for blowout prevention equipment (BOPE), casing requirements, logging, withdrawal quantity, data and other construction requirements and management tools. These regulations include geothermal exploration wells, production wells and injection wells. It is generally recommended that both water rights and geothermal permits be obtained.

Federal regulations on federal leased lands

Federal leased lands have many uses. Just a few such uses are: fish and wildlife habitat, silvaculture, grazing of livestock, wild and scenic rivers, primitive areas, sports and recreation, and mining and related claims.

The Bureau of Land Management of the Department of Interior is the custodial agency of federal lands. Leasing requirements are established by Congress. The U. S. Geological Survey controls the geothermal rights and supervises the drilling and production operations. The regulations require an environmental assessment, construction criteria, on-site inspection and payment for heat used, usually for a 10% royalty. Leased land is obtained through competitive bidding for the obvious geothermal lands (Known Geothermal Resource Area, KGRA's). The procedures are stated precisely in the Geothermal Steam Act of 1970 and its implementing rules and regulations, Chapter II-Geological Survey, Department of Interior, Parts 270 and 271.

State regulations

State leasing requirements on state-owned land are similar but usually less stringent. Generally, the state land department awards the leases and governs such geothermal uses through the oil and gas regulations of the state.

Driller licensing

The classification of well drillers depends on the type of well. The three classes are the licensed water-well drillers, the mineral (slim hole) test-well drillers, and the oil- and gas-well drillers. All three types have drilled geothermal wells.

Each state issues licenses to water-well drillers and the general public can review the driller files. State oil and gas regulatory agencies regulate oil- and gas-well drillers, review the drilling prospectus and inspect the sites. Mineral slim-hole drillers may not be required to have a license or be reviewed by either of the above.

Equipment and company resources become a ruling factor in geothermal well drilling. Oil and gas drillers have knowledge, equipment and company resources, but these drilling rigs are probably too expensive for shallow or even intermediate-depth (2000 ft, 610 m) geothermal wells. A licensed water-well driller can drill a shallow geothermal well if his rig is appropriate in size and quality and his company has the resources to complete the job in case of difficulty. As a rule of thumb, a large water-well drilling company may be considered even for wells expected to exceed 2000 ft (610 m). Below that depth, technical problems may dictate a larger type oil and gas rig and driller.

Geothermal-well drilling can be dangerous and expensive because of the depth of the well, the high pressure and temperature, leaks and possible contamination of groundwaters and surface waters. These problems generally increase dramatically as depth and temperature increase. Thus, the lower temperature, direct-heat application wells may have negligible problems when compared to those of the deep, high-temperature wells for electric steam power plants.

Liability

The owner, developer and driller are liable for infractions of the law and possible damage. More particularly, they must answer to conditions of permits, contracts, leases and to the judicial system if parties submit claims of damage.

Provisions for production testing

Production drilling must waste geothermal fluids temporarily. State agencies generally require some guarantee of protection of surface and groundwater from possible contamination by a waste product. They monitor the water quality if there is direct discharge to surface water sources or to lined containment ponds.

Water quality governs the methods of disposal. Water-quality standards may be lowered because of the temporary disposal of the geothermal product being tested. Sampling and consulting the regulatory agency before selecting the appropriate disposal method are important. Early sampling could save rig time in constructing lined ponds.

Geothermal fluids may be disposed during production testing by the following methods:

1. Waste directed to a known water course after being cooled if quality is acceptable;

2. Waste disposed on the surface, such as irrigation;

3. Waste disposed below the surface to shallow strata ponds. Quality water is injected through the pond bottom to a dry strata;

4. Waste held in a lined evaporation pond. This method requires a pond with a large surface;

5. Waste injected into a well to an authorized strata.

Suggested reading list.

1. State codes--specific sections applied to geothermal and water law,

2. Rules and regulations of state agencies,

3. Federal Geothermal Steam Act of 1970 and USGS rules and regulations (see Chapter II, Parts 270 and 271),

4. State leasing requirement (usually obtained from the state land department).

5. A survey of environmental regulations applying to geothermal exploration development and use--Environmental Protection Agency. These are currently being drafted by the agency.

DISPOSAL OF USED GEOTHERMAL FLUIDS

The direct use of geothermal waters for space heating or for industrial-process use requires large flows of water. For example, the Oregon Institute of Technology at Klamath Falls requires an average pass-through of 250 gpm (16 l/s) to heat 500,000 ft^2 (46,000 m^2) of floor space in 8 buildings. Typical large industrial-process heating applications require flows of 500 to more than 1000 gpm (30-60 l/s). With multiple users in an area, demands for geothermal fluids could easily total 10,000 gpm (600 l/s). After the useful heat is extracted from these fluids, there must be an economically and environmentally acceptable method of disposing of them.

In the past, the most common practice has been to reject the fluid into the nearest water course. In most cases, this practice has not caused problems. However, with the anticipated increase in uses of geothermal energy, the ability of surface streams and lakes to absorb these waters will soon be passed, eventually causing noticeable environmental deterioration. State and federal laws now prohibit or severely restrict this practice of dumping, so other forms of disposal have to be used. Two alternatives exist: surface and subsurface disposal.

