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DESIGN CONSIDERATIONS FOR A STEAM-INJECTION PILOT WITH IN-SITU FOAMING

Topical Report

Work Performed for the Department of Energy
Under Contract No. DE-AC03-76ET12056

Date Published—August 1982

Stanford University Petroleum Research Institute
Stanford, California

U. S. DEPARTMENT OF ENERGY

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DESIGN CONSIDERATIONS FOR A STEAM-INJECTION PILOT WITH IN-SITU FOAMING

Topical Report

SUPRI TR-21

By

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UNITED STATES DEPARTMENT OF ENERGY

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ABSTRACT

This report reviews the necessary aspects of the planning, operation, evaluation, environmental impact and cost to implement a field pilot of steam injection with in-situ foaming. The Stanford University Petroleum Research Institute (SUPRI) is planning to implement such a pilot in Kern County, California. The cost of the pilot will be shared by the U.S. Department of Energy and an oil company. Some important aspects of drilling and completion programs and their specifications, permits from regulatory bodies, and downhole tools to improve steam stimulation are discussed. The essential surface facilities which include water treatment plant, steam generator, demulsifier and dehydrator are considered. The necessary laboratory research in support of the pilot has been recommended.

The formation evaluation and reservoir engineering effort for the pilot has been divided into three phases: reservoir definition, reservoir monitoring and post-pilot study. Appropriate techniques applicable to each phase of the test have been discussed. The environmental impact regulations as related to the steam injection process ahve been considered. In particular, the environmental problems associated with the burning of crude oil and desulfurization of flue gas have been discussed. Other environmental considerations such as solid and liquid waste disposal, health and safety are also discussed.

An estimate of the cost of this field test is presented. The cost figures reflect conditions for the Kern County, California field. Costs of several surfactants have been utilizes. Estimates for both the purchase and lease of surface equipment have been included. Three scenarii (for pilots with high, medium, and low investment potentials, respectively) are presented. Since this report was prepared, a specific site for the supri pilot has been chosen. Appendices G and H present the details on this site.

1. INTRODUCTION

Steam drive is the most common enhanced oil recovery process currently in use. This process is energy-intensive because it requires the use of a significant fraction (25 to 40 percent) of the energy in the produced petroleum for the generation of steam. The cost of the steam generator, together with that of fuel is about 55 percent of the total operating cost per barrel of oil produced (see Appendix A[19]). A large part of the steam injected in most steam drives is wasted because of gravity override and channeling. Thus, the heat content of steam is not fully utilized. The heating value of one barrel of crude oil is equal to the heat content of 13 to 14 barrels of water converted to steam, allowing for an overall thermal efficiency in generation and distribution of about 75%. Thus, the steam/oil ratio will have to be less than 13 for the project to be considered practical; how much less depends on the operating expense and the crude oil price. The economic limit is about 8 barrels of water converted to steam per barrel of oil for most existing operations in the United States.

1.1 IMPORTANT PARAMETERS AFFECTING STEAM DRIVE

Some of the important parameters governing the behavior and efficiency of steam drive follow: 1) A high saturation of oil-in-place is required because of the intensive use of energy in the generation of steam; 2) The greater the thickness of the reservoir, the greater is the thermal efficiency because the amount of heat lost to the cap and base rocks varies inversely with reservoir thickness; 3) For a given injection rate, the time to breakthrough increases with the formation thickness, and for a given thickness, the time to breakthrough increases as injection rate decreases; 4) The higher the injection rate, the lower the heat losses because heat losses increase with time; 5) The higher the injection rate for any given pattern size, the shorter the time of operation.

1.2 LIMITATIONS OF STEAM DRIVE

Steam is injected into the reservoir to reduce the viscosity of the oil and to make the oil more mobile. The low density of steam compared to reservoir fluids causes gravity override, and consequently, early steam breakthrough in production wells and a rapidly increasing steam/oil ratio. Also, because of the high viscosity of crude oils compared to steam, the mobility ratio in a steam drive is very high. This causes poor sweep and poor vertical conformance. Steam tends to channel through high permeability layers in a reservoir causing an early increase in the steam/oil ratio. The phenomena of gravity override and channeling sharply reduce the oil recovery potentially achievable by steam drive.

To overcome the technical and economic limitations of steam, additives to steam are sought. Additives are needed that can plug the steam-filled zones depleted of oil, so that the injected steam is diverted into those parts of the reservoir which are still saturated with oil.

1.3 IN-SITU FOAMING WITH STEAM

The most promising method of correcting gravity override is to selectively block the flow of steam into the structurally higher parts of the reservoir. Similarly, reduction of steam channeling can be achieved by selectively reducing the permeability of high-permeability channels. The use of in-situ foaming with steam is a potential means for accomplishing these objectives.

A foam provides good displacement efficiency due to the high apparent viscosity of foam which improves the mobility ratio of the displacement process. The need for blocking the entry of steam into depleted intervals using foams, and diverting it into intervals that still have a high oil saturation is consistent with the mechanism offered for the displacement of oil by steam. A foam has to fulfill certain requirements to be effectively used as an additive to steam drive. It must be stable at relatively high temperatures. A foam must be able to reduce permeability, penetrate deep into the desaturated zones, and the foaming ability should persist for an extended period of time at reservoir conditions. It is important to note that the blocking of the desaturated zone must occur over a great distance in the formation otherwise cross-flow within the reservoir whould negate any blocking that occurs only around the wellbore. THe cost of foam should be such that its use can be economical. One of the research projects at the Stanford University Petroleum Research Institute (SUPRI) is aimed at improving the efficiency of steam drive by using in-situ foaming with steam injection. Laboratory results at SUPRI indicate that the above-mentioned objective is technically feasible and further research is in progress. The next step is to coordinate the laboratory research with a pilot test of the process in the field.

The main purpose of this study was to specify the design considerations, both engineering and economic, for a field pilot of in-situ foaming with steam injection. The proposed field test will involve at least two five-spots in the same reservoir, one for steam injection and the other for the injection of alternate slugs of foamer solution and steam. This will allow a comparison of the performances with and without foam injection. Each five-spot (typically 2.5 acres) will have a central injector, four producers, and a cased observation hole in between the injector and one of the producers. The surfactants considered for in-situ foaming are Suntech IV, Thermophoam BWD and Corco-180. In estimating costs, it is assumed that the test period will be two years and the test site will be in Southern California. The following sections review the engineering and economic aspects of the design and operation of this pilot.

2. DRILLING, COMPLETION AND DOWNHOLE TOOLS FOR STEAM STIMULATION WELLS

Enhanced oil recovery by steam injection creates several well problems, both before and after injection. THe difficulties frequency associated with high temperature injection are:

1) Casing failure; Fig. 2.1 shows how the mechanism of thermal stresses leads to casing breakdown;
2) Cement bond breakdown;
3) Sloughing of formations in uncemented upper segments of the hole; and
4) Corrosion due to the presence of H_2S, CO_2 and NO_x in steam.

All the anticipated field conditions should be considered, and then a safety factor should be applied which will adequately protect against all eventualities. However, the economics involved should be balanced against the safety factors.

Some specific problems encountered in most thermal recovery projects are:

1) Failure of conventional cementing composition which exhibit strength retrogression at temperatures above 240°F;
2) Failure of cement bond to pipe and formation because of poor placement techniques, or excessive formation washout;
3) Failure of casing due to accelerated corrosion above the cement;
4) Parting of casing cemented only at the bottom because incompetent formations seized the upper portion of the string; and
5) Parting of low-grade casing in spite of satisfactory cementing materials and practices.

Casing failure mechanisms under high temperature are summarized in Appendix B and the basic factors to be considered in the design of the casing are summarized in Appendix C. The design of a steam stimulation well requires all the above special considerations of thermal effects. A well failure disrupts the operation and adds to the expense.

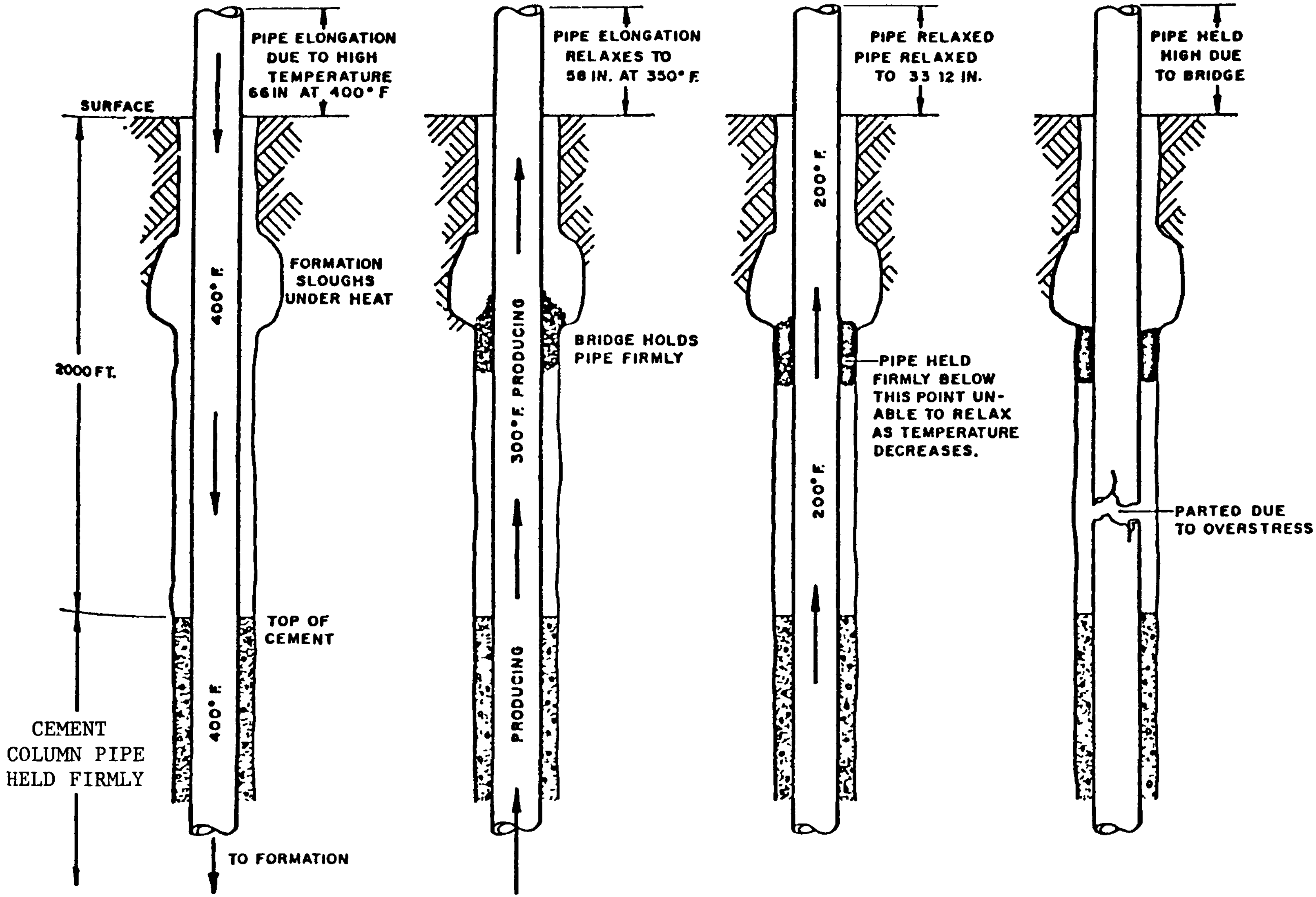

Fig. 2.1: CASING FAILURES UNDER THERMAL STRESS (Ref. 4)

2.1 SOME CASING DESIGN ASPECTS

The thermal stresses in a firmly-cemented casing induce compression when heated and tension when cooled as shown in Fig. 2.2. The well design presently used relies on maximum free-casing movement to minimize high temperature-induced stresses. The necesssity for bonding a well casing in place is even greater in a well that will be thermally stimulated. The casing must be bonded securely, in at least one section--typically a middle one--to segregate the fluids that might be subjected to inter-zonal flow. This single bonded section should be at the top of the pay zone, which is also at the shoe of casing. The design has two distinct parts: the "stress section" and the "slip section," as shown in Fig. 2.3.

Table 2.1 gives the relationship between the length of pipe string in feet and its elongation in inches, due to changes in temperature. This indicates how much slip will take place in the "slip section." It is also important to note that the wellhead will rise up due to the elongation of the tubing and casing. Casing undergoes many variations in its axial load from the beginning of casing placement in the well to the completion and injection of steam. Figure 2.4 shows how the tension in the air-hung pipe string is reduced due to the buoyancy in drilling mud. When this same pipe string is cemented, most of the tension is replaced by compression and only a part of the upper portion remains under tension. Eventually, when this pipe string is exposed to high temperature, compression increases three-fold under thermal forces. A casing material should be selected such that it can withstand the anticipated variations in the axial load.

2.2 SOME ASPECTS OF CASING MATERIALS

It is important that the temperature effects on the yield strength, ultimate tensile strength and modulus of elasticity of the casing material be considered prior to preparing specifications on the casing. Thomas[8] has collected various high-temperature casing data from a group of manufacturers and demonstrated similarity in changes of physical properties of casing at elevated temperatures.

Greer et al.[1] used the data collected by Thomas[8] and prepared the following correlations, using four different grades of API tubular

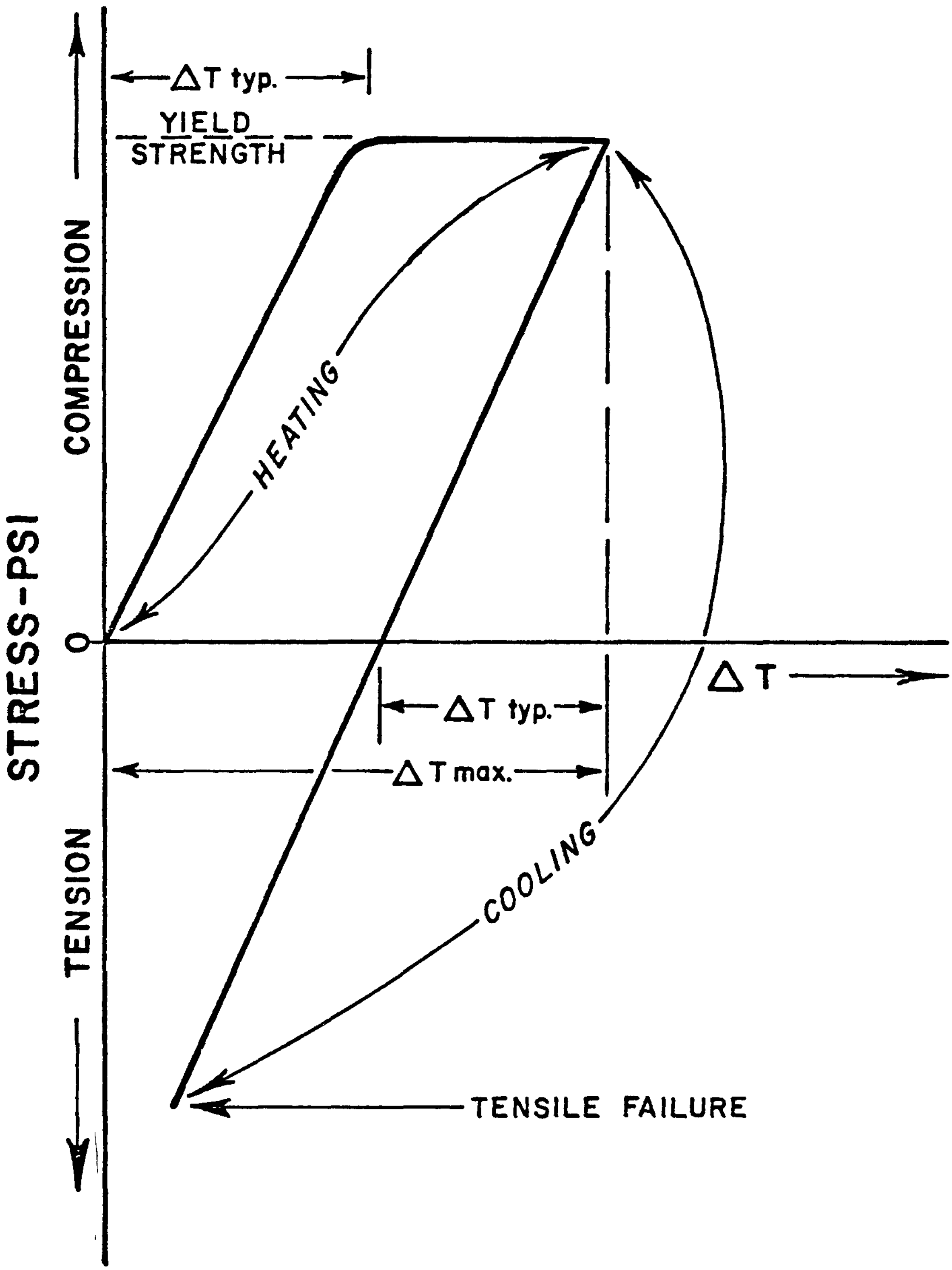

Fig. 2.2: THERMAL STRESS HISTORY OF CASING HEATING AND COOLING (Ref. 87)

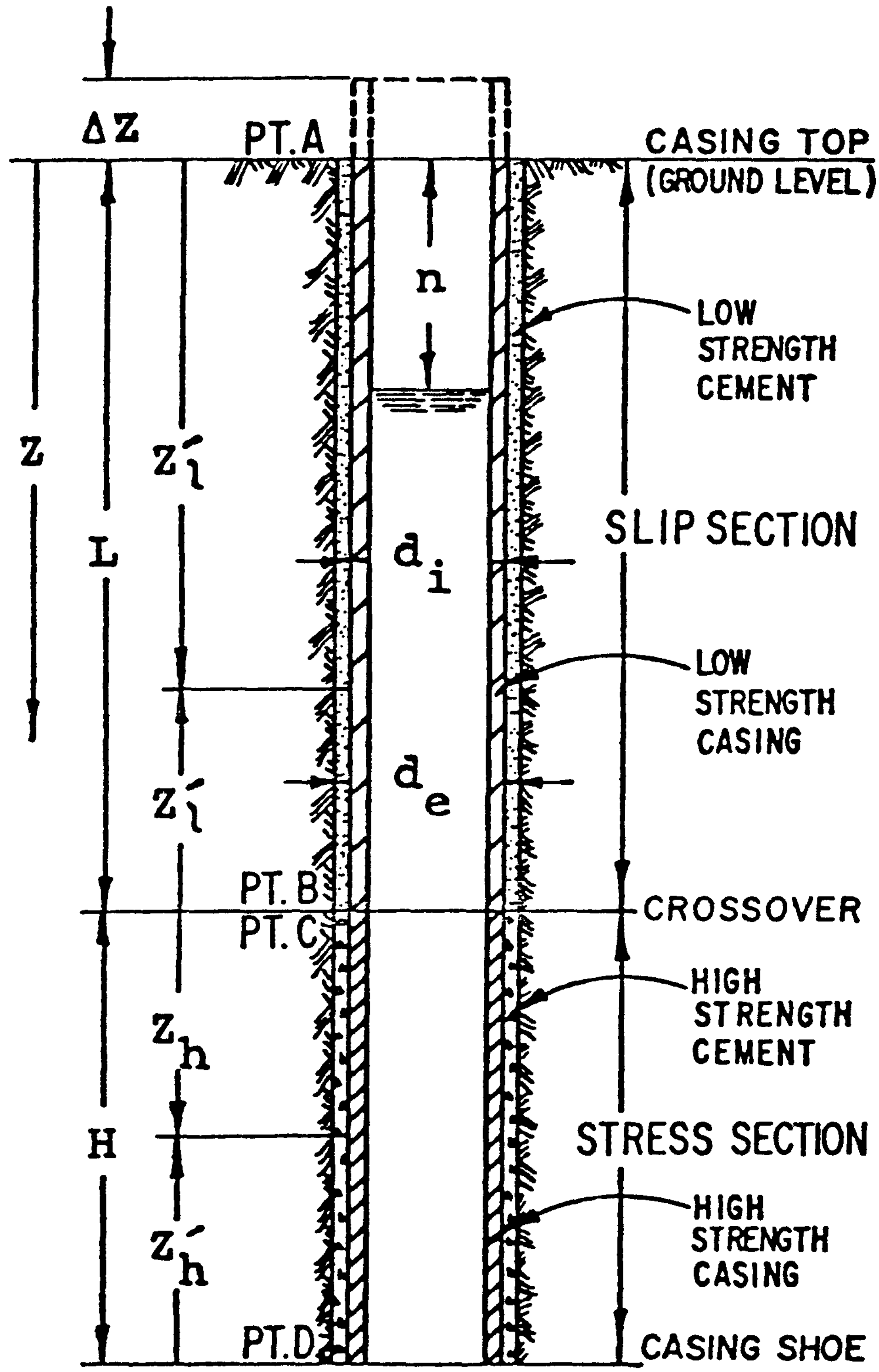

Fig. 2.3: DIAGRAMMATIC REPRESENTATION OF PROTOTYPE WELL COMPLETION (Ref. 4)

TABLE 2.1

ELONGATION OF TUBING OR CASING DUE TO TEMPERATURE CHANGE (Ref. 4)

Length of Pipe String, Feet	50^{o}	100^{o}	150^{o}	200^{o}	250^{o}	300^{o}	350^{o}	400^{o}	450^{o}	500^{o}
	INCHES ELONGATION									
500	2.07	4.14	6.21	8.28	10.35	12.42	14.49	16.56	18.63	20.70
1,000	4.14	8.28	12.42	15.56	20.70	24.84	28.98	33.12	37.26	41.40
1,500	6.21	12.24	18.63	24.84	31.05	37.26	43.47	49.08	55.89	62.10
2,000	8.28	16.56	24.84	33.12	41.40	49.68	57.96	66.24	74.52	82.80
2,500	10.35	20.70	31.05	41.40	51.75	62.10	72.45	82.80	93.15	103.50
3,000	12.42	24.84	43.47	57.96	72.45	86.94	101.43	115.92	130.41	144.90
4,000	16.56	33.12	49.68	66.24	82.80	99.36	115.92	132.48	159.04	165.60

* Temperature in ^{o}F

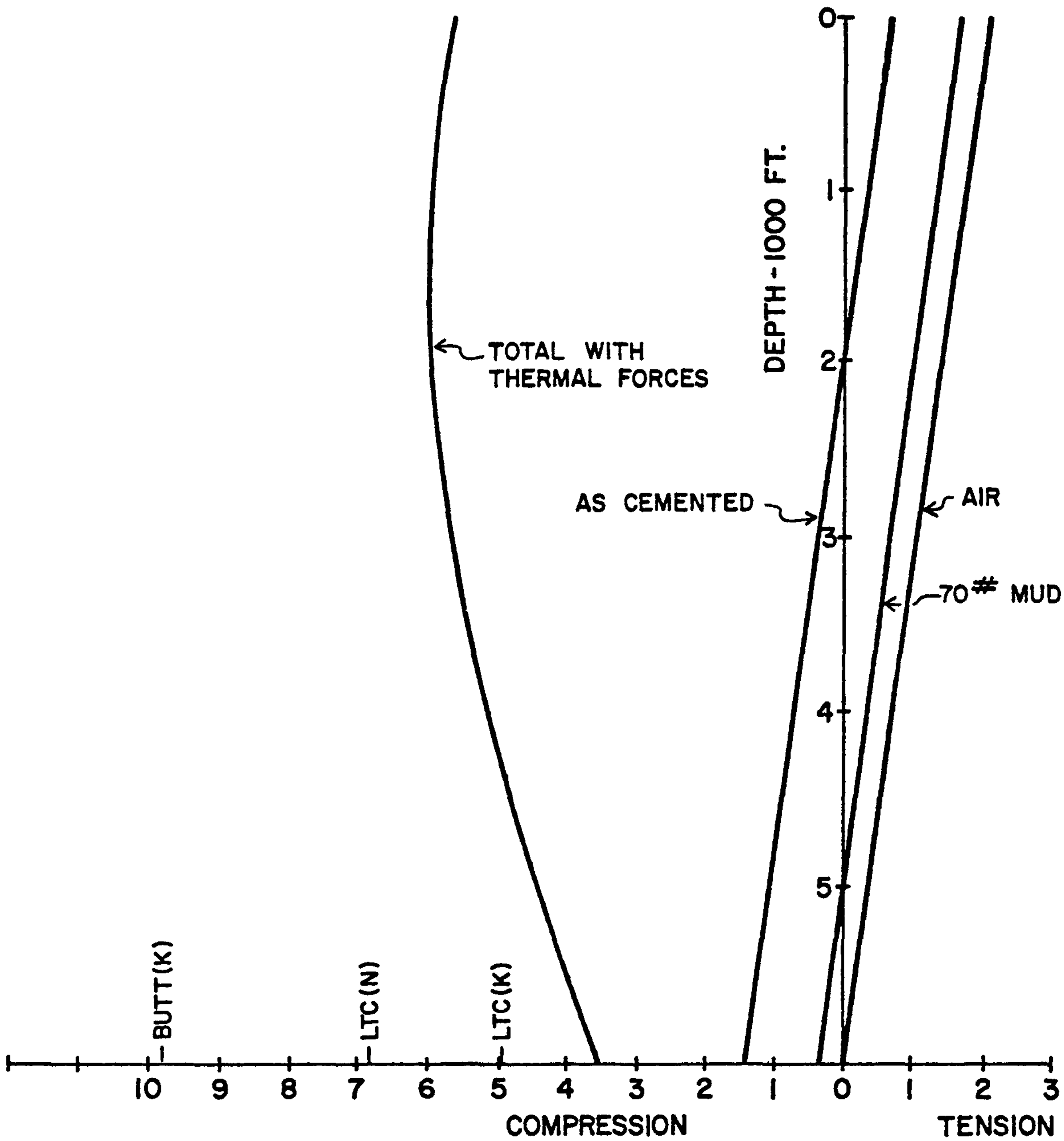

Fig. 2.4: AXIAL LOAD PROFILE FOR 8 5/8 36# CASING (Ref. 87)

steel (P-110, P-105, J-55 and N-80):

1) Modulus of elasticity vs temperature (Fig. 2.5);
2) Variation in yield strength vs temperature (Fig. 2.6); and
3) Variation in ultimate tensile strength vs temperature (Fig. 2.7).

From the above data, API-grade N-80 steel would be the most suitable for use in steam injection wells. After the selection of casing material, drilling and completion of the well would be the next step to be considered.

2.3 DRILLING PROGRAM

The majority of the known heavy oil reserves in California are in Kern County where the reservoir depth averages between 700-1500 ft. It is assumed that the pilot will be located in Kern County.

Ikoku et al.[26] have shown that foam drilling offers the following advantages: 1) wet cuttings can be removed from the hole with less pressure; 2) sloughing is reduced because of pressure stabilization; 3) penetration rate and bit life are improved because the pressure is stabilized at a lower level than if wet cuttings were allowed to build up.

A typical drilling program in the Kern County area consists of drilling a 12 1/4-in. hole to approximately 250 ft and the nippling up an 8-in. or 6 7/8-in., 2,000 psi blow-out preventor (BOP) stack (Fig. 2.8). Following this, a 9 7/8-in. hole may be drilled to the top of the productive zone using low-solids gel mud or pre-formed foam. At this point, a suite of logs may be run. Following the open-hole logging, 7-in. N-80 buttress casing may be run and cemented using special cements for thermal operation.

2.4 CONSIDERATION OF CEMENT PROPERTIES

In a steam injection well, many problems in cement bonding are encountered due to sudden variations in temperature. Temperature-stable cements must be carefully selected for the steam injection wells. Cain, et al.[2] published cement compositions which are temperature stable. Where high temperatures are anticipated, the following compositions are appropriate:

1) API Class A or G with 30 to 60 percent silica flour;
2) Pozzolan cements blended by combining 1 cu-ft of API Class A or G cement with 1 to 2 cu-ft of Pozzolan, 30 to 60 percent

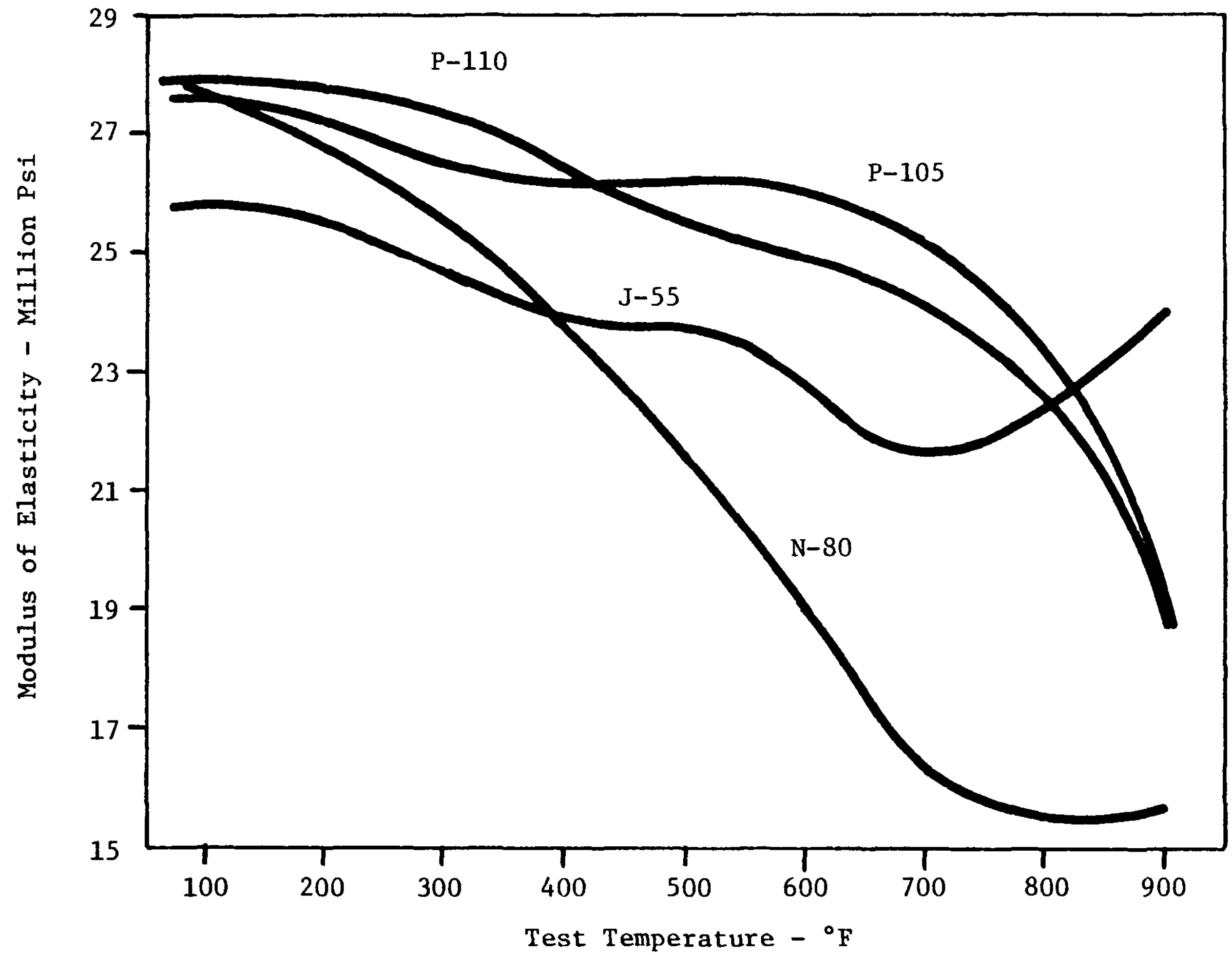

Fig. 2.5: MODULUS OF ELASTICITY VS TEST TEMPERATURE (Ref. 1)

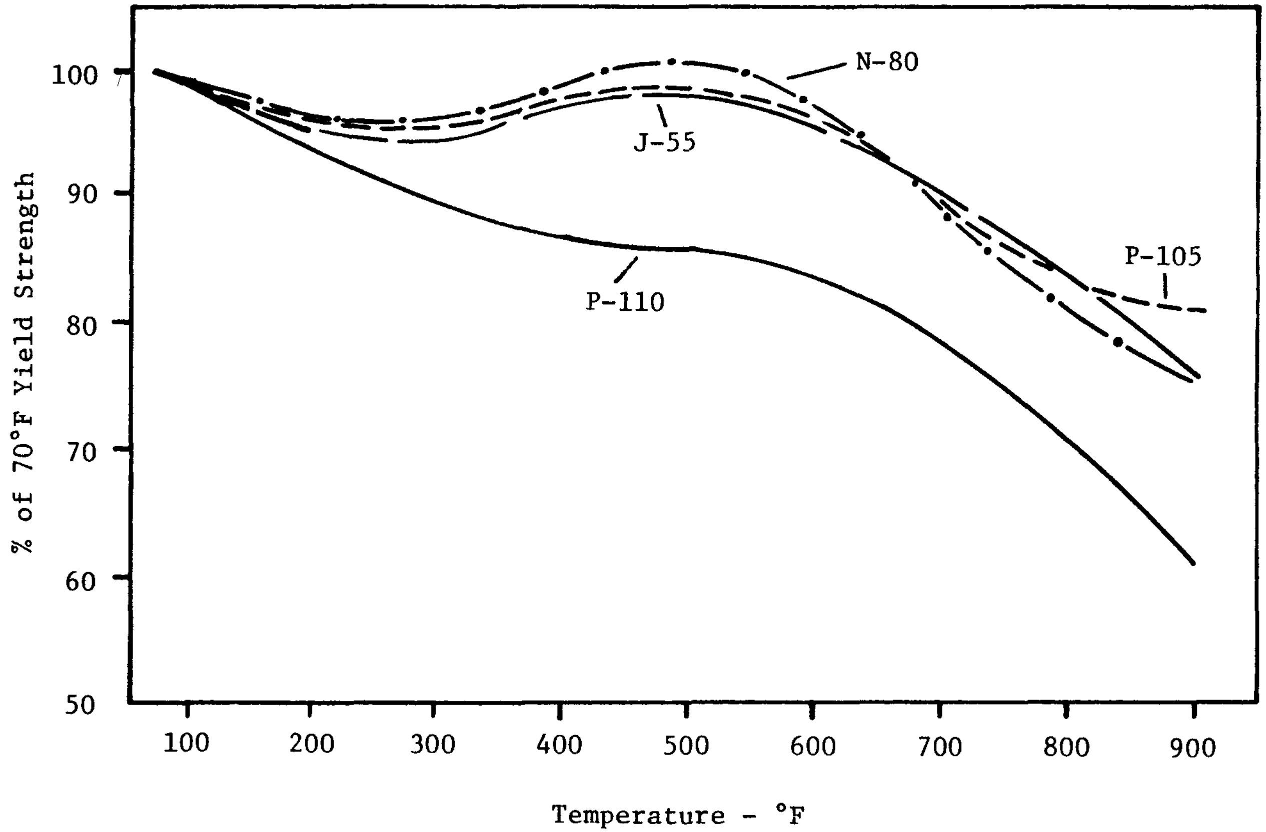

Fig. 2.6: VARIATION IN YIELD STRENGTH VS TEMPERATURE (Ref. 1)

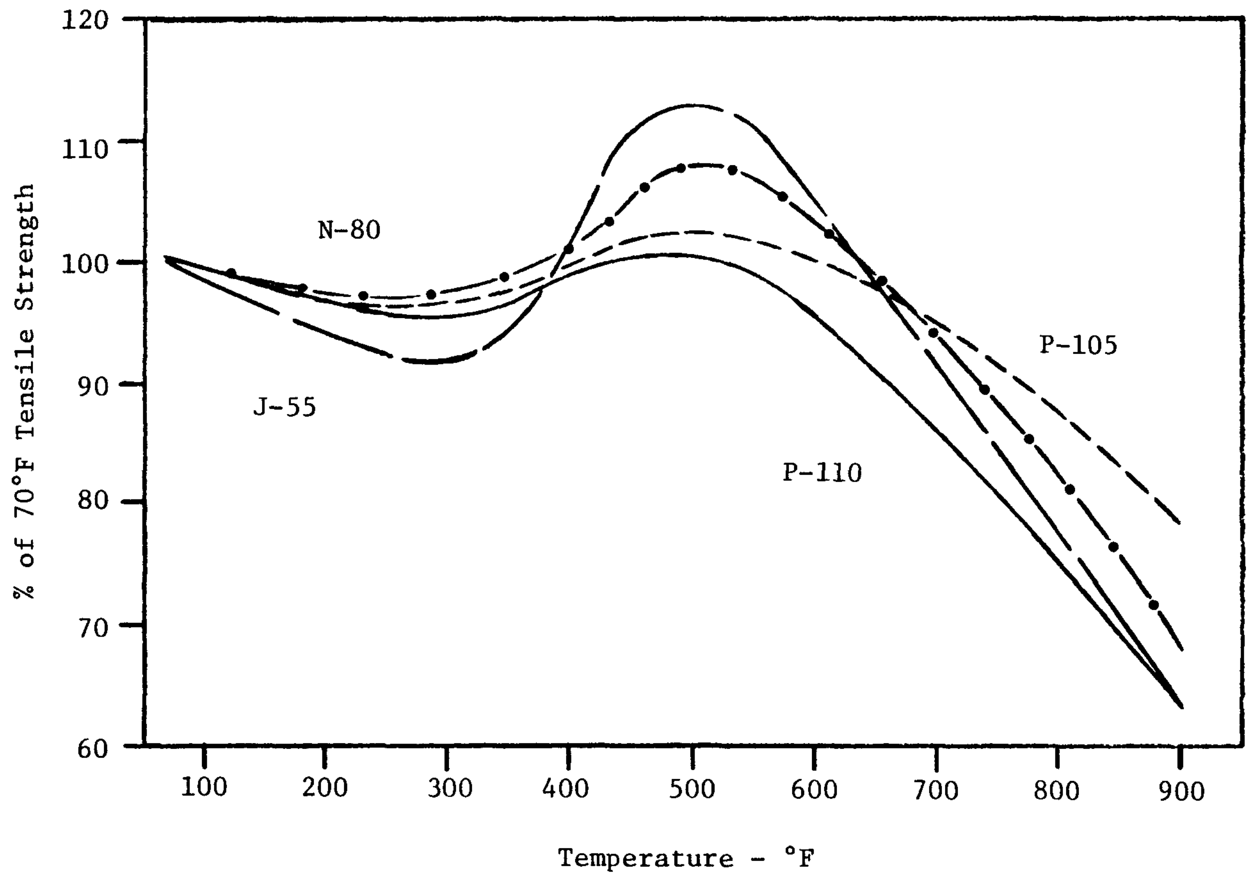

Fig. 2.7: VARIATION IN ULTIMATE TENSILE STRENGTH VS TEMPERATURE (Ref. 1)