Surface disposal

Disposal by dumping is no longer legal except in rare cases where flows are minimal and will not damage the downstream environment. In some cases, beneficial downstream use of the geothermal fluid can be considered, depending on the tolerance of the use and the quality of the geothermal fluid. It may be possible to remove or to lower the amount of offending elements, thereby improving the quality of the geothermal fluid for a variety of downstream uses. However, for most projects, treatment of the geothermal discharges would not be economically feasible.

Ponding is the other surface-disposal alternative. Ponding is probably the best tool for short-term activities such as well testing. Long-term ponding has been used where level land is available. With ponding, the fluid is ultimately disposed of by evaporation or by leaching, or a combination of both. Leaching ponds are viable only if usable groundwaters are isolated from the leachate and only in areas where there is a high rate of evaporation. The unique combination of circumstances to make ponding a practical long-term disposal technique may be unusual, so its application could be very limited.

Subsurface disposal

Waste can be disposed below the surface either by injecting the geothermal fluid away from the production reservoir or injecting it into the producing reservoir. In practice, it is difficult to find deep zones of sufficient permeability and porosity to absorb the large volumes of fluid from a geothermal operation, except for the producing geothermal zone. In areas of high permeability near the surface, this disposal method has been successfully applied. Returning the spent geothermal fluid to the production reservoir has proven to be a successful solution to several potential problems in addition to getting rid of the effluent. By injecting into the producing reservoir, the consumptive use is decreased or eliminated; the useful life of the field is extended by mining the heat from the rock, and the potential for subsidence is reduced.

The benefit of reduced consumption is obvious, as the same water can be reused many times to transfer the heat to the surface. This method can extend the useful life of the field through conservation of both the water and the thermal energy. Under nearly all reservoir conditions, there is more heat stored in the rocks in the reservoir than in the water, so recycling the water washes more heat from the rocks. The life of the reservoir can also be extended by returning the still energy-laden water to the reservoir rather than require its recharge from water outside of the system that is at ambient surface temperature. In practice, most geothermal installations utilize only 10-25% of the heat contained in the water and reject the rest. If this heat normally rejected were returned to the reservoir, less total heat would be required over the life of the field. Figure 7 illustrates a comparison of energy and water flows using the example of three schools in Klamath Falls that have return-water systems.

There is a serious concern that the returned geothermal fluid might cool the reservoir. In most cases, a change in temperature of a few degrees does not significantly affect a space- or process-heating use and the benefit of extending the life of the field makes injection a good trade-off. In practice, a history of fields that utilize injection shows there are no measurable changes in the fluid temperatures over time. In a field where any reduction in reservoir temperature would have detrimental consequences, the possibility of returning the water at a distance from the production wells, thereby allowing a long path to pick up heat, has been considered in several cases. Figure 8 shows an example of the effect of reinjection for an operation moving 1000 gal/min (60 l/s) of fluid from a production to a reinjection well. As can be observed, it will take many years for the first streamline of fluid to reach the production well 4,000 ft (1200 m) away. But that hydraulic front will not be cold when it reaches the production well, for the rock will have heated it to within a few degrees of the original reservoir temperature. Of course, the assumption of a homogeneous formation will rarely apply in regions where there is significant faulting. In those cases, reinjected fluid will travel along the faults and fractures. The connections, or lack of connections, between the production and reinjection wells can dramatically alter the time required for the "cold" hydraulic front to reach the production well, either decreasing or increasing that time depending upon the orientation of the fractures.

Disposal regulations

1. State regulations: Geothermal developers must comply with all regulations regarding disposal of waste waters. For new developments, this makes surface water discharge very difficult; in fact, it is usually unacceptable. Subsurface disposal is the preferred