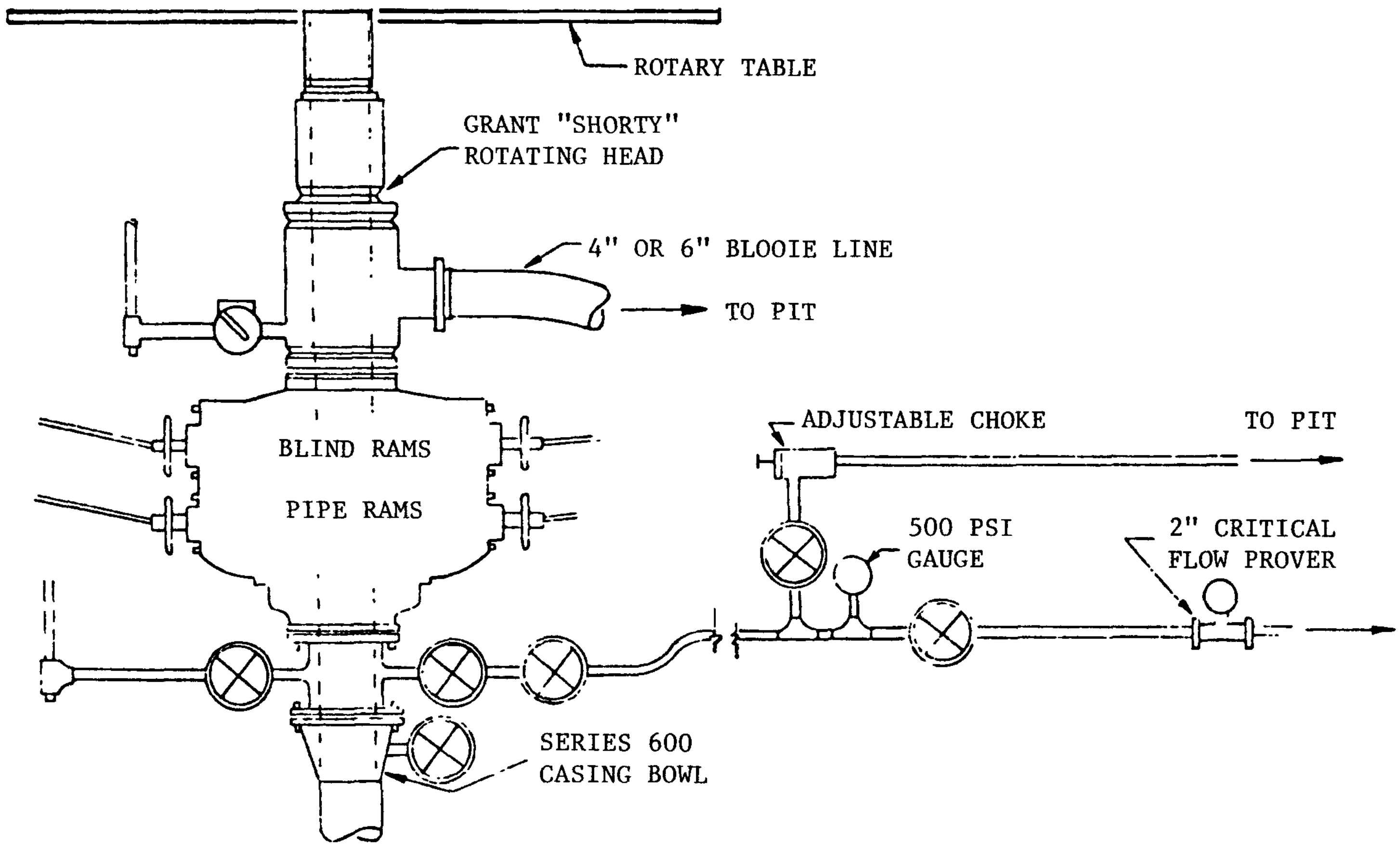

Fig. 2.8: BLOWOUT PREVENTER HOOK-UP (Ref. 44)

silica flour and 0 to 2 percent bentonite;

3) API A or G with 1, 2 or 3 cu-ft of expanded perlite, 30 to 40 percent silica flour and 0 to 2 percent bentonite; or

4) Calcium aluminate cement, a refractory composition used with or without silica flour.

Greer, et al.[1] formulated the most suitable compositions for stress and slip section cements. Compressive strengths at various curing times and temperatures are shown in Tables 2.2 and 2.3. Appendix E summarizes a typical cementing procedure. Using the cement composition of Greer, et al.,[1] the wells man be completed with the typical specifications discussed in the subsequent sections.

2.5 COMPLETIONS

Programs calling for 8 5/8-in. liners, or 7-in. casing with 5.5-in. liners are standard practice, but there can be set rules covering different fields.

For the pilot, a program of tight liner completions should be adopted using 24-lb, N-80 7-in. surface pipe and 24-lb, N-80 5.5-in. liner. The liner also permits the use of 2 7/8-in. tubing with small diameter couplings such as sealock and larger 2.25 by 2.25-in. bottom-hole pumps, and still provides room to wash over a stuck string. The liners should be conventional 60-mesh slots, 16 rows x 1.5", providing a sufficient area for oil entry to the well bore.

2.6 GRAVEL PACKING

The Kern River reservoir consists of an alternating sequence of unconsolidated sands with considerable interbedded silts and clay. This causes a severe sand problem. Gravel packing helps solve this problem and also offers the following advantages:

1) Better drainage area to the well bore by virtue of the gravel surrounding the liner;
2) Wider slots permitting more oil to enter the well as the zone cools off and the oil becomes more viscous;
3) Possible greater ease in pulling liners should this become necessary; and
4) Possible greater freedom for the liner to exand and contract with temperature changes with less risk of parting the liner.

TABLE 2.2

STRESS SECTION CEMENT (Ref. 1)

COMPOSITION

Class G cement: 94 lb

Silica flour (40 percent): 37.6 lb

Slurry weight: 116 lb/cu ft

STRENGTH

Curing Time	Compressive Strength (psi) at Curing Temperature			
	100	400	460	440/725*
8 hrs	300	-	-	-
12 hrs	790	-	-	-
16 hrs	1,045	-	-	-
24 days	1,490	4,890	3,890	7,330
3 days	-	-	6,340	11,025
7 days	-	6,500	-	10,010
27 days	-	-	7,875	-

* Cured designatd time at 440°F, followed by 3 days at 725°F.

Modulus of elasticity E_e: 0.8×10^6 psi

Coefficient of linear expansion λ_e: 6×10^{-6}, $°F^{-1}$

Thermal conductivity (at 325°F):
0.833 Btu/hr/sq ft/°F/ft

Thermal conductivity (at 548°F):
0.533 Btu/hr/sq ft/°F/ft

Permeability: 0.036 md

TABLE 2.3

SLIP SECTION CEMENT (Ref. 1)

COMPOSITION

Class G. Cement: 94 lb

Silica Flour: 80 lb

Gel: 3.48 lb

Perlite: 96 lb

Slurry Weight (at 0 to 1,500 psi): 65 to 82.3 lb/cu ft

STRENGTH

Curing Conditions			Compressive	Shear	Shear-Bond
Time (days)	Temperature (°F)	Pressure (psi)	Strength (psi)	Strength (psi)	Strength (psi)
1	100	1,500	16	2	-
1	110	1,500	29	8	3
1	400	3,000	391	101	47
3	400	3,000	330	81	42
4	110	1,600	132	-	-
7	470	1,600	488	-	-

Modulus of elasticity E_e (4 days at 100°F): 0.0325×10^6 psi

Modulus of elasticity E_e (7 days at 470°F): 0.0407×10^6 psi

Coefficient of linear expansion, λ_e

Thermal conductivity (approximate): 0.4 Btu/hr/sq at/°F/ft

Permeability (4 days at 110°F): 0.68 md

Permeability (7 days at 470°F): 0.24 md

2.7 DOWNHOLE TOOLS

After successful drilling and completion of the wells, the next important step is to install a set of downhole equipment to minimize thermal stresses on casing and improve steam stimulation efficiency. It is necessary to understand the heat losses in a well-bore during steam injection. Ramey[31] has explained the phenomenon of wellbore heat transmission; Sather[32] and Willhite[33] calculated the heat losses during flow of steam down the wellbore. Most of the problems in thermal oil recovery are related to casing failures as reported in Refs. 34-39. Tools that avoid potential casing failures and improve steam stimulation operation as reported by Hutchison[29] include:

1) Cup packer with back-up rings to avoid entry of steam in previously treated zones.
2) Concentric steam deflectors which distribute steam from tubing to one or more intervals without undesirable erosion effects.
3) A high temperature safety joint that offers controlled-tension failure with unlimited torque and compressive strength, for easier steam tool recovery.
4) Special isolation packers that can block entry of undesirable steam breakthrough into a producing well.
5) Multiple zone steam stimulation.
6) A low heat conductivity, frangible centralizer which cuts loss of steam energy between tubing and casing and allows string washover and recovery.

A brief description of the above-mentioned tools follows.

2.7.1 Cup Packer with Back-up Rings

Steam tends to enter previously-treated zones, which can be detected by temperature and radioactive surveys. Steam stimultion becomes uneconomic when steam enters previously-treated zones repeatedly. Use of packer cups avoids this and achieves vertical segregation. Figure 2.9 shows the packer cup with brangible back-up ring. The cup rubber is ethylene propylene for steam service and Neoprene or Hycar for oil service. One theory of how a packer cup provides a vertical seal is that there is sufficient flow initially past the cup to carry sand, and it is sand build-up that forms the seal. If this theory is true, the ability to wash over the packer cup is an important consideration.

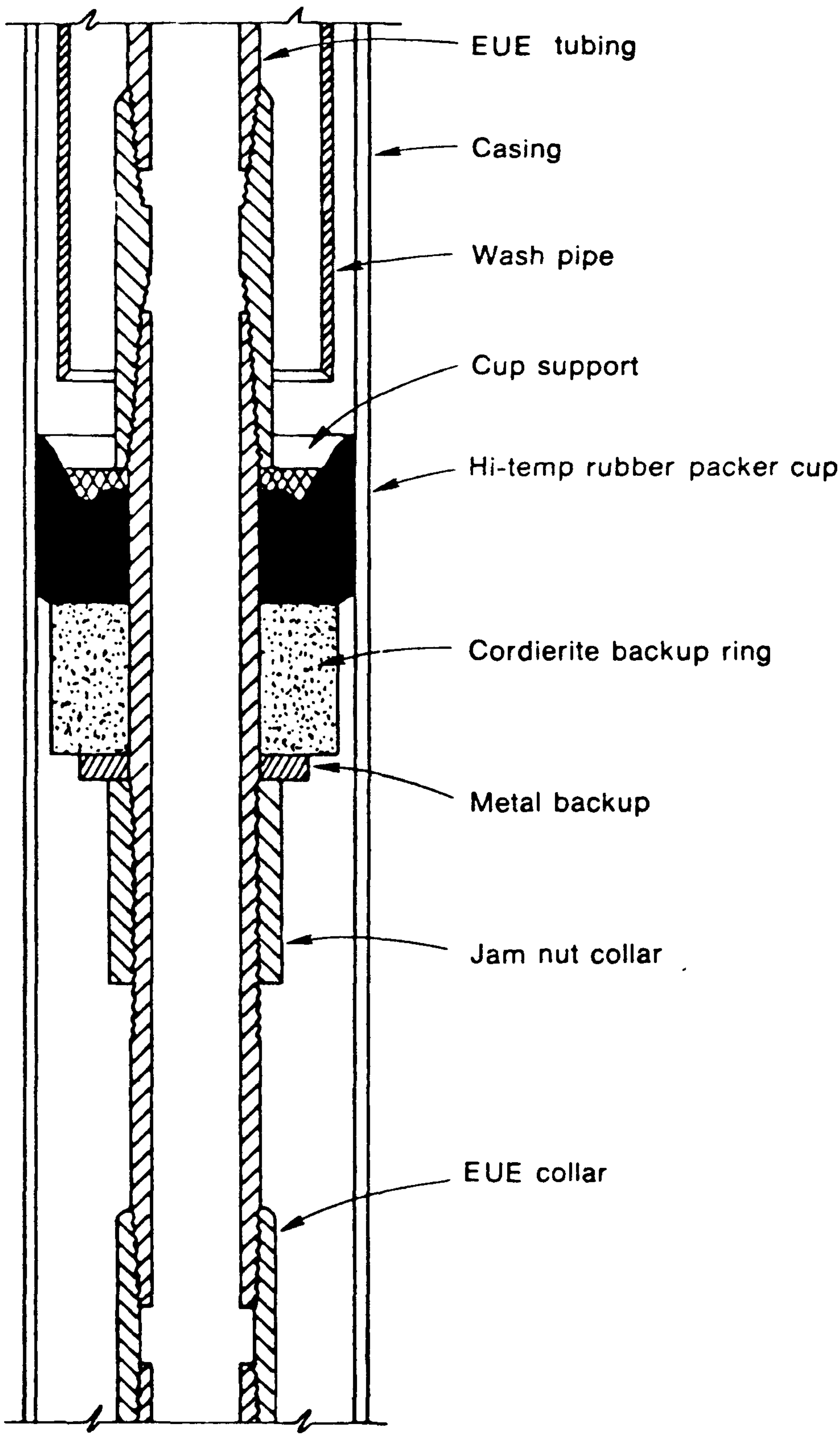

Fig. 2.9: CUP PACKER DETAIL ILLUSTRATES USE OF SPECIAL FRANGIBLE BACKUP RING THAT ALLOWS PACKER TO BE EASILY FREED BY WASHOVER PIPE. ALL METAL SUPPORT RINGS HAVE OD'S SMALL THAN WASH STRING ID (Ref. 43).

2.7.2 Steam Deflectors

Steam by itself would not erode steel at any velocity. However, a hole can be eroded in a liner with as little as nine pounds of sand exiting from a jet stub at high velocity. The erosion rate increases as tubing-casing stand-off distance decreases. Figure 2.10 shows details of two types of concentric steam deflectors. When these deflectors are centralized in the wellbore, steam can exit uniformly into the tubing-casing annulus where velocity is reduced in the shortest possible distance.

2.7.3 High-Temperature Tension Safety Joint

It is highly desirable to have a convenient, low-cost way to separate the tubing string at a predetermined point, if the thermal packer or tubing becomes stuck. The upper portion of the string then can be pulled and a proper fishing tool assembly run to recover the packers. Figure 2.11 shows in detail a high temperature tension safety joint. This tool is strong in compression but weak in tension. Varying the size and/or number of shear pins allows the operator to predetermine the tension force required for the tool to "come apart." Thus, cost and time delays involved with tubing cutting are avoided.

2.7.4 Controlling Profiles in Producing Wells

Steam tends to rise to the top of the zone due to gravity override, and consequently, leads to early breakthrough in production wells. Later, the steam carries sand, and as the velocity increases, this carried sand usually erodes a hole in the tubing. The packers for isolating a steam breakthrough interval are shown in Fig. 2.12. The cup paker isolation assembly allows well vapor to bypass the packer. The cups can be separated by any distance and they can be washed over if they become stuck. The single rubber packer isolation assembly also allows well vapors to bypass the packer. The rubber on this model is molded onto 4-in. pipe and trimmed to provide a snug fit in the casing or liner in which it is run.

2.7.5 Multiple-Zone Steam Equipment

Figure 2.13 shows the schematic of multiple-zone steam stimulation equipment used to obtain the minimum heat loss, positive displacement,

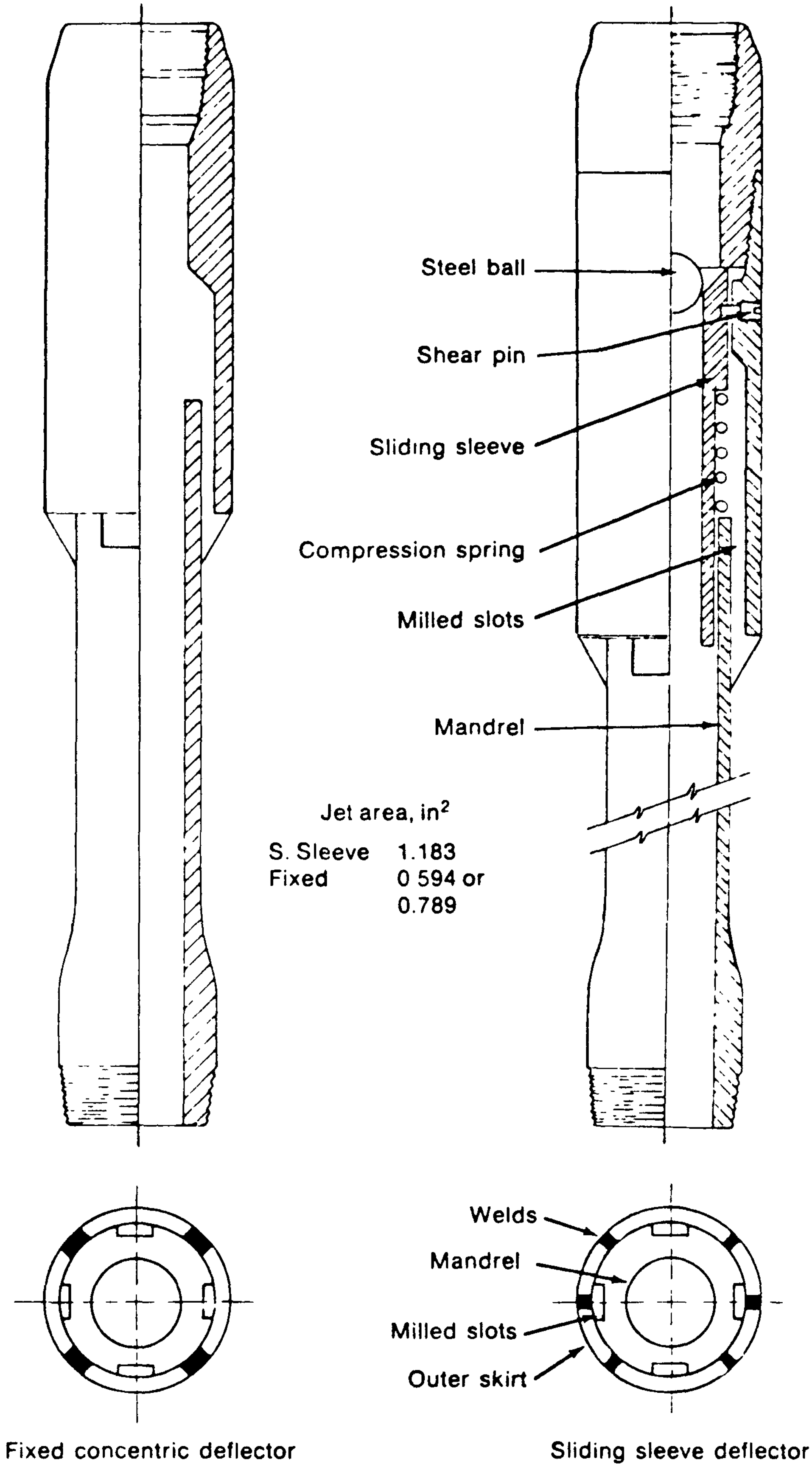

Fig. 2.10: TWO TYPES OF CONCENTRIC STEAM DEFLECTORS. FIXED TYPE (LEFT) ALLOWS PORTION OF TOTAL STEAM FLOW TO EXIT TUBING STRING IN PROPORTION TO SLOT SIZES WITHOUT SAND EROSION EFFECTS. SLEEVE TYPE (RIGHT) IS CLOSED UNTIL OPENED BY DROPPING BALL, THEN ALL FLOW MUST PASS THROUGH SLOTS (Ref. 43).

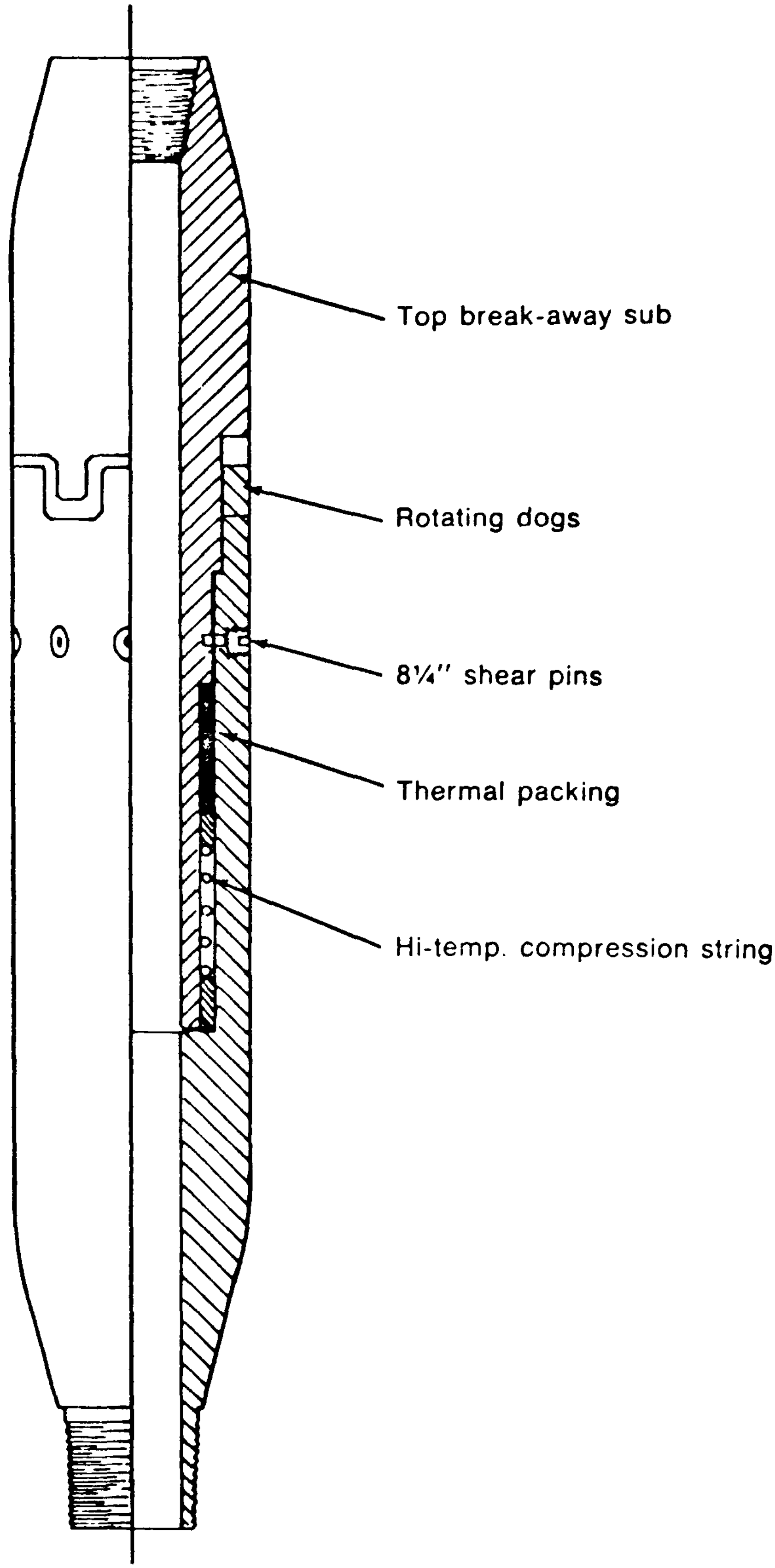

Fig. 2.11: HIGH TEMPERATURE SAFETY JOINT TOLERATES COMPRESSION AND TORSIONAL LOADS BUT PARTS WITH PRE-DETERMINED TENSION SO STEAM TOOLS CAN BE WASHED OVER (Ref. 43)

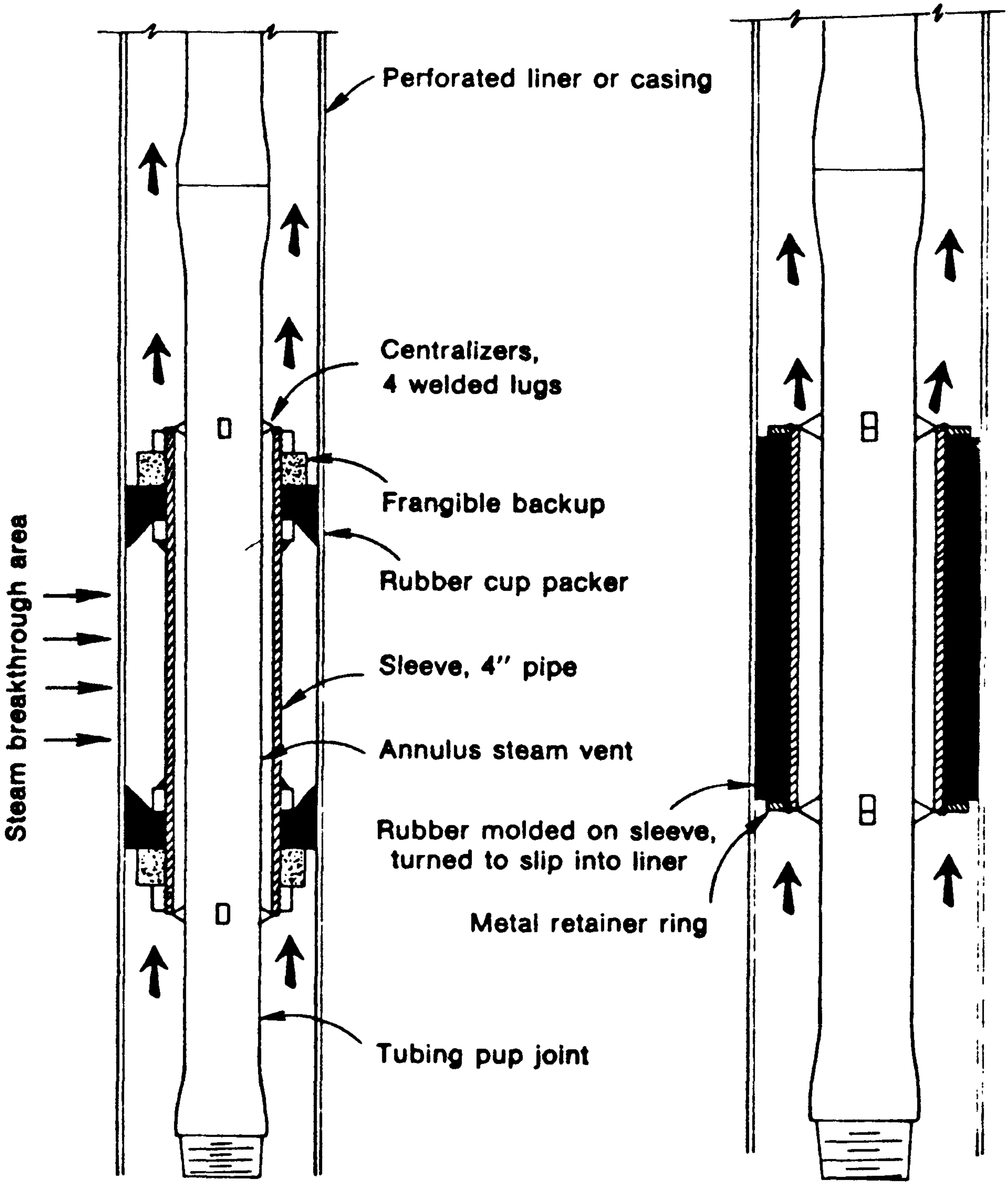

Fig. 2.12: TWO PACKER ASSEMBLIES FOR ISOLATING STEAM BREAKTHROUGH IN A PRODUCING WELL. CUP TYPE (LEFT) HAS EASY WASHOVER CAPABILITY AND LENGTH IS VARIABLE. SOLID PACKER (RIGHT) IS TURNED DOWN TO SLIP SNUGLY INTO A PERFORATED LINER OR CASING (Ref. 43).

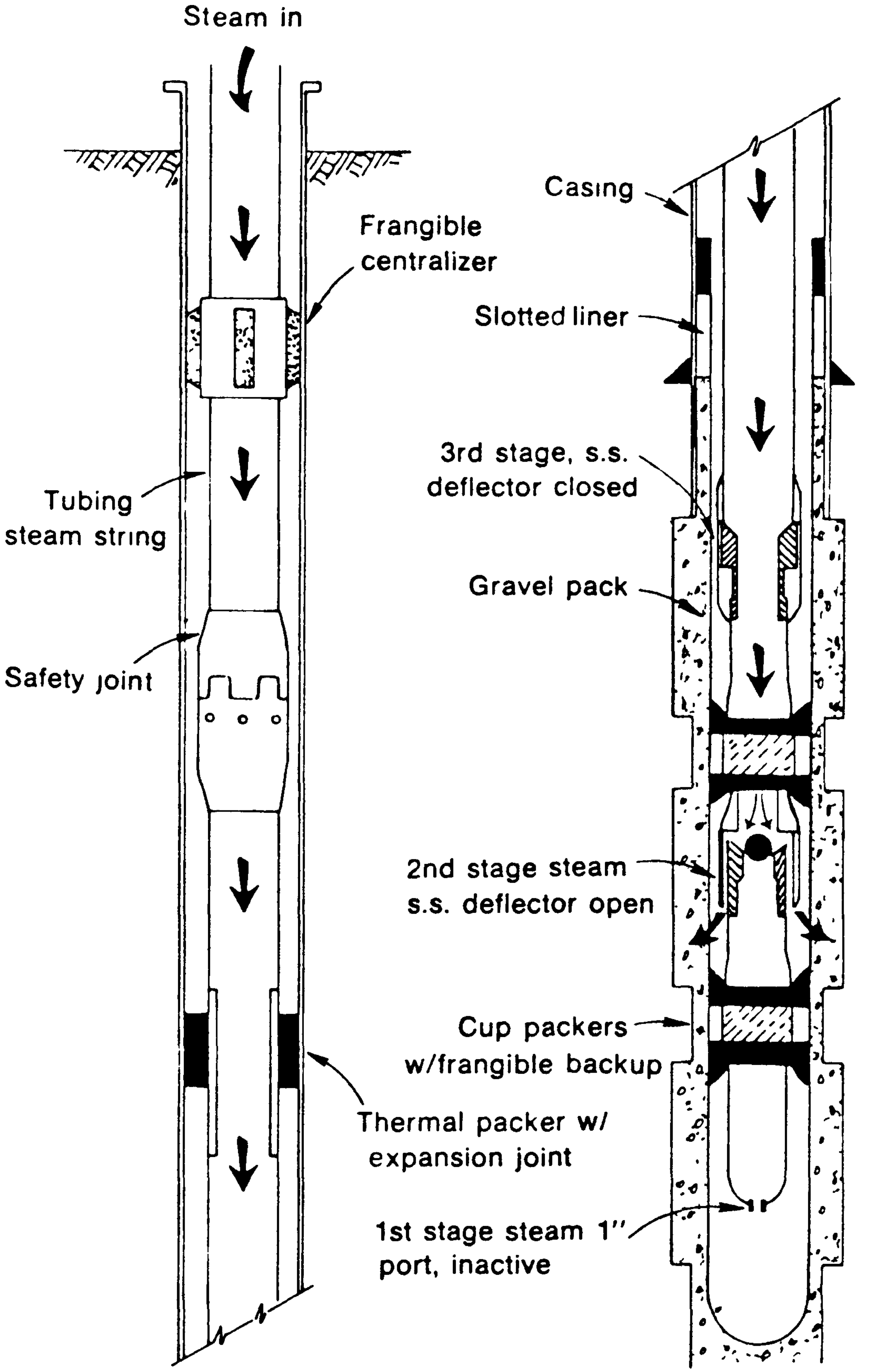

Fig. 2.13: SCHEMATIC OF TYPICAL APPLICATION OF THERMAL EOUTPMFNT IN A SEQUENTIAL, MULTIPLE ZONE STEAM STIMULATION. BALL HAS BEEN DROPPED AND SECOND INTERVAL IS RECEIVING TOTAL STEAM FLOW. LARGER BALL WILL OPEN THIRD STAGE FOR FINAL STEAM TREATMENT (Ref. 43).

and the maximum heat flux. Injecting steam into a limited interval at high rates sequentially, such as can be done with sliding sleeve valves and packer cups, is desirable based upon the mathematical model of Sather[32] and the field demonstration reported by Hutchison.[43] In several California oil fields, it has been shown that steam splitting and zonal segregation improve productivity and economics. Multiple-zone steam stimulation is possible with the typical equipment shown in Fig. 2.13.

2.7.6 Low-Heat Conductance Centralizer

Using stell devices to centralize tubing inside the casing is a poor idea in steam injection wells because of its good conductivity. In addition, it is difficult to washover or mill up. Use of low-heat conductance material that is frangible would provide an improved method of centralizing tubing in thermal wells. Figure 2.14 is a cross-sectional view of a cordierite centralizer lug showing how it is held on the tubing by the metal retaining webs holding the lug heel.

2.8 GOVERNMENT REGULATIONS FOR DRILLING AND CEMENTING OF WELL

In the United States, forty-three of the fifty states have agencies regulating the drilling and cementing of wells. The regulating bodies govern the method of setting casings, volume of cementing, testing of cement jobs, squeezing, plugging, and testing of cement plugs, and protection against pollution of fresh water. In the areas of their jurisdiction, these regulations represent a uniform practice for the drilling and cementing of casing. Most rules are not absolute or rigid, but are flexible within areas or fields. When proper evidence is presented, operators are often allowed to modify certain practices.

The State of California's Division of Oil and Gas defines general rules[6] to be followed, yet is flexible enough to allow engineers to exercise their own judgment in some areas. These general rules fall into sections, depending on the type of hole:

1) In dry holes or uncased wells, any oil show must be coverd with cement. The interface between fresh water and salt water must be covered by at least 100 linear feet of cement, and there must be a minimum plug of 25 ft at the surface.

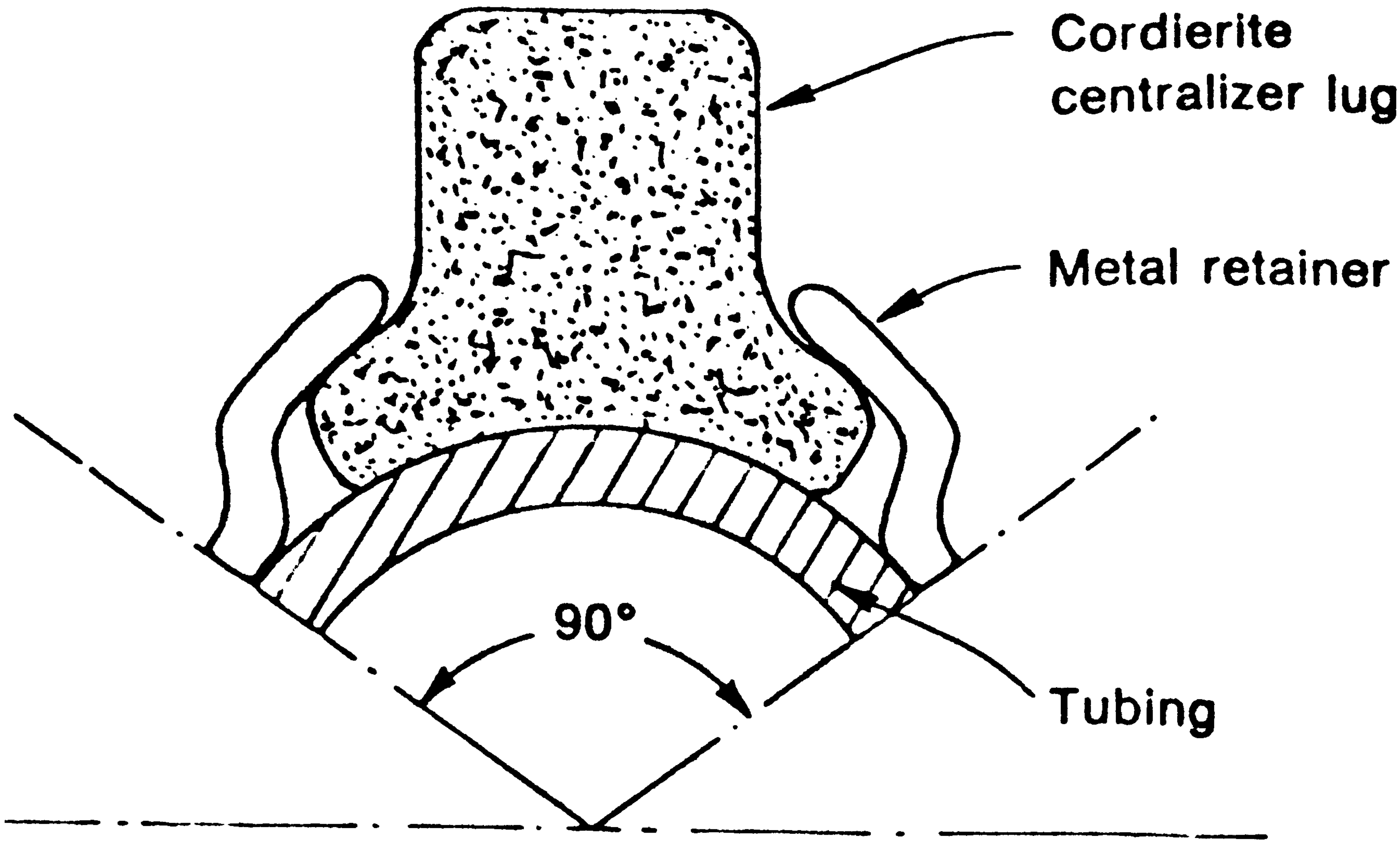

Fig. 2.14: CORDIERITE CENTRALIZER-LUG (Ref. 43)

2) In cased holes, all zones must be covered or protected with a minimum of 100 ft of cement above the top producing zone. The salt-water/fresh-water interface must also be protected with at least 100 ft of cement. A water shutoff test is required immediately above the top producing zone, and can be made by wire line. In some cases, such a test is waived by the state inspector.

In most states, operators must file a notarized application covering details of the intention to drill a well. This application must describe casing and cementing programs. Upon completion of the well, a notarized well completion report on casing and cementing data must be filed. If the well is non-productive, an application must be filed to plug and abandon it (and perhaps to pull the casing) with full details of the proposed plan. Upon completion of that work, a detailed plugging record must be supplied.

2.9 TYPICAL WELL SET-UPS

Figures 2.15 and 2.16 show the schematic configuration of a typical producing well and a typical injection well, respectively, in a steam drive project in the Kern River area.