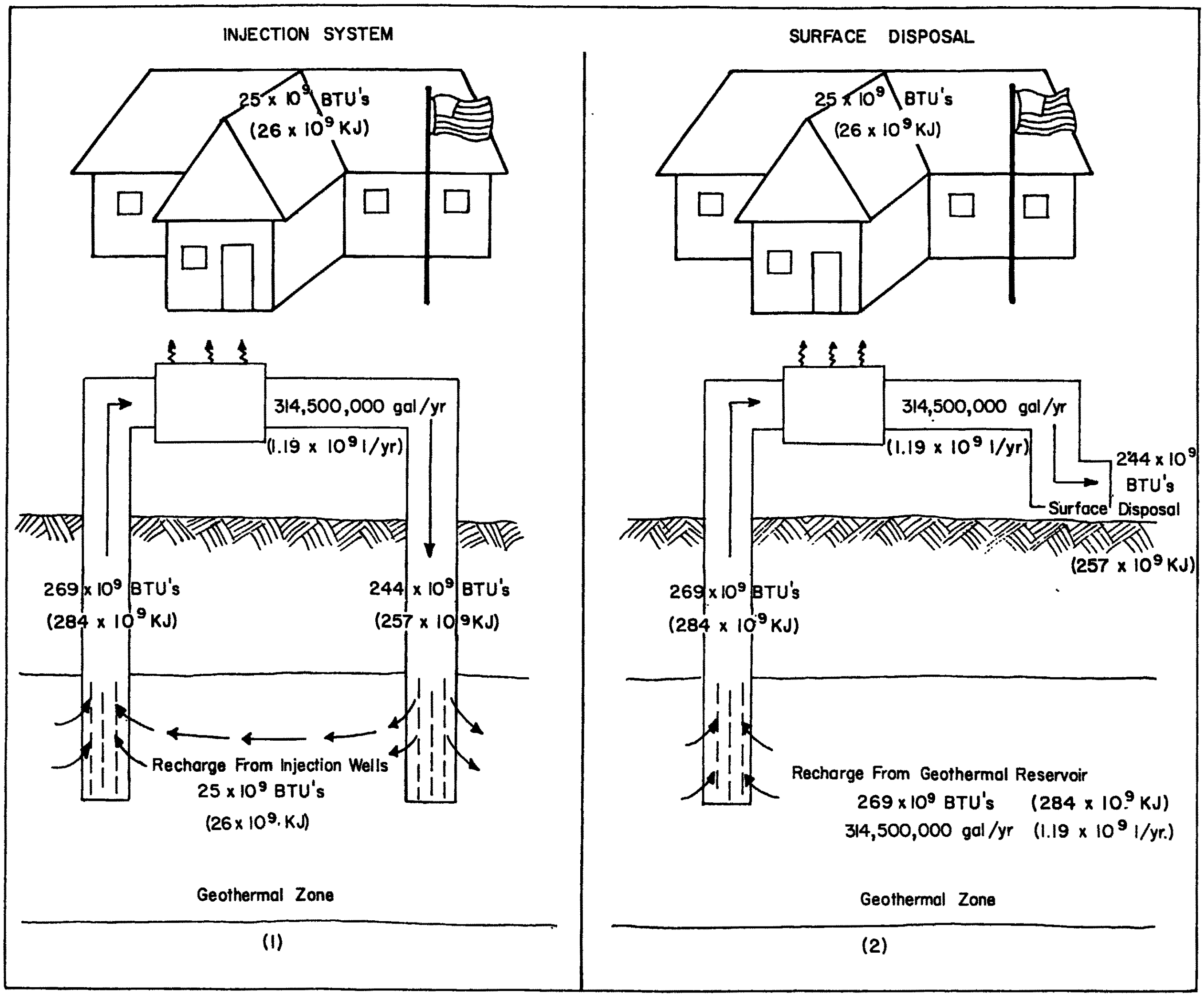
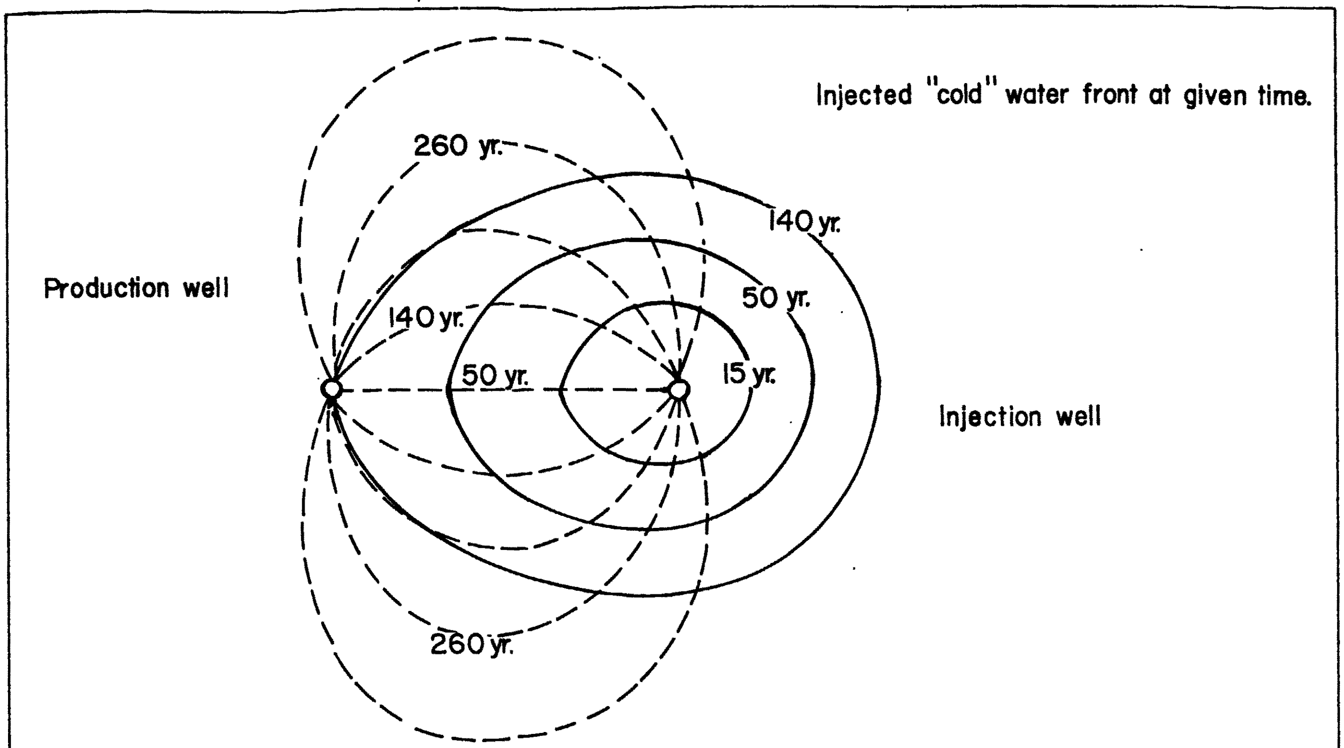