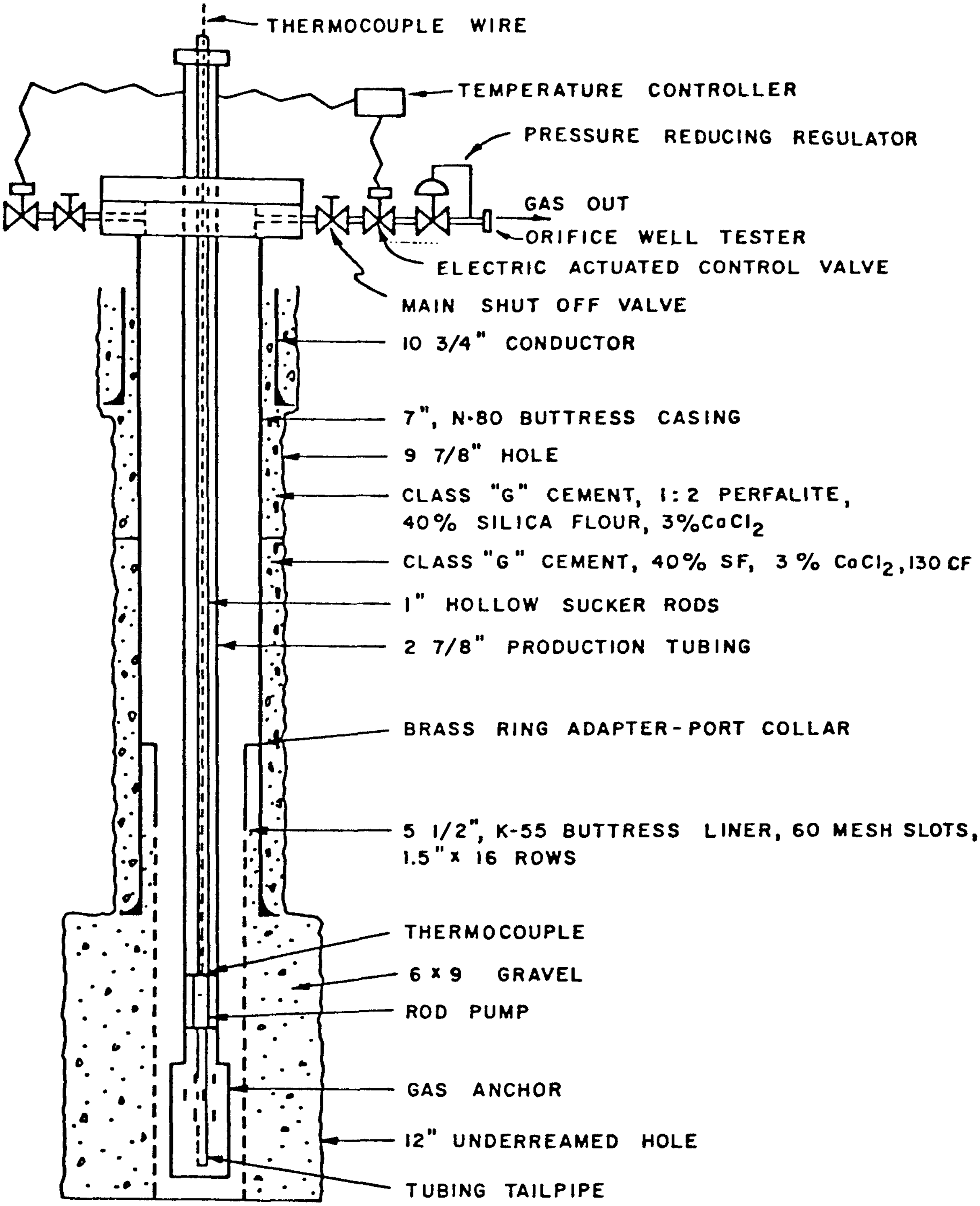

Fig. 2.15: TYPICAL PRODUCTION WELL (Ref. 7)

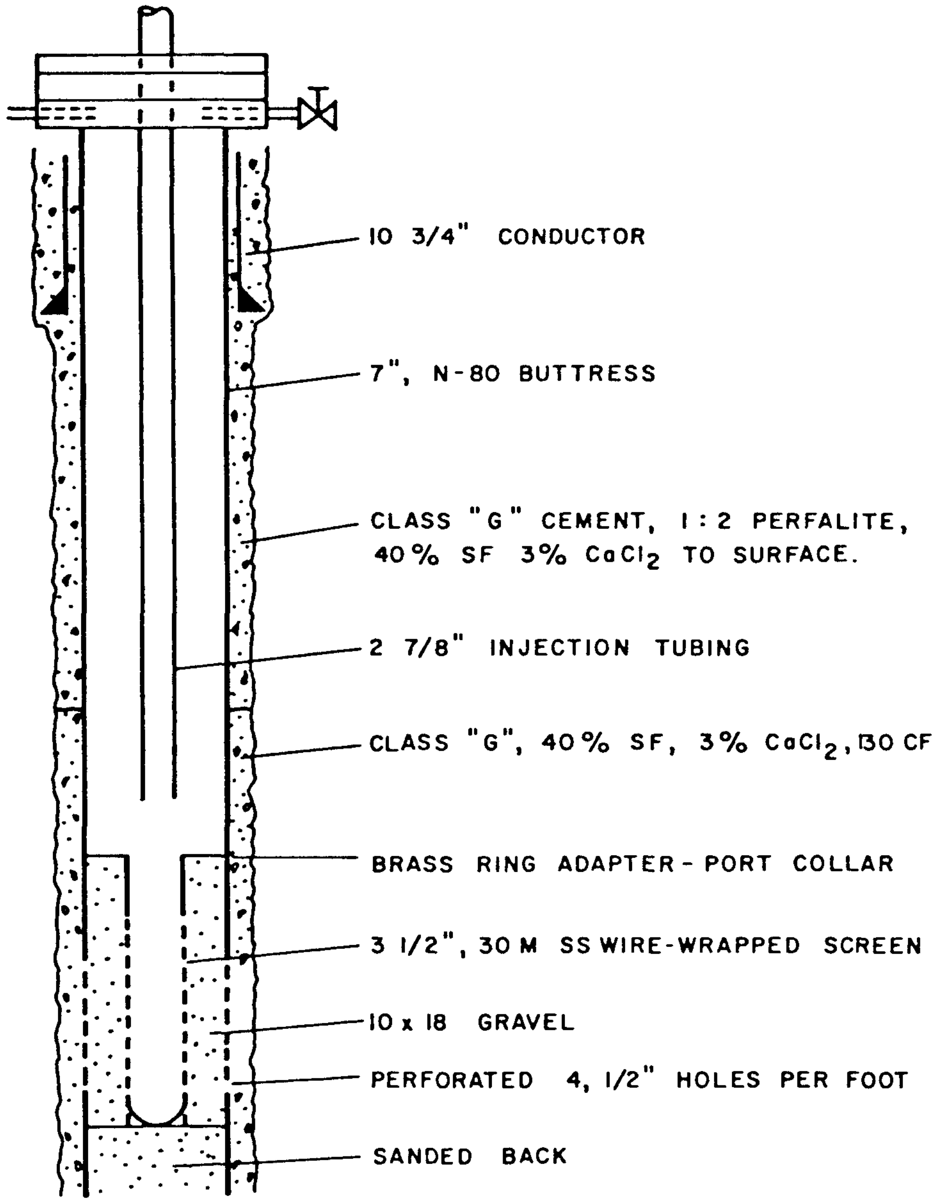

Fig. 2.16: TYPICAL INJECTION WELL (Ref. 7)

3. WATER TREATMENT FOR STEAM GENERATION

3.1 WATER SUPPLY

Water treatment requirements for steam injection are much more critical than those usually needed for conventional oilfield water flooding or operation of field boilers. Most of the water for steam generation will probably require treatment by ion exchange processes or chemical precipitation processes or both. The water supply for steam generation must be:

1) Abundant enough to take care of present and future requirements;
2) Available at sufficient flow rates and pressure to meet all peak demands and provide adequate fire protection; and
3) Of suitable quality for its various end uses.

The most important step in the design of a water treatment system is a complete, accurate and representative series of water analyses. Natural water sources can be divided into the following groups.[13]

3.1.1 Surface Sources

1) Moving supplies (rivers, creeks)--generally contain mud, silt, other suspended matter and dissolved minerals. In some cases color, waste products and sewage are present.
2) Static supplies (lakes, reservoirs)--generally contain dissolved gases and dissolved minerals. Also bacteria, algae, and other organic matter may be present. The amount of suspended matter is usually low due to natural settling, but shallow lake bottoms are easily disturbed by storms.

3.1.2 Underground Sources

1) Water wells--the filtration effect of earth reduces suspended matter, organic matter, and algae, but increases dissolved mineral content. In general, the deeper a well the more highly mineralized the water will be.

2) Produced water (from oil wells)--it is usually contaminated with oil, sometimes contains hydrogen sulphide, and may be extremely mineralized (often in excess of 20,000 ppm). Occasionally such water will contain considerable organic matter and might even have a high redox potential.

Table 3.1 lists the more common impurities and shows an approximate comparison between an underground and a surface water supply. The differences are substantial and methods to produce the same purity from various sources will vary considerably. Besides the basic differences in the two natural water sources, it is highly improbable that two surface sources or two wells supplying water with identical analyses can be found.

The majority of oilfield steam generators used for steam flooding is of the "once-through" type (single pass). Wet steam is produced by these generators. A once-through thermal unit or field heater producing 70% quality steam will concentrate feedwater constituents 3 1/3 times. At 80% steam quality, there will be a five-fold concentration, and at 90% a ten-fold concentration. Obviously, the higher the steam quality desired, the more carefully must feedwater constitutents be controlled. Solubilities and corrosiveness of water components also are dependent on operating temperatures and pressures.[12]

3.2 WATER QUALITY REQUIREMENTS

Burns[13] has shown that the feedwater to once-through field heaters must meet three criteria.

3.2.1 Suspended Solids

In using one-through field heaters, feedwater must be free of constituents in excess of the following amounts: matter (5 ppm), iron (0.4 ppm), manganese (0.1 ppm), sulfides or hydrogen sulfide gas (0.1 ppm), organic matter (as close to zero as possible), and oil (0 ppm). A typical ion-exchanger is designed to handle impurities as mentioned in parentheses. The treated fianl feedwater should have all of the above contaminants reduced to as close to zero as possible.

TABLE 3.1 COMMON IMPURITIES IN WATER (Ref. 13)

Constituents	Well Water (ppm)	River Water (ppm)
Calcium (Ca^{++})	350	60
Magnesium (Mg^{++})	150	20
Sodium (Na^{+})	100	50
TOTAL CATIONS	600	130
Bicarbonate (HCO_4^{-})	250	50
Carbonate (CO_3^{--})	0	0
Hydroxide (OH^{-})	0	0
Chloride (Cl^{-})	100	50
Sulfate (SO_4^{--})	245	30
Nitrates (NO_3^{-})	5	0
TOTAL ANIONS	600	130
Total Hardness	500	80
Free Carbon Dioxide (CO_2)*	130	6
Iron (Fe)*	0.4	0.2
Manganese (Mn)*	0.1	0
Silica (SiO_2)*	19	5
Turbidity*	1	600
Color*	0	10
pH*	6.6	7.1
Organic Matter*	0	1.5

* All values are parts per million as $CaCO_3$ except those indicated with an asterisk.

The equipment to remove suspended matter is called the primary equipment. Fortunately, most supplies meet the above specifications, and hence, no primary treatment is necessary. This is particularly true for the usual fresh water supplies such as tap water which has undergone primary treatment. Certain well supplies and produced waters have required only a minimum or pretreatment (using oil removal filters or simple pressure filters) and have been economical to use.

3.2.2 Hardness

Feedwater should have no hardness--the scale-forming calcium and magnesium ions (hardness) must be completely eliminated. Other constituents, such as the total dissolved solids (TDS), alkalinity, and dissolved silica will present little or no problem in a wet-steam system as opposed to a conventional dry-steam blow-off system. The water phase will consist exclusively of extremely soluble sodium salts (all hardness eliminated), and as such will sweep through the field heater.

3.2.3 Gases

Feedwater must be free of corrosive gases such as hydrogen sulfide, oxygen and carbon dioxide. The preferred method of treatment is a combination of mechanical deaeration with supplementary chemical feeding. Sodium sulfite is fed to maintain a small residual for oxygen scavanging in the deaerator storage, and filming or volatile neutralizing amines are used for corrosion control. Use of these chemicals is especially valuable when the generator is shut down, because air infiltration can then result in absorption of oxygen and carbon dioxide by the water. The mechanical deaerator can be eliminated in some cases (to reduce initial cost) and chemical dearation used alone. However, for some operations, this small savings in cost cannot be justified when the advantages of mechanical deaeration are evaluated. These advantages[13] are:

1) Proper chemical deaeration of cold water dictates that the use of "catalyzed" sodium sulfite at the ratio of about 8 ppm of sulfite to each ppm of oxygen will dissolve in any water at 70°F and atmospheric pressure. In addition, a sulfite residual of at least 20 ppm should be maintained. On the other hand,

a mechanical deaerator reduces oxygen to less than 0.007 ppm so that the only sulfite necessary is that required to maintain a residual. Depending on system capacity, the savings in sulfite might pay for the deaerator in a short time. Each specific should be evaluated by the potential user.

2) The deaerator uses live steam from the generator for its operation. Therefore, it serves as a thermodynamically-efficient direct contact preheater, which eliminates preheating equipment from the generator package with consequent savings.

3.3 EQUIPMENT FOR WATER TREATMENT

Table 3.2 lists the more common impurities in water, and the recommended[13] equipment for their reduction or removal. Capacities of water treatment equipment have ranged from a low of 12 to a maximu of 3,200 gal/min. The most popular and widely used size lies in the range of 60 to 120 gal/min for a single water treatment plant. For the pilot study, the equipment should be mounted and factory packaged on oil-field type skids for portability and ease of installation. Preferably these installations should be automated.

Sodium-cation exchanger (zeolite) water softeners are made in both the pressure type and the gravity type and either type is available in automatic, semi-automatic or manually operated designs. All these operate on the same principle of a cycle consisting of the softening run and regeneration. On the softening run, the water is softened by flowing through the sodium-cation exchanger bed which removes and holds calcium and magnesium and gives up an equivalent amount of sodium in exchange. The schematic of a typical ion exchanger is shown in Fig. 3.1.

The regeneration consists of three steps: backwashing, salting (brining), and rinsing. Backwashing is accomplished by sending a strong flow of water upwards through the cation exchange bed which serves to expand, cleanse and hydraulically regrade it. In salting or brining, a predetermined amount of salt brine is passed through the cation exchange bed, reacting with it to remove calcium and magnesium from the bed source. This pilot plant should have a fully-automated operation of sodium-cation exchanger water softeners. There are a number of advantages to the automatic sodium cation exchanger water softeners. One of these is that

TABLE 3.2

WATER TREATMENT EQUIPMENT (Ref. 13)

IMPURITY	METHODS FOR REMOVAL OR REDUCTION
H_2S Gas	1 alone 1 with 18 1 with 18 and 20 10
CO_2 Gas	1, 2, 3, 12, 14, 19, or 22
O_2 Gas	2, 3, 21, 22, or 22 with 23
Turbidity or Sediment	6 for small amount of coarse sediment 6 with 15 and 16 4 with 14, 16, 17 and 6 7 for small amount of turbidity
Color, Organic matter	Same as above but with possible additions
Bacteria	of 20, 18, and 23
Oil	6 with 15 and 16 7
Hardness	4 with 14, 16 and 6 4 with 14, 15, 16 and 6 31 with 14 and 6 13 with 14, 15 and 6 8 or 9, or 12, or 24
Alkalinity	18 with 1, 2, or 3 9 with 1 and 19 9 and 8 blend with 1 8 with 10 8 with 11 12
Na^+ Cation	9 or 12
SO_4^- Anion	8 with 10 8 with 11 12
NO_3^- Anion	12
Cl^- Anion	12
Fe^{++} and Mn^{++}	Compressed air with 6 1 with 6 1 with 14 or 19 and 6 5, 8, or 9 occasionally
Silica	13 with 14, and 6 13 with 14, 15, and 6 8 with 11 12
Chlorine Residual	22 or 23

KEY TO METHODS FOR REMOVAL OR REDUCTION	
1.	Aeration
2.	Cold Vacuum Deaeration
3.	Hot Deaeration
4.	Sludge Contact Clarifier
5.	Contact Filtration
6.	Sand or Anthracite Filtration
7.	Precoat Filtration
8.	Sodium Zeolite (Hot or Cold)
9.	Hydrogen Zeolite
10.	Chloride Anion
11.	Anion Salt Splitter
12.	Demineralizer
13.	Hot Process Sedimentation
14.	Lime Feed
15.	Soda Ash Feed
16.	Coagulant Feed
17.	Coagulant Aid Feed
18.	Acid Feed
19.	Caustic Feed
20.	Chlorination
21.	Special Ion Exchange
22.	Special Chemical Feed
23.	Activated Carbon Purification
24.	Micro Softening

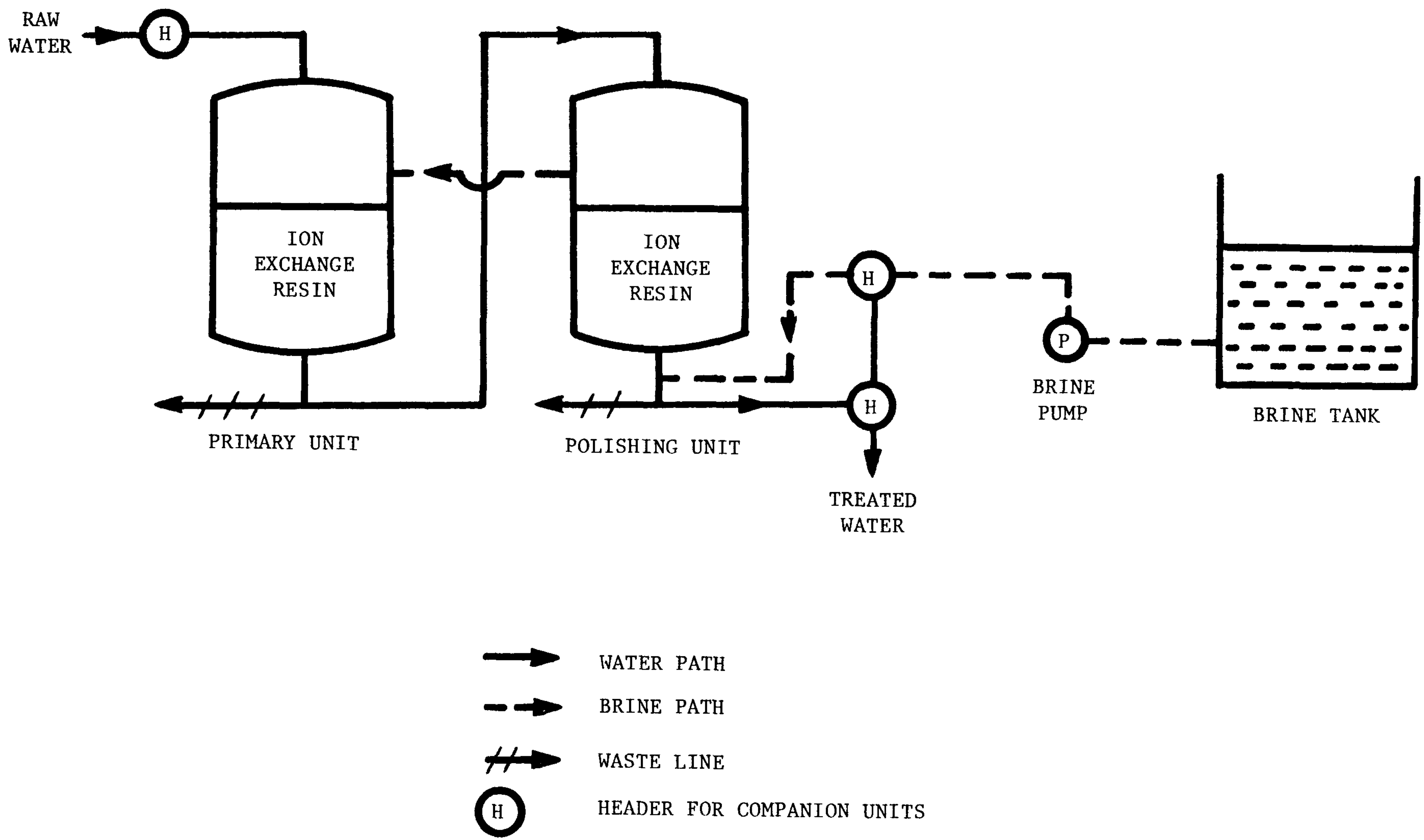

Fig. 3.1: SCHEMATIC DIAGRAM, ION EXCHANGE UNIT (Ref. 12)

it eliminates the danger of hard water getting into the softwater lines by over-running. This frequently happens with manually-operated softeners when the operator is off duty, or is busy at some other task and therefore is not immediately available at the end of a softening run. Another advantage, and the importance of this can hardly be overstressed, is that the automatic water softener does exactly what it is set to do in exactly the same way each time. The advantages outweigh the additional cost of an automated system.

3.4 GENERAL FEATURES OF STEAM GENERATORS

The steam generator can be considered to be the most important of the surface facilities. Figure 3.2 shows the schematic of a steam generation system. The one-through steam generator has been specifically developed for thermal recovery applications and features a single pass of water through the generator coil without a separating drum. The units are generally designed to produce approximately 80% quality steam, so that the weight ratio of water-to-steam at the outlet of the generator is about 1:4, which is a much lower ratio than in conventional boiler designs. Specific features of the once-through generator not available in conventional steam boilers include:

1) The generator will handle feedwater with a relatively high percentage of solids, provided the solids have been converted to a soluble form.
2) The generator is basically a pipe coil, and has no separating drum. Because of the small volume of water and/or steam contained in the coil and the lack of a drum, it does not conform to the classic definition of a boiler.
3) It does not have level controls, low level cutouts, etc., as required in a conventional boiler installation, and does not require continuous blowdown and constant operator attendance.

Feedwater treatment is an important consideration in the satisfactory performance of a once-through generator and due to its special significance, has already been considered in a separate section. A small (22 MM BTU/hr) steam generator is required for the pilot test, the specifications for which are discussed in the rest of this section

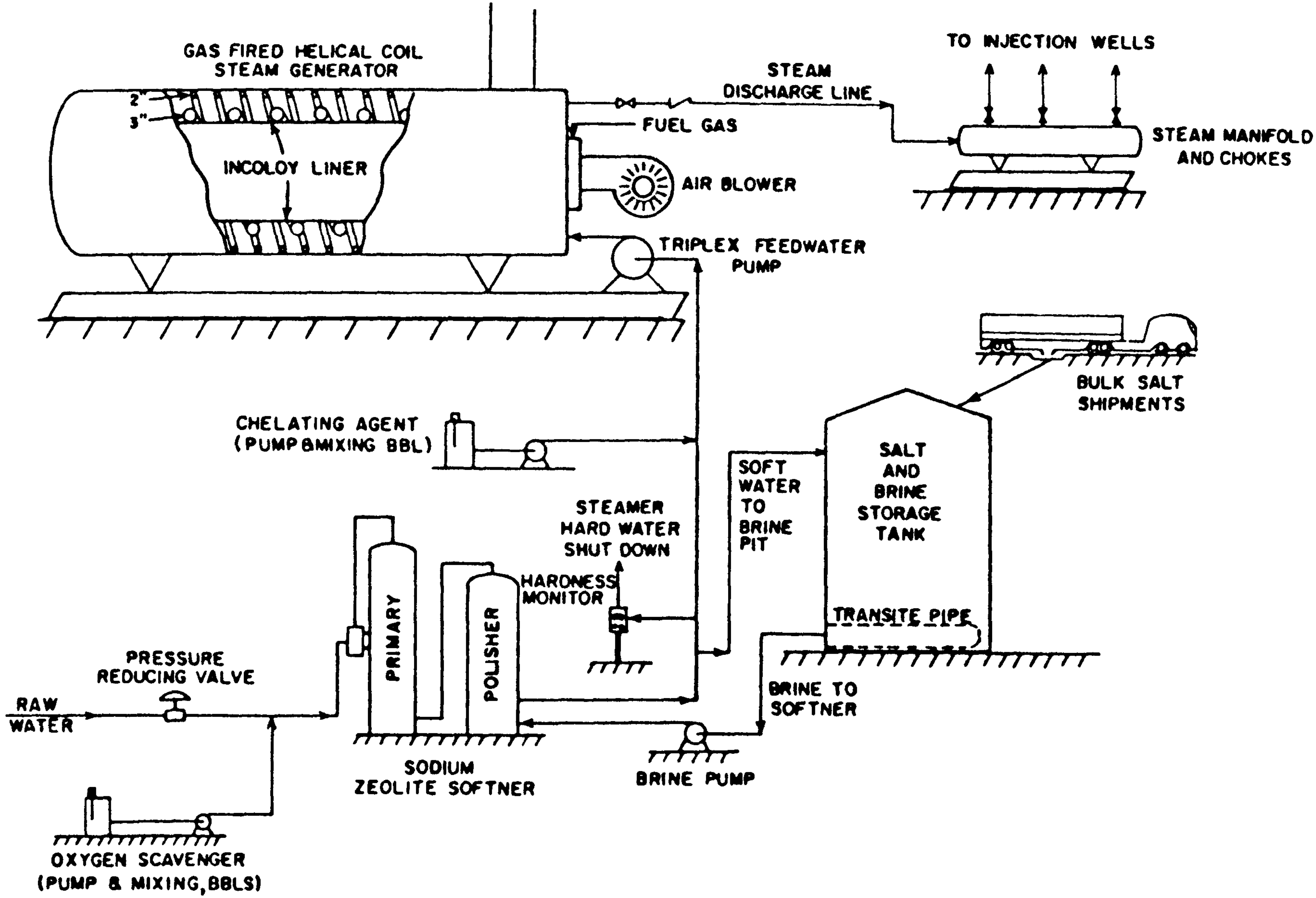

Fig. 3.2: COMPLETE STEAM GENERATION SYSTEM (Ref. 16)

3.5 DESIGN OF STEAM GENERATOR TUBE

Helical and straight tube coil designs are available in the types of steam generators most widely used in the oil fields. For the pilot plant, the generator should have 2-in. and 3-in. schedule 160 helical coils with a maximum rating of 1,500 psi. Water enters the firebox and of the generator and passes through the 2-in. coils which are in helical configuration against the refractor lining of the outer shell. The fluid then passes through the 3-in. coils which are located between 2-in. coils and the incoloy liner, and returns to the firebox end where it is discharged as 80% quality saturated steam. The incoloy liner, which runs the length of the radiant section, protects the coils from direct flame impingement (Fig. 3.3). Any changes of inlet water temperature should be taken into consideration when operating a steam generator. Convection sections are available as a means of increasing the temperature of the feedwater before the water enters the generator. The over-all efficiency of the unit is improved since the heat contained in the stack gases is transferred to the feedwater in the convection section rather than being taken up in the stack.

3.6 PRESSURE DROP AND HEAT REQUIREMENT IN STEAM GENERATOR

It is essential that a reasonably high velocity of the fluids be maintained through the tubes of the generator to achieve an internal heat transfer film coefficient which will assure a minimum tube wall temperature. It is also desirable to use a series flow coil to avoid the potential distribution problems of coils having two or more parallel passes. To meet these conditions, it is usual practice to have a pressure drop of 100 to 200 psi through a one-tube generator.

Determination of the heat required to generate steam of any quality over a wide range of pressures and at any feedwater inlet temperature is extremely important and it is developed in Ref. 15. As an example, the total heat required to product 20,000 lb/hr of 80% quality steam at 1,000 psi with 50°F feedwater is:

Outlet enthalpy from chart (from Steam Tables)	1,070 BTU/lb
Enthalpy of feedwater	18 BTU/lb
Net outlet enthalpy	1,052 BTU/lb

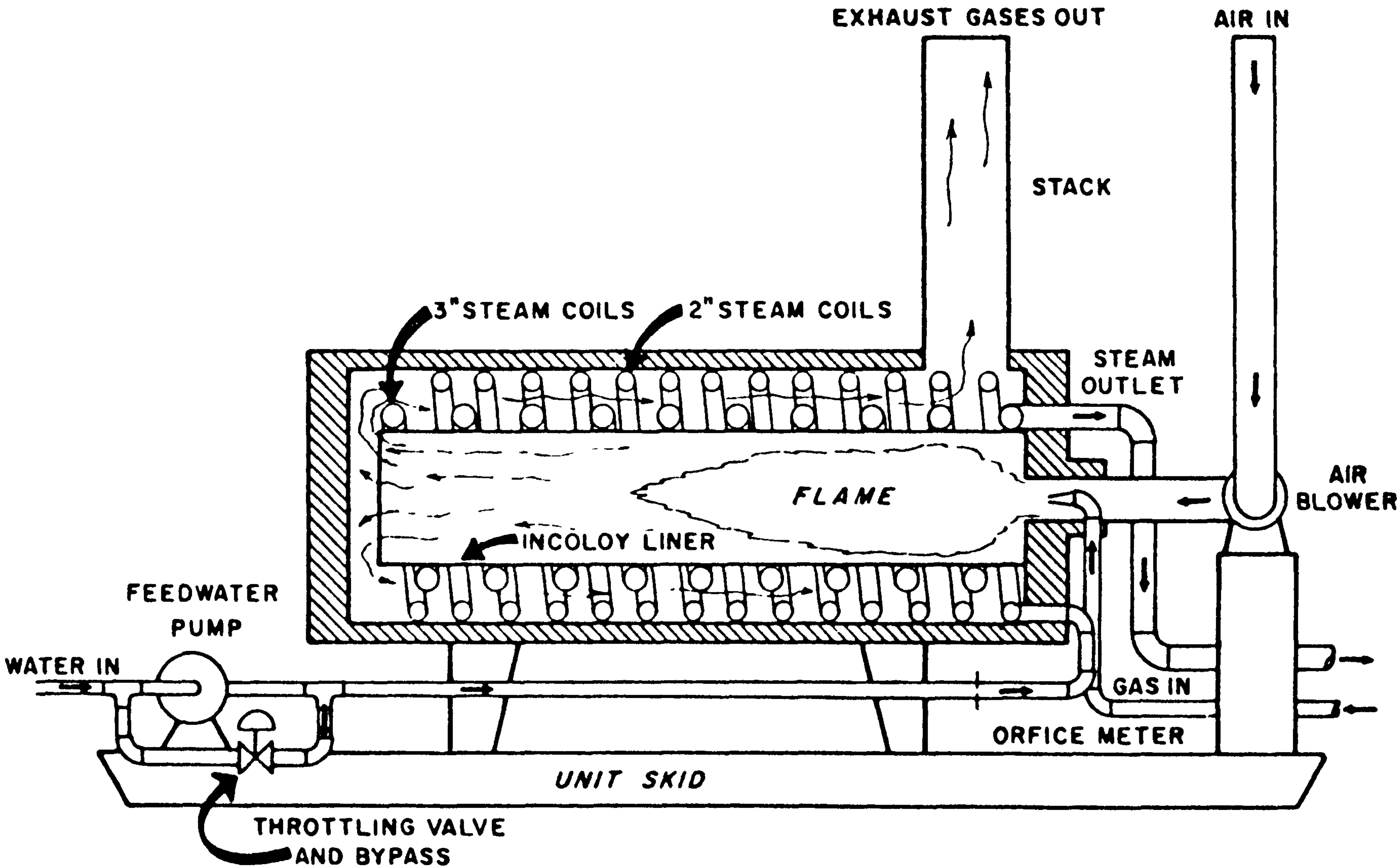

Fig. 3.3: FLOW SCHEME THROUGH A SINGLE-PASS HELICAL COIL STEAM GENERATOR (Ref. 52)

Therefore, the heat required to produce the steam is:

$$20,000 \ \frac{\text{lb}}{\text{hr}} \times 1,052 \ \frac{\text{BTU}}{\text{lb}} = 21,040,000 \ \frac{\text{BTU}}{\text{hr}}$$

Similarly, if the total heat load (BTU/hr) has been preselected, the division of the heat load by the net enthalpy as determined above will give the amount of steam generation of selected quality in pounds per hour.

The calculation of pressure losses in lines handling the liquid-vapor mixture is quite laborious and requires a great deal of experience. Fanaritis[15] published methods for the rapid approximate determination of the pressure loss in the external piping between the generator and the well (Fig. 3.4). This chart can be used over a steam quality range of 75% to 90%.

3.7 GENERATOR THERMAL EFFICIENCY AND HEAT LOSSES

Fanaritis[15] designed a method (Fig. 3.5) for the rapid determination of generator thermal efficiency from the flue gas temperature and flue gas analysis. Only two fuels are covered in the figure; however, curve A can be used for most heavy liquid fuels, and curve B can be used for natural gas over a range of 800 to 1200 BTU/SCF LHV (Lower Heating Value). In using this figure, one must measure the stack gas temperature and project a line vertically upward from the temperature to the appropriate curve. The gross thermal efficiency is read from the left scale. Deduct 1.5% from the efficiency thus determined to correct for radiation losses to the atmosphere. Percentage of excess air in the flue gas can be determined by an Orsat analysis of the gas.

Figure 3.6[15] is designed to permit approximate determination of heat losses form uninsulated transmission piping between the generator and the well. The total heat loss can be calculated from Fig. 3.6 given the length and diameter of pipe, steam quality and temperature, and the ambient temperature and wind velocity. In the petroleum industry it is considered uneconomical to transfer steam beyond three-quarters of a mile even with good insulation.[51]

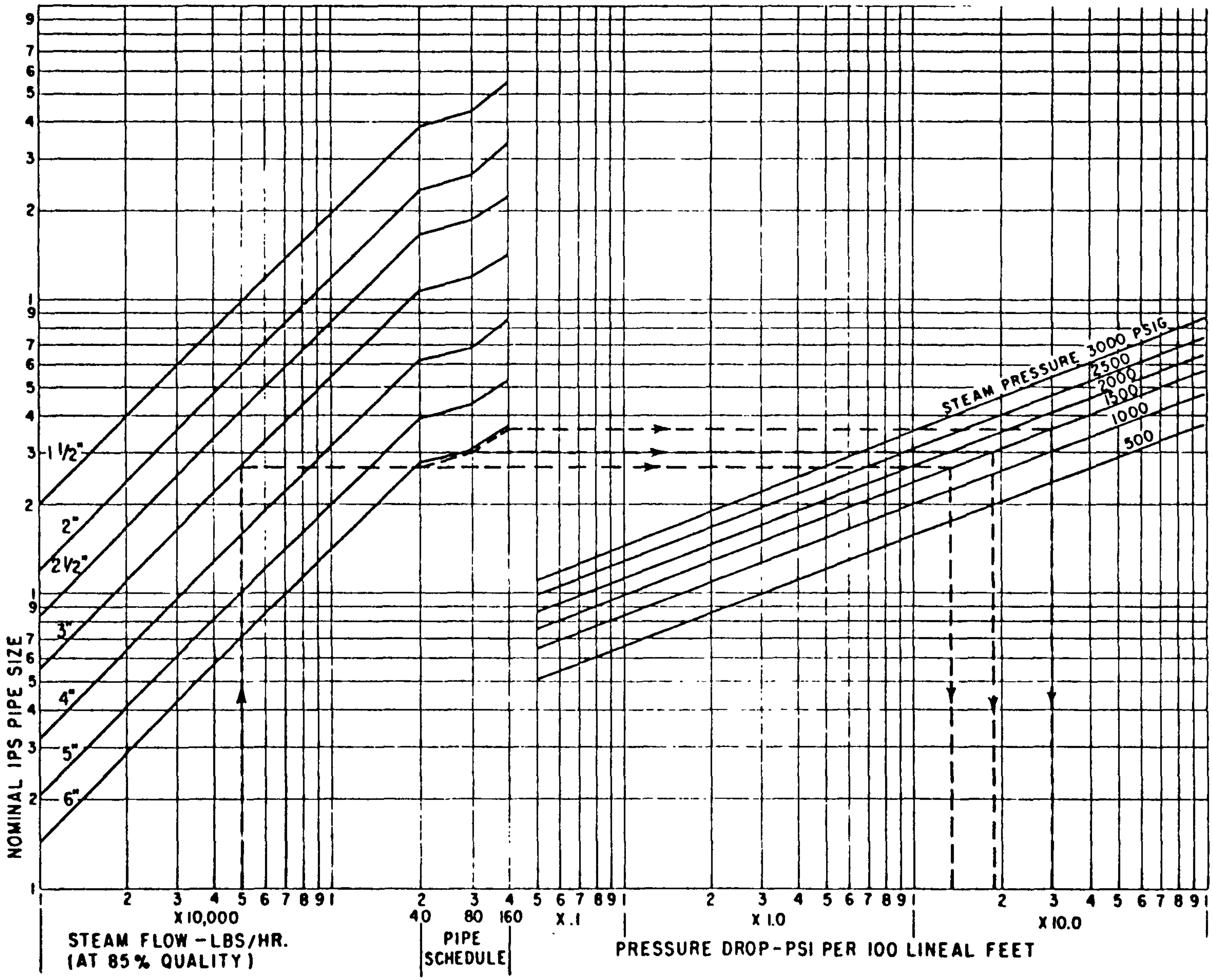

Fig. 3.4: PRESSURE DROP OF LOW-QUALITY STEAM IN STANDARD PIPING (Ref. 15)