FIGURE 7. A typical comparison study of two methods of disposal of geothermal fluids, showing one-year energy and water requirements for two schools in Klamath Falls, OR utilizing (1) an injection system and (2) a surface-disposal system.



Conditions: Flow = 1000 gallons per minute (60 l/s) from production well, to the surface, and back into the injection well. Aquifer is 250 ft. thick. (76m) Formation effective porosity is 20%.

FIGURE 8. Migration of "cold" water from injection well back to production well.

method, and at this time most states have not formulated any rules beyond treating geothermal effluent as groundwater. Oregon is presently considering regulations making injecting of geothermal effluent the preferred system; but if the developer shows damage will occur, other techniques would be considered.

2. Federal regulations: For geothermal in federal lands, return of the fluid to the producing reservoir is the approved method of disposal. Injection into other areas can be accepted if it is shown not to have harmful effects on domestic water resources. At present, geothermal injection regulations have not been issued by the EPA (as of December 1979).

Liability considerations

There is always a potential of damage to other resources by unanticipated contact with the geothermal return waters. Both state and federal regulations describe procedures and checks for subsurface disposal systems. It will be up to the operator to adhere to these regulations and to monitor the injection wells. By adhering to these practices, an operator will be protecting himself against claims for damages that might be instigated.

Cost considerations

Costs for injection wells are probably similar to costs for production wells of similar size and depth. In addition, pipelines and monitoring equipment will be necessary. In general, an injection well can accept more fluid than a production well can deliver. Thus, fewer injection wells are needed. However, actual operating experiences with injection have been few, and chemical precipitation problems in the well bore are of concern. It is best to keep the geothermal fluid under pressure all the way from the production well head to the injection well head.

Unitization

In general, geothermal fluids will need to be reinjected because their chemical nature will not meet today's stringent environmental controls for surface disposal. But most direct-heat projects will involve relatively small amounts of energy and hence small amounts of fluids. The required number of wells, both production and reinjection, will be limited. Nevertheless, if the area is a good source for geothermal fluids, attempts will be made to develop adjacent properties for similar direct-heat applications. Even the initial developer may find it necessary or desirable to put the production wells on property of one owner and the injection wells on property of a different owner.

Under these varying circumstances of multiple land ownership and many small developments of direct application of geothermal, the choice of which properties have the production wells and which have the injection wells may be arbitrary. The questions are:

- Which owner collects the royalties for the production wells?
- Does the owner of the land on which the reinjection wells are located receive payment?
- Will the production and reinjection wells affect, over the years, the thermal quality of the resources of adjacent property owners?

These questions can largely be avoided by unitizing the area to be affected by the development. Unless specific information to the contrary is available, one may assume that the reinjection fields are just as necessary and valuable as the production fields, and all the owners in the unitized area share proportionately in the royalties. Unitization should be accomplished early in the development program to avoid controversies.

ENVIRONMENTAL CONSIDERATIONS

Surface land use

1. Access road: To begin construction of any geothermal well, the driller and his rig must have access to the immediate site as well as access to the siting of the projected uses. The access road will require reasonably large radius curves with moderate grades and curves since the drill rig and other equipment will be long, heavy loads. Bridges and culverts for stream crossing should be adequate to support the rig, but need only be strong enough to support lowspeed infrequent usage by the heavier machines. Stream crossings may require a permit from the state water resources agency. Road widening and curve restructuring would require permits or leasing from the private land owner or a state or a federal agency such as the State Land Department, the U.S. Bureau of Land Management or the U.S. Forest Service.

2. Drill site. The drill site must be sufficiently level and cleared for the drilling rig and for a helper truck carrying drill pipe, casing, bits, etc., and the site also must have additional room for mud pits, holding ponds and vehicle parking. The required size of the area is a function of the size of the drilling rig. However, from 1/4-acre to 2 acres (0.1-0.8 ha) of land is a typical range. If the well is to be tested, a holding pond may be necessary, depending upon quality of the geothermal and local considerations. In areas of high relief, slope failure and landslide possibilities should be considered when the drill site is being prepared.

   After drilling is completed and the well is brought into production, the site should be restored. A production well requires very little space. When the well is completed, there is very little visual evidence, only the well casing above ground or in a concrete bunker (cellar). If it is necessary to pump the well, a small pumphouse may be constructed or a cellar can be excavated. In all cases, the restoration should leave sufficient room around the well to bring in a workover rig required for maintenance or repair work.

3. Drilling operations: The drilling operations can be offensive in populated areas as well as in unpopulated recreational areas. Careful use can reduce the noise, dirt, and dust. Roads may be watered; drilling operations can be scheduled to meet such local restrictions as no noise at night in residential neighborhoods all trash should be kept in trash containers; oil waste from machines should be contained and appropriately disposed of in proper containers.

4. Pipelines: The pipeline and distribution system may be steel, requiring expansion loops, or an asbestos cement material with rubber gasket joints that allow for expansion. Steel lines are usually placed above ground. Asbestos cement pipeline will generally be buried. Surface pipelines may be used where they do not restrict other uses of the land and when below-freezing temperatures are not common. Pipelines are buried for very practical reasons: burying reduces the heat loss from the system and enables less expensive materials (such as asbestos cement) to be used; it also hides the pipeline from vandals and damage from machinery, etc. Control valves should be located in concrete boxes allowing room for operation and maintenance.

Subsurface influences on conventional water supplies

Withdrawal of geothermal waters could have a variety of effects on conventional water supplies. The effects entirely depend on the geologic formation and the inter-relationship of the ground-water system.

To predict the effects, we need to evaluate the interaction of the geothermal reservoir with the shallow cold-water reservoir or perhaps the converse. If the interaction is of major proportion, the geothermal development may have detrimental effects on the domestic water reservoirs.

Benefits of reinjection into shallow cold-water aquifer would include: (1) reducing injection costs due to shallow well depth; (2) possibly reducing the costs of pipeline because injection might be feasible at the point of waste, (3) providing water to conventional water supplies, (4) reducing the potential for subsidence.

However, the water quality of the effluent to be injected may not meet those standards that require the injected fluid to be the same or of better quality than that of the receiving reservoir.

Subsidence and seismic activity

This activity is generally not likely to be a problem, but, under some conditions, long-term production could trigger subsidence and attended seismic activity. Subsidence becomes a potential problem when the reservoir is unconsolidated. In that case, the removal of fluid removes support for the overlying rocks and they will compact and thus cause subsidence. Where the reservoir is made up of competent rocks, the fluid does not provide support and its removal may not cause compaction. Injection of the used geothermal fluid back into the production reservoir usually minimizes any subsidence potential.

Seismic activity may be triggered by deep-seated subsidence caused by fluid removal. Such activity could be possible where an unconsolidated reservoir was being produced and the fluid was not being reinjected. However, seismic activity could also be produced if reinjection were practiced into dry-fracture/faulted zones. The injected water could lubricate the fault and promote premature slippage.

Protection against liability from supposed damage of surface structures or to shallower water wells should be planned for any major geothermal production scheme. An elevation and well monitoring system would be good protection. In the event a major field is being exploited, a monitoring plan might best be implemented by an independent monitoring organization, which might be a tax-supported entity.

WELL TESTING

Well testing is the general name for all techniques used to determine whether a well will produce usable fluids economically and for how long. Testing begins during drilling and usually continues as a monitoring program for the life of the well or resource. Testing involves measuring the following quantities: 1) temperature, 2) pressure, 3) flow rates of both mass and heat, and 4) fluid composition. The measurements are taken at the production well, at nearby wells, springs, and at injection wells. The basic procedures for testing and analysis have been adapted from petroleum-reservoir engineering and groundwater hydrology. Many of the techniques can be used without modification, but some techniques have led to significant new methods, such as fracture-type curve analysis, to meet the special conditions of geothermal reservoirs.

Equipment

Table 1 is a chart showing type of equipment vs. cost for each quantity we want to measure.

1. Temperature: Temperature-measuring devices range from mercury in glass thermometers through thermocouples with digital read-outs to Kuster temperature bombs. Maximum reading thermometers and thermistors can be attached to a hand-operated winch lowered into a well at minimal cost. Good thermometers cost about $50. Thermocouples with digital read-outs can be used only on the surface and cost about $300. They are rugged, reliable, and easy to use. Kuster tools require a wireline rig and cost around $8,000. They are used for temperature surveys of the entire hole and are justifiable only for fairly large products. They are effective but expensive. Temperatures should be taken downhole, at the well head, along the flowline and at the outflow end. All instruments should be calibrated before and after use. The type of winch or logging-cable drive depends on the needs. It may cost as little as a few hundred dollars for shallow-well capability or as much as tens of thousands for deep-well capability.

2. Pressure and water level (head) measurements: Pressure gauges vary in type and cost. Downhole gauges run high. The Hewlett-Packard quartz gauge is $15,000. Wellhead pressure can be monitored with a small gauge screwed onto a valve ($20) or a quartz gauge giving 6-figure accuracy (several thousand dollars). Gauges are easy to install along the flowline. Quartz gauges are most useful for multiwell interference tests where their extremely high sensitivity can give sufficient information to finish a test long before conventional gauges. Ordinary bourden-tube gauges are adequate for single-well tests. If the water level is below the surface, the most reliable method is the water-displacement technique using gas pressure in a small tube extending from the surface. Simple conductivity cells on the end of a line can serve for rough measurements, but they quickly foul from moisture, oil, etc.