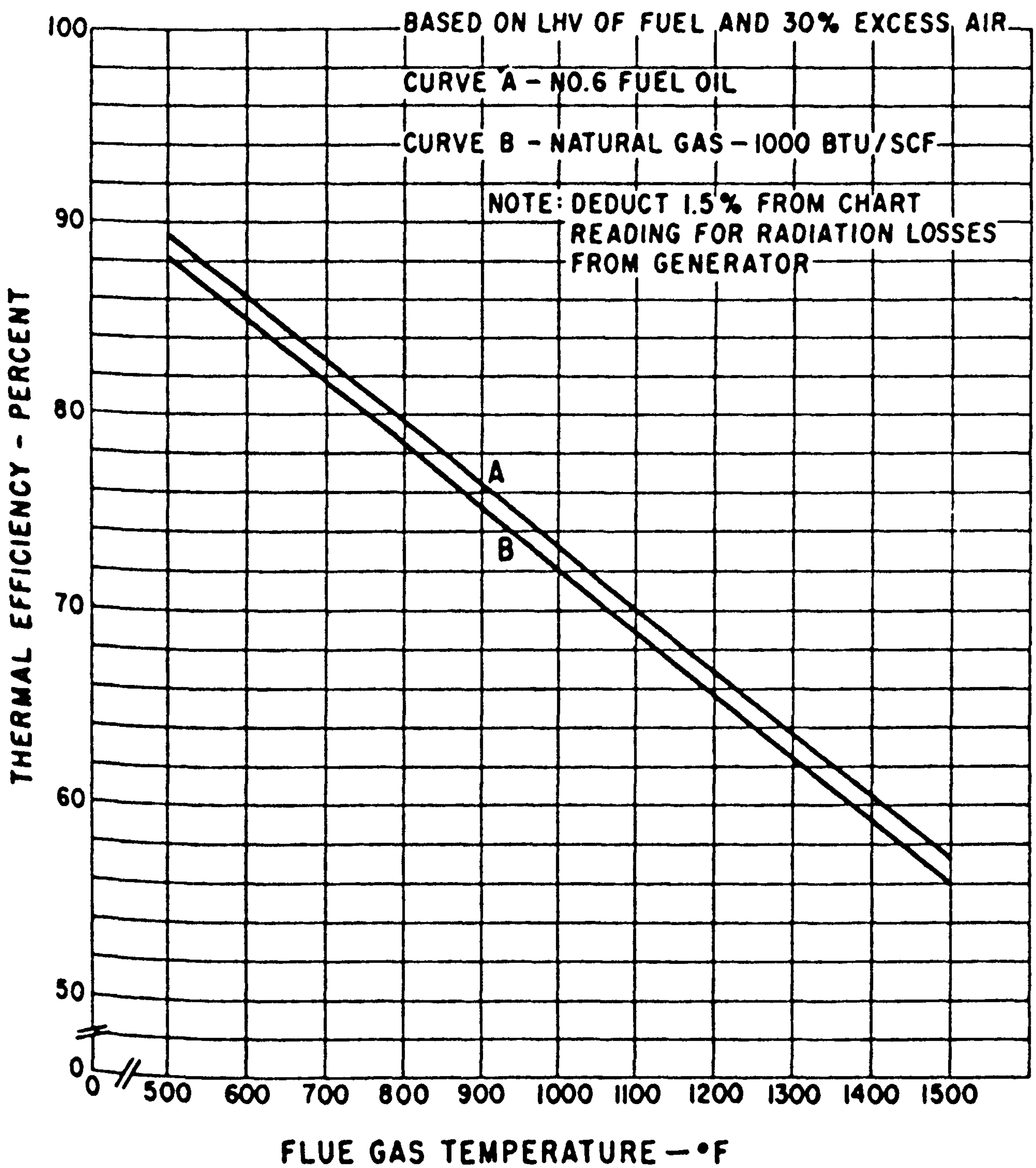

Fig. 3.5: GENERATOR THERMAL EFFICIENCY (Ref. 15)

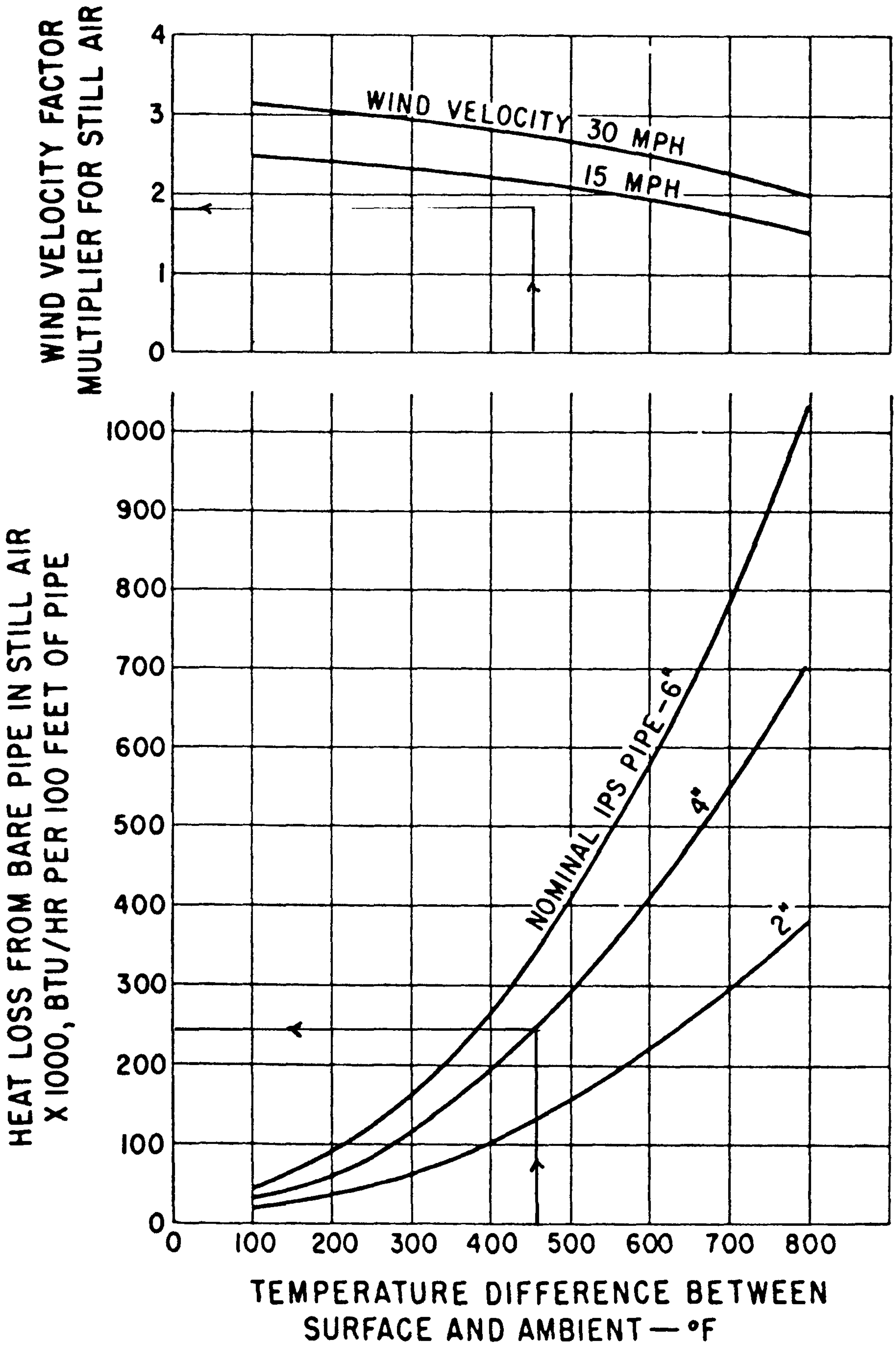

Fig. 3.6: HEAT LOSS FROM BARE PIPE IN STILL AIR WITH WIND VELOCITY EFFECT (Ref. 15)

3.8 OPERATION AND MAINTENANCE OF STEAM GENERATOR

The cost of operating a gas-fired steam generator is less than that of an oil-fired generator.[16] The higher cost for an oil-fired generator is mainly due to the increased maintenance and labor costs. The large-scale steam operations, gas from the lease or pipeline or both is not always available. In any case, crude is a more reliable and abundant source of fuel. A high level of thermal efficiency can be achieved and maintained with oil-fired steam generators provided good combustion is attained. One of the most important steps in attaining good combustion is supplying the burner with oil at the correct temperature.

3.8.1 Preheating the Fuel Oil

Preheating the fuel oil is important because as heavy oil is heated, its viscosity decreases and consequently: 1) it makes the oil easier to circulate; 2) make the burner manifold pressure easier to control; and 3) assists in producing atomization for good combustion. The effect is the opposite when the oil is not heated sufficiently; it becomes viscous, difficult to handle and almost impossible to atomize and burn.

For all practical purposes, pre-heating and atomizing temperatures are the same. However, to heat fuel oil properly, the viscosity and flash point must be known. Knowledge of the viscosity will aid in determining the temperature required to reduce the viscosity for atomizing, and knowledge of the flash point is necessary to limit the temperature for safety.

It is necessary to have the following information about the fuel to be burned: API gravity, viscosity at temperature points, heating value--higher and lower, flash point, and sulfur percent. If the flashpoint is low and the preheating temperature is high, there may be danger of pre-ignition, as the heat will drive off many of the light vapors forming a gas phase which will cause the burner to puff and pulsate. If this happens, the preheating temperature should be reduced. At times, it is necessary to pre-heat the fuel above the flash point in order to reduce the viscosity to the required condition.

The following problems can result from too high a pre-heating temperature:

1) Poor atomization, resulting in poor combustion;
2) Carbon forming on burner nozzle;
3) Pre-ignition, resulting in erratic burner operation, fire, puffing and pulsating;
4) Internal carbonization of fuel-oil preheaters;
5) Fuel-oil pump cavitation, resulting in loss or variation of manifold pressure;
6) Fuel-oil foaming and vaporizing caused by breakdown of lighter hydrocarbons;
7) Soot and carbon formation on burner throat and in combustion area; and
8) Lower fuel input capacity.

The following problems can result from too low a preheating temperature:

1) Poor atomization and poor combustion;
2) Erratic firing of burner;
3) Ignition of burner becoming almost impossible, especially on a cold start;
4) Carbon forming on burner and burner throat;
5) High smoking or soot conditions;
6) Poor manifold or sooting conditions;
7) Blocked strainers and fuel valves;
8) Pumping problems--difficultiy in pumping oil, overloading of pump, etc.; and
9) Inability to get burner capacity.

3.8.2 Control of Burner Operation

The characteristics of the flame and flue gas during burner operation are significant in evaluating the level of control necessary to attain the necessary combustion:

1) A thin, fluttery oil fire means too much steam for atomization.
2) A long, smokey flame may be due to improper burner-tip design, insufficient combustion air or insufficient atomizing steam.
3) A dazzling white oil fire means either too much excess air or too much atomizing steam.
4) An oil burner operating at proper adjustment produces a yellow flame which verges on whiteness.

5) A reddish, dusty-looking flame, with flocks of smoke over the bright past indicates the lack of enough air to burn the fuel.
6) Sparks in the flame may come for a dirty tip, wet steam, solids in the fuel, or water in the fuel.
7) An oil burner properly adjusted produces a clean flame with no trace of smoke.
8) An uneven flame may mean a dirty tip.
9) Failure of ignition may be due to low fuel pressure, a plugged fuel valve, improper design of top or wet steam with slugs of water from the steam line.
10) Puffing in the furnace may be caused by poor tip design, insufficient excess air, or partial stoppage of the burner tip.
11) Rapid choke formation and refractory deterioration may be caused be excessive flame impingement against the burner throat. This is usually caused by the oil-burner being too short, the oil too cold, the flame angle too wide, the oil tip misaligned, too much fuel being burned, too much excess air, or faulty installation of the burner.
12) The flame may be shortened by increasing primary air, increasing the secondary air, or increasing the atomizing steam slightly.
13) Analyze flue gas as often as necessary for CO_2 and O_2 present, and also the flue gas temperature, because these are good indicators of thermal efficiency.

3.8.3 Other Operation and Maintenance Techniques

Since the steam generator is the most expensive equipment in this operation, it is imperative that proper maintenance techniques are used. The following are some other relevant maintenance techniques:

1) During shutdown, heavy oil lines should be flushed out with diesel oil.
2) Soot blowers should be operated as often as necessary; they retard plugging of convection sections.
3) Convection sections on oil-fired units should be kept clean. The frequency at which these sections must be cleaned varies greatly, depending on how closely the combustion mixture is maintained and controlled.

4) The overall thermal efficiency is very important. Poor maintenance and operation will increase costs proportionally to thermal efficiency losses.

5) Steam generators should operate at full capacity and at a minimum of 80% quality to keep down the injection cost per barrel. The steam quality should be tested daily.

4. SURFACE PRODUCTION EQUIPMENT

An important part of the field pilot is the design, operation and maintenance of the surface equipment required in oil production and steam and chemical injection. This section discusses the relevant operations from the wellhead to the pipeline or to any other transportation point.

4.1 GATHERING SYSTEM

The gathering system consists primarily of pipes, valves and fittins necessary to connect the wellhead to the separation section. Accessory items include gross production meters, systems for injecting corrosion inhibitors and other chemicals, automatic routing valves, and production-limiting devices.

A steam injection system primarily consists of (1) a steam generator, (2) a water conditioning system for feedwater to the steam generator, (3) a main steam header to various oil production-steam injection manifolds that are located in the central part of the wells to be steamed, (4) a series of lines to each individual well, (5) a common test line from the above-mentioned manifold, and (6) a group of oil lines from the producer well manifold, and (6) a group of oil lines from the producer well manifold back to the dehydration facility.

Foamer solution can be injected from the steam injection system with proper valve connections and fittings.

4.2 TREATING SECTION

The treating section consists of some method of dehydration, such as using wash tanks, heater treaters, or electrical dehydrators. The principal purpose of the treating section is to remove water, sand, and other contaminants from the oil. In most cases, the waste water must be cleaned before disposal. In general, dehydration equipment can be divided into three classes: gravity, electrical and chemical

4.2.1 Gravity Dehydration

Open sumps, wash tanks, heater traters, centrifuges, etc., are included in the gravity class. As implied, the principal force involved in the separation of oil and water is gravity. Centrifuges add mechanical force to aid gravity settling.

Wash tanks: A wash tank is a large tank equipped with a spreader, oil draw-off, level control, and low-pressure separator. Oil enters the low-pressure separator, situated on top of the tank, and is conducted to the bottom of the tank by means of a large-diameter pipe. A spreader attached to the large pipe distributes the oil uniformly over the cross-section of the tank. A level control maintains the oil-water interface at a desired height, usually in the midsection of the tank. Because the spreader is located below the interface, the input oil is forced to rise vertically through a water bath before entering the oil layer. Water settles out of the oil under the force of gravity and clean oil is skimmed from the surface of the oil layer (Fig. 4.1).

Heat is often required to reduce the viscosity of the oil to a value that will promote gravity settling. Application of heat to the oil stream before it enters the wash tank will correct the problem of serious interference of the convection currents in the water butte if the heat is applied internally. Chemicals, such as Tret-O-Lite or Visco,* injected at the wellhead or into the oil stream at the treating section will aid in the resolution of emulsion.

Capacities of wash tanks may be based on three to four barrels of clean oil per square-foot of cross-sectional area per day, when the viscosity of the crude has been reduced to 100 SSU (Saybolt Universal Units) or less.

Heater treater: A heater treater is a pressure vessel operating on the same principle as the wash tank. The main difference is that the heater operates under pressure. Distribution and convection currents, viscosity, and density difference affect the heater treater operation in the same manner as they do the wash tank.

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*Trade marks, Petrolite Corporation and Visco Division of Nalco Chemical Co., respectively.

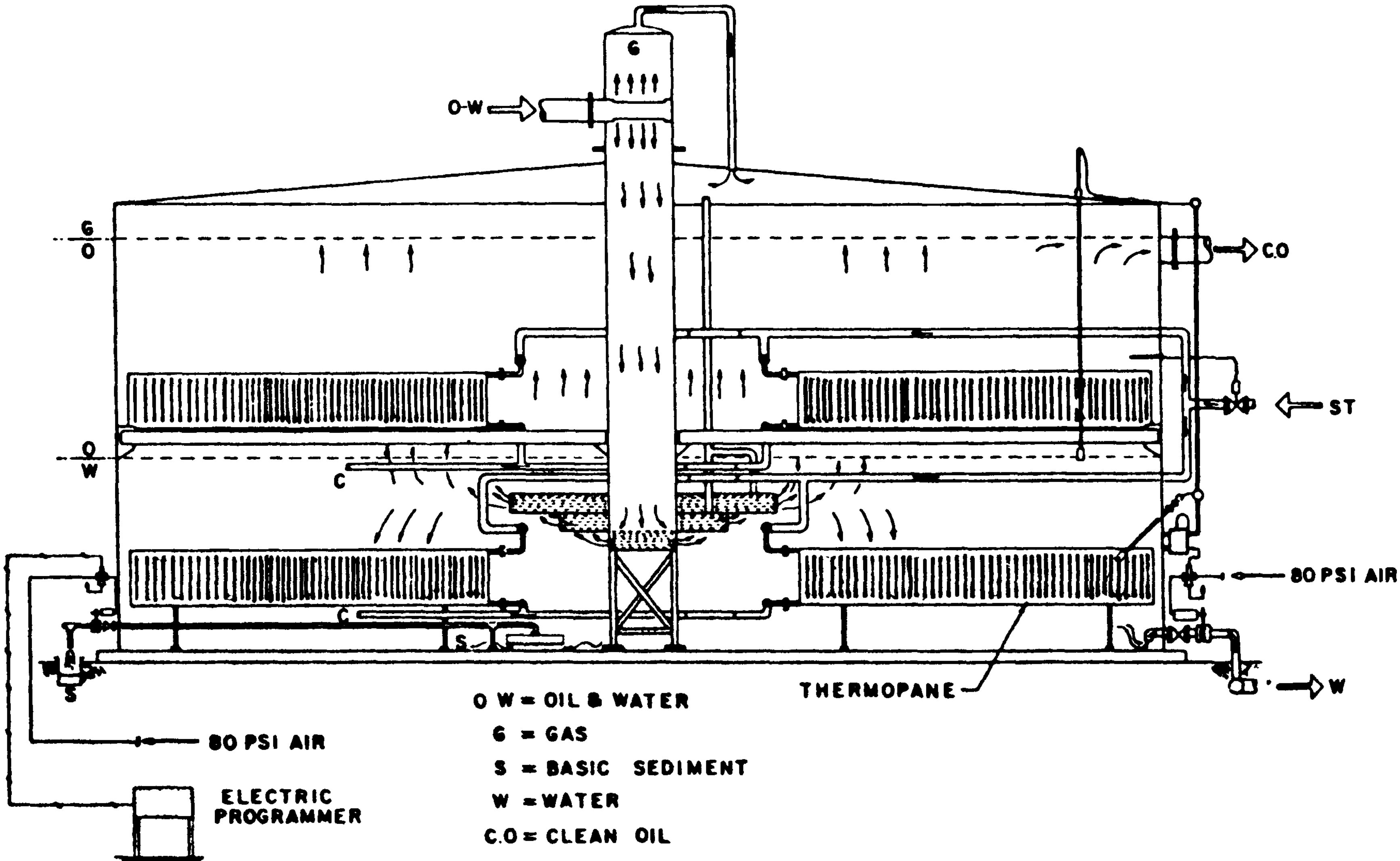


Fig. 4.1: AUTOMATETED WASH TANK (Ref. 89)

The horizontal heater treater (Figs. 4.2 and 4.3) is designed for treating heavy-duty emulsions of low gravity oil. The vertical heaters of the design shown in Fig. 4.4 have been most successfully employed with the higher-gravity crudes.

4.2.2 Electrical Dehydration

The operation of electrical dehydrators is based on the well-known principle of Cottrel. The oil-water emulsion is heated to reduct viscosity and is then exposed to a high-voltage alternating current field. Because water particles are charged, the alternating electric field increases the random motion or displacement and aids coalescence of the particles. Gravity separation occurs when the water particples coalesce into drops. Cleaning costs are usually greater with this type of equipment than they are with the gravity settling type.

4.2.3 Chemical Dehydration

The problem of resolving oil emulsions by the chemical demulsification process is by far the most widely used method. The scientific basis for the chemical resolution phenomenon is not yet well defined. Accordingly, much of the procedure employed has had to be developed empirically. This is because there are a great many possible combinations due to the variations in crude oil composition, aqueous phase composition, and the phase-volume ratio of the two liquids in any emulsion. In the pilot under consideration, the presence of foamer solution may cause further emulsion problems.