A variety of methods can measure the flow rate of fluid. Downhole flow rates can be measured using spinners and thin film anemometers. Surface flow rates can be measured using a 55-gallon (208 l) drum and a stopwatch if the rates are low enough. Other methods include a home-built weir box and free discharge from a pipe with a manometer tube to measure differential pressure. The most precise, general-purpose method that can be used on wells of high pressure and high temperature is the orifice plate with differential-pressure meter recorder.

3. Composition. Numerous cheap, simple methods are available for determining composition. The pH can be measured with special paper for pennies or by a very rugged portable electric meter which costs about \$150, or the sample can be sent to a laboratory for about \$30-\$70/sample for determining the concentration of several elements as well as the pH. Total dissolved solids (TDS) can be determined with a small, rugged portable conductivity meter which costs about \$300 or sent to a laboratory. Hach kits and Draeger tubes are available at low cost for measuring specific chemicals. Non-condensable gas can be sampled in gas cylinders and analyzed in a laboratory, or it can be monitored on site using a gas chromatograph. This service is offered by mud loggers. If the expense is justifiable, portable gas chromatographs are available from \$1500-\$6000.

TABLE 1
Types and Costs of Measuring Equipment

Measured Quantity	Least Expensive				Most Expensive
	Increasing cost and complexity →				
Temperature	Maximum Reading thermometer \$20		Mercury in glass thermometer \$50		Digital thermometer \$300
Pressure	Simple mechanical gauges \$20		Pressure recorders \$900	Quartz gauges with recorders \$3000	Downhole quartz detectors \$15,000
Flow Rate	55 gal drum & stopwatch \$25	Weir box \$30	Free discharge manometer \$50	Spinners \$1000-\$2000	Differential pressure across orifice plates \$2000
Composition	pH paper \$5	Ionization meters \$300	Hach kits Draeger tubes \$600	Other wet chemical \$1000+	Gas chromatograph \$6000
Water Level	Electric conduction probe				Pressure-tube water displacement device

Tests and analysis methods

1. Temperature: During drilling, temperature should be taken at every opportunity. For example, the in and out drilling-fluid temperature should routinely be measured. Downhole temperature can be periodically measured using maximum-reading thermometers or continuous-recording platinum resistance thermometers downhole on a wireline between bit runs. Continuous logging of temperature in the borehole for a period after drilling usually can indicate the strata in the borehole of the resource. More elaborate and expensive measurements include injecting cold water into the well and running temperature surveys regularly for several hours to several days to determine the hot-water entry zones. During drilling, temperature can be monitored by other indirect techniques (for example, Crosby's method as described in the 1977 Stanford Geothermal Reservoir Engineering Conference Proceedings). Temperature surveys can reveal temperature reversals, cold water entries, and rate of thermal recovery.

2. Pressure and drawdown testing: Pressure testing is extensively discussed in various petroleum-engineering and groundwater-hydrology books because it is the best method for determining formation and well permeability, transmissivity (sometimes called transmissibility), well-bore damage, presence and extent of boundaries, faults, and fractures, interwell interference and long-term reservoir projections. Pressure gauges or water-level indicators are required and the well must be flowed and shut in according to a specific schedule. Analysis methods include Horner plots, semi-log plots, log-log type curves, and free water-surface analysis. Initial tests (up to 24 hours) are run while the rig is still on location because the tests might indicate that the hole should be deepened or cased or cemented. Once the rig has left the site, short- and long-term tests are run. Duration depends on many factors, but a short-term test is roughly 1-3 hours, while a long-term test can be 6 weeks to 6 months or longer. See the section below on long-term well performance predictions for further discussion.

3. Flow rate: Mass and heat flow rates can be monitored and plotted vs. time on semi-log paper to form pressure- or "head"-decline curves. These curves can be extrapolated to future production rates by routine mathematical techniques.

4. Composition: The concentrations of individual components can be determined and plotted vs. time. Changes in individual concentrations or in ratios of concentrations can indicate changes in the reservoir which might forecast temperature and flow-rate changes. There is also concern about presence of chemicals which would be deleterious to the process using the water.

5. Reinjection: Siting is the key problem in reinjection because one doesn't want to kill producing wells with cold-water breakthrough. Pressure-interference tests can be used to determine inter-well connections. Injection wells should be flowed, if possible, to clean up the well bore. Then they should be tested like the producing wells in order to determine how readily they will accept fluids.

Long-term well performance predictions - theory and analysis

Well and reservoir performance is governed by the fundamental laws of fluid flow in porous media. This law essentially reduces to the time-dependent diffusion equation:

$$\nabla 2h = \frac{S}{T}\frac{\partial h}{\partial t} \qquad (1)$$

This equation has such other classic analogies as heat diffusion (conduction), neutron diffusion in a nuclear reactor, and diffusion of a solute in a solvent. The solutions to the equation (1) have many forms, depending on the particular geometry and the boundary conditions for the problem at hand.

In the case of a well, the typical approach is to assume a two-dimensional problem in radial geometry; i.e., the well is assumed to be a point source in a plane. Equation (1) then becomes

$$\frac{\partial^2 h}{\partial r^2} + \frac{1}{r}\frac{\partial h}{\partial r} = \frac{S}{T}\frac{\partial h}{\partial t} \qquad (2)$$

where r is the radial distance from the well

- t is time
- h is the level of water in the formation (if the well is artesian, this "level" will become a pressure)
- S is the dimension less storage coefficient. It is the volume of water an aquifer releases or takes into storage per unit surface area per unit change in head. For confined aquifers, S is between 10^{-3} and 10^{-5}, or about 10^{-6} per unit of thickness. For confined aquifers, it is about 0.1 to 0.3.
- T is the transmissivity, the rate water is transmitted through the formation of unit width under a unit hydraulic gradient. Its units are gal/day-ft, ft^2/day of m^2/day (L^2T^{-1})
- h is the water level or pressure head in the well

The typical boundary condition is one of an infinite medium. Reflection or recharge boundaries can then be simulated by a reflected well on the other side of the boundary. Positive reflections indicate nontransmitting boundaries, negative reflections indicate recharge boundaries.

The solution for a well at constant flow rate Q is:

$$h = \frac{Q}{4\pi T}\int_u^\infty \left(\frac{e^{-u}}{u}\right) du \qquad u = \frac{r^2 S}{4\,T\,t} \qquad (3)$$

If the lower limit of integration, u, is less than 0.01, then an approximate solution is:

$$h = \frac{Q}{4\pi T}\left[-0.5772 - \log_e \frac{r^2 S}{4\,T\,t}\right] \qquad (4)$$

A plot of h vs. log T should give a straight line for times sufficient to make u < 0.01, with the slope of the line being $Q/(4\pi T)$. This is the common method of determining T. The drawdown to be expected for very long times can be obtained by continuing the slope on the semilog plot out to the desired time. Figure 9 shows a typical result of a well test. Good wells have value for T greater than 10,000 gal/day-ft (124 m^2/day).

WELL DEVELOPMENT AND STIMULATION

Well development and/or stimulation is an attempt to increase or regain productivity (injectivity) with minimal additional cost. Table 2 lists some of the more common techniques. The cost effectiveness of any technique depends on resource type and knowledge of the resource. Some mechanical techniques used improperly or in the wrong environment can increase or cause formation or borehole damage or can be costly with no benefit. Many techniques have been used in sequence or combination, increasing the cost-benefit analysis of utilizing any development/stimulation technique.

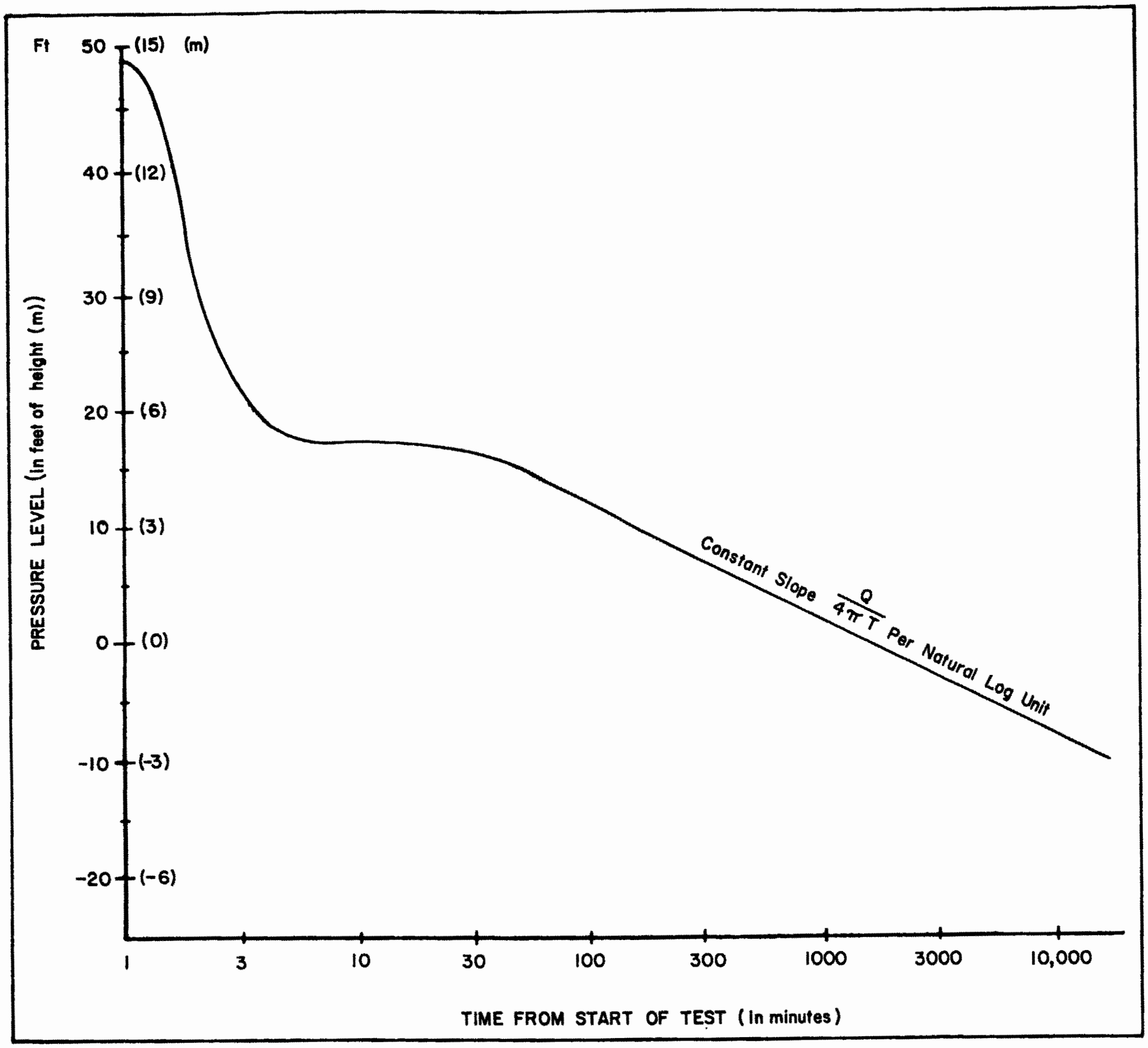


FIGURE 9. Typical geothermal well drawdown result. In this case, the well was initially "artesian." When pumped at constant rate, it lost its artesian head 14 hours after start of the test.

TABLE 2

WELL DEVELOPMENT AND STIMULATION TECHNIQUES

Type	Method	Description	Use	Requirements
Passive Mechanical	Bailer	Use sand line on drill rig to withdraw (add) water to well.	Clean well of cuttings or muds.	Can be accomplished with or without drill rig. No special equipment.
Passive Mechanical	Swabbing	Use a loose packer on drill pipe or sand line to swab/surge well.	Clean well of cuttings or muds. Develop gravel/natural pack.	Can be accomplished with or without drill rig. No special equipment.
Passive Mechanical	Rawhiding	Use a pump to produce (inject) fluid at rates higher than normal operation.	Clean well of cuttings or mud. Develop gravel/natural pack.	Pump and power supply. Dump (inject) large quantities of fluid.
Active Mechanical	Jetting	Use tubing with water ports at production face. Constant or pulsed flows.	Flush well of cuttings or mud.	Drill or pump rig to run tubing. Supply of fluid for jetting.
Active Mechanical	Explosives	Use explosives detonated at production (injection) face.	Promote or propagate secondary porosity. Correct drill damage or tight formation.	Experienced and licensed operator. Method to lower explosive.
Active Mechanical	Hydro-fracturing	Use high injection pressure to fracture rock. Can use proppant to hold fractures open.	Promote or propagate secondary porosity. Correct drill damage or tight formation.	Large quantities of fluid, pumper trucks, commercial services.
Active Mechanical	Sidetracking/ whipstocking	Use directional drilling to reach (additional) resource.	Increase effective borehole radius. Reach additional fracturing. Minimize drill damage.	Drill rig, directional drill services.
Active Chemical	Emulsifiers	Attack drill muds or formation clays.	Increase rate or effectiveness of cleaning well.	Chemicals, depository for spent chemicals and fluids
Active Chemical	Acid	Attack drill muds or particular minerals on formation.	Increase rate or effectiveness of cleaning well. Correct drill damage. Reach additional fractures.	Chemicals, depository for spent acids and fluids.

REFERENCES CITED

Bodvarsson, G. and Zais, E., 1977, A field example of free surface testing, _in_ Proceedings, Stanford Geothermal Reservoir Engineering Conference.

Craft & Hawkins, 1959, Applied petroleum reservoir engineering, Prentice Hall.

Crosby, G., 1977, _in_ Proceedings, Stanford Geothermal Reservoir Engineering Conference.

Earlougher, R.C., 1977, Advances in well test analysis, Society of Petroleum Engineers Monograph M-5.

Johnson Division, Universal Oil Products Co., 1972, Ground water and wells, 2nd printing.

Lohman, S.W., 1972, Ground water hydraulics, U.S. Geological Survey Prof. Paper 708.

Matthews, C.S. and Russell, D.G., 1967, Pressure buildup and flow tests in wells, Society of Petroleum Engineers Monograph M-1.

Watson, J.C., 1978, Sampling and analysis methods for geothermal fluids and gases, Battelle Memorial Institute, PNL-MA-J72.

Zais, E., 1977, Decline curve analysis in geothermal reservoirs, _in_ Proceedings, Stanford Geothermal Reservoir Engineering Conference.