A large number of chemical reagents, mostly organic in nature, are available for resolving petroleum emulsions. To determine which class of reagent is the most effective in a particular application, one needs to know the type of crude and the conditions of production. Reagent selection is ordinarily accomplished by actual demulsification tests on a sample of the emulsion. Although the variable nature of crude oil emulsions and the specific demulsifier may seem to make the operation a highly individual matter, the operating steps of the procedure are the same. Emulsion and reagent are thoroughly mixed. Thereafter, quiescent standing permits the separation of the formerly-emulsified water. The usual practice is to employ a continuous process (flow-line treatment)

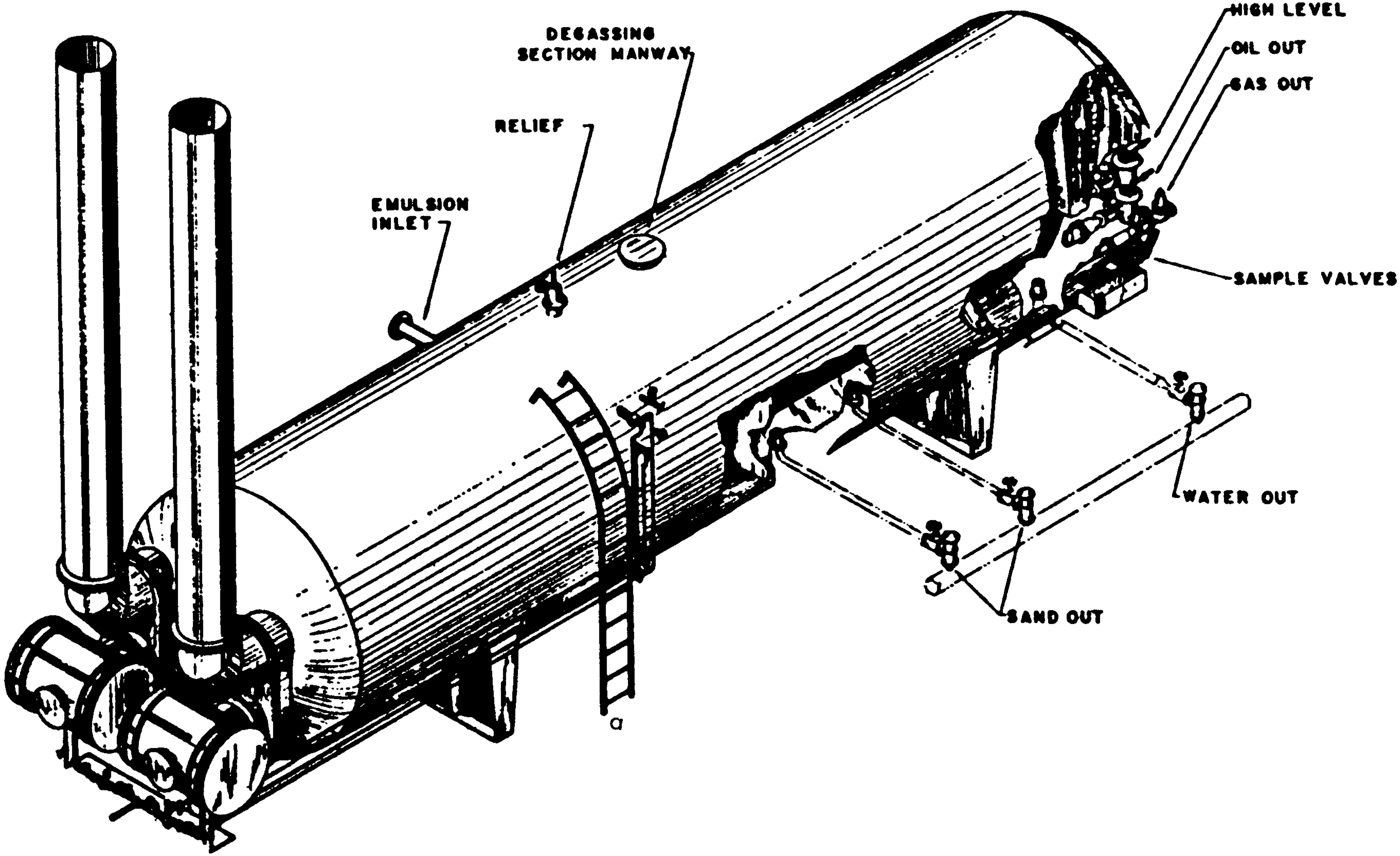


Fig. 4.2: PIPING HOOK-UP FOR HEATER TREATER (Ref. 89)

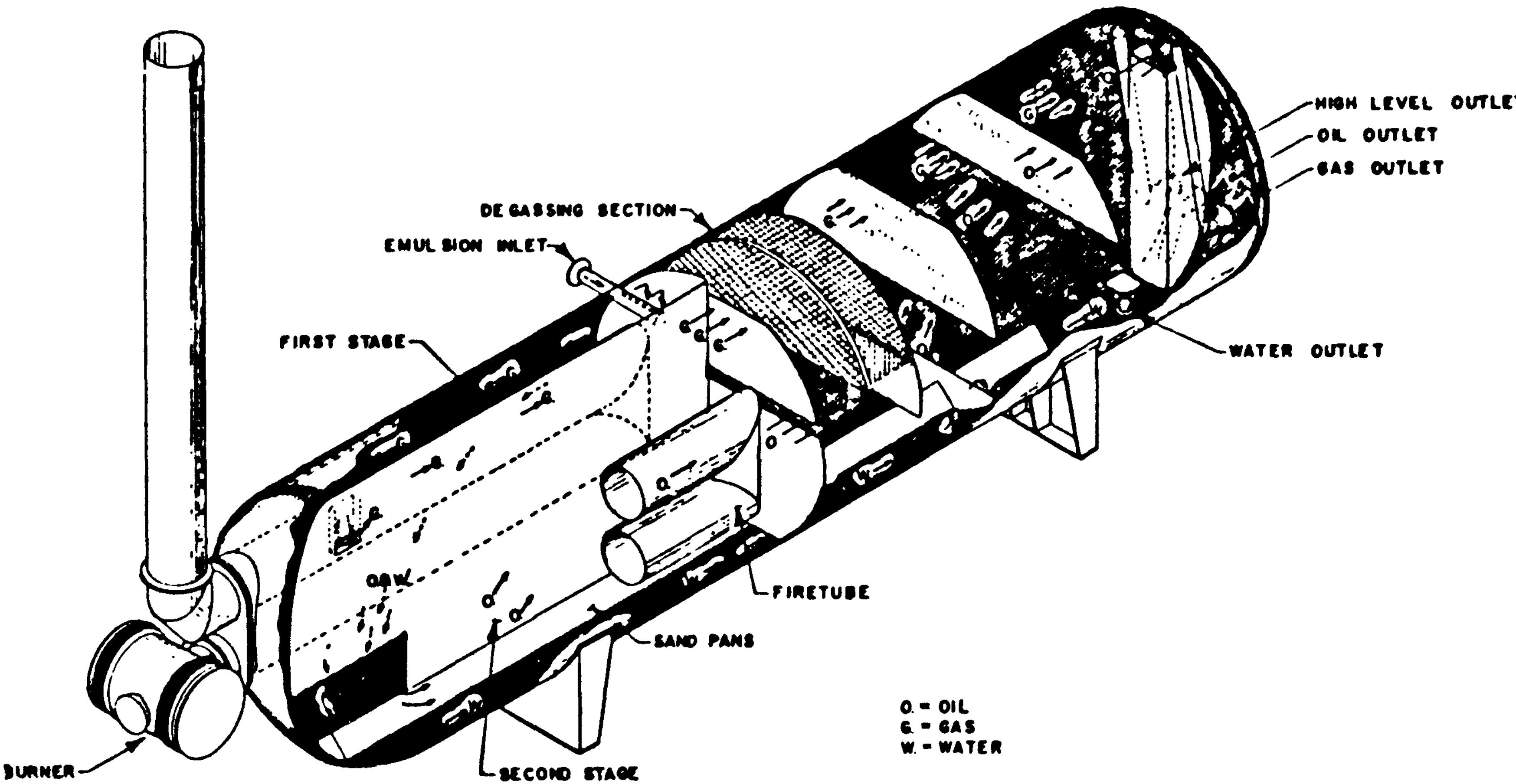


Fig. 4.3: SUPERIOR HORIZONTAL DOWNFLOW EMULSION HEATER TREATER (Ref. 89)

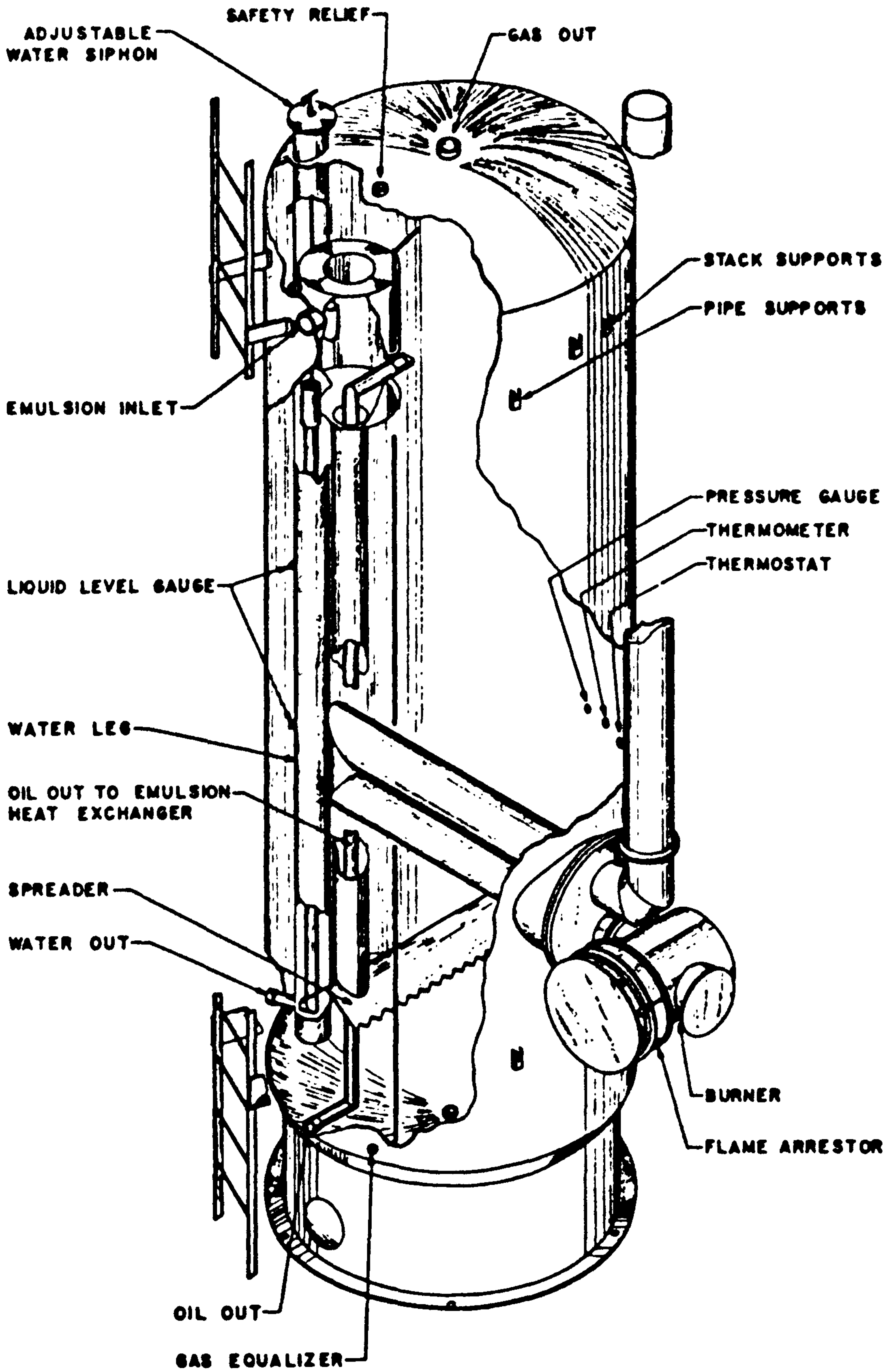


Fig. 4.4: SUPERIOR VERTICAL EMULSION HEATER TREATER (Ref. 89)

which introduces the reagent continuously into the emulsion at the well-heat or at some point in the flowline or even into the well, heating the mixture during the passage through the flowline if required, and then settling the water in a settling tank (see Fig. 4.5). In the continuous treatment, the demulsifier is usually injected near the wellhead to take advantage of the natural heat and of the turbulence in the system. The cost of demulsification is included in the estimates of the operating and maintenance cost of the pilot.

Storage tanks: Small storage tanks up to 500 bbl capacity would be adequate for this pilot. Bolted tanks have the advantage of ease of transportation and relocation and are therefore suitable for this pilot test. API specifications 12B, 12C, 12D and 12F cover bolted and welded steel tanks, whereas 12G covered welded aluminum tanks.

4.3 ACCESSORY EQUIPMENT

This includes the equipment that is not basically necessary for conveying oil from the wellhead to the pipeline or for other transportation. Vapor recovery, waste water disposal, and automatic custody transfer are included in this group. A vapor recovery unit is not needed in the production of heavy oil, where the gas/oil ratio is usually zero. Waste water disposal is discussed as part of environmental considerations in Section 6.

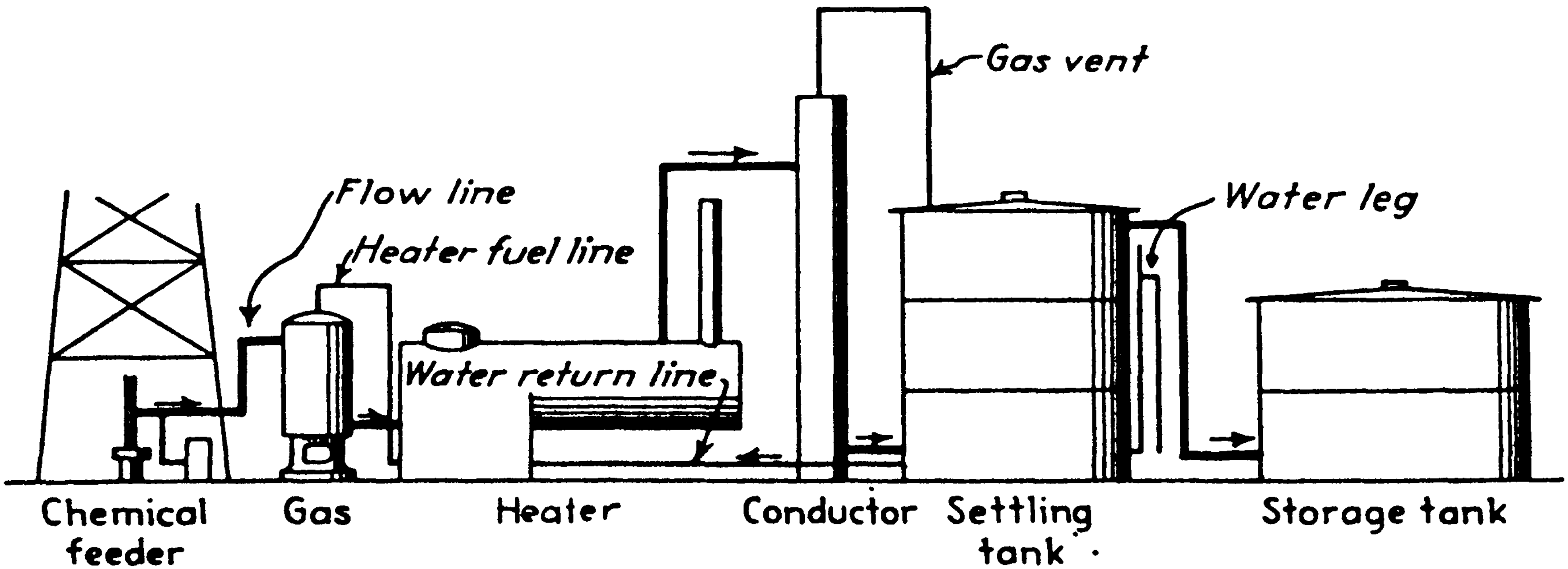


Fig. 4.5: CONTINUOUS DEMULSIFICATION PROCESS (Ref. 73)

5. LABORATORY RESEARCH, FORMATION EVALUATION AND RESERVOIR ENGINEERING

It is necessary that the laboratory research and the field test are properly coordinated such that a maximum amount of information about the process can be obtained within the available time and budget.

5.1 LABORATORY RESEARCH

During the design of the pilot, a number of laboratory experiments will need to be performed in order to obtain data on the characteristics of the surfactant to be used. The main experiments are concerned with:

1) Foamability and chemical stability of the surfactant at elevated temperatures;
2) The optimum concentration of the surfactant;
3) Possible use of co-surfactants;
4) Effectiveness of the surfactant in reducing gravity override and channeling;
5) The optimum slug size;
6) Loss of surfactant by adsorption on rock;
7) Partitioning of surfactant between the oil and water phases;
8) Any special emulsion problem; and
9) Longevity of the surfactant at the steam injection condition.

Many of these experiments have already been conducted at SUPRI. To date, three foamers, namely Suntech IV, Thermophoam BWD and Corco-180, have proved promising for in-situ foaming during steam drive. However, once a surfactant is chosen, all the characteristics listed above have to be determined in order to optimize the surfactant use in the pilot. The formation evaluation and reservoir engineering effort associated with a pilot can be divided into three phases:

1) Reservoir definition and performance forecasting by well logging, coring, transient well testing, injectivity testing, and reservoir simulation;

2) Reservoir monitoring and performance matching by logging observation wells, tracer response analysis, transient well testing, analysis of produced fluids, and reservoir simultion; and
3) Post-pilot study by drilling of post-pilot core holes with associated core analysis, logging and reservoir simulation.

5.2 RESERVOIR DEFINITION

Here, the objective is to determine reservoir properties, primarily the reservoir heterogeneity and the volume of recoverable hydrocarbons in each zone. Well logging is done to estimate porosity, permeability, lithology, saturations or reservoir fluids, and depth, thickness and areal continuity of the productive zones. The productive zone may be cored to obtain fluid saturations, permeability, porosity, etc. Core analysis results are compared with log data to supplement the latter. This may be followed by transient well testing to determine the continuity of the reservoir, permeability, well damage, directional permeability, if any, total compressibility, etc. Finally, the injectivity profile in the injection well must be determined by one of several injectivity logs--spinner log, temperature log, tracer log, etc.

5.2.1 Well Logging

Standard suites of open and cased-hole logs as shown in Tables 5.1 and 5.2 respectively, are usually run in such a pilot. Parameters estimated by each log and the costs in 1980 dollars (for a 1000 ft well in Kern County) are also shown.

Reservoir properties such as porosity, permeability, and saturations of the reservoir fluids can be measured directly from cores. The depths and thicknesses of pay zones can be better determined by well logging supplemented by coring. Such properties can be obtained from cores by conventional core analysis. For very accurate core analysis, the degree of mud invasion can be determined by drilling down to the top of the productive interval using conventional clay mud, then circulating a drift-pack mud system with polymers to get necessary viscosity and then diluting with 5% methanol.[84] The presence of methanol in the core gives the extent of mud invasion. Special core analysis can be done by flooding the core with steam or surfactant[85] to obtain residual oil saturations.

TABLE 5.1

OPEN HOLE LOGS

(All costs in 1980 dollars)

LOG	PARAMETER ESTIMATED	COST
Dual Induction Focused (with SP)	Saturations	$1180
Borehold Compensated Sonic (with caliper and SP)	Porosity & Lithology	$1240
Compensated Formations Density (with caliper and gamma ray)	Porosity & Lithology	$1240
Compensated Neutron (with gamma ray)	" "	$1240
Gamma Ray	" "	$ 320
Dielectric Constant	Saturations	$1360

These logs will be run in all production, injection & observation wells including post-pilot core holes.

TABLE 5.2

CASED HOLE LOGS

(All costs in 1980 dollars)

LOG	PARAMETER ESTIMATED	COST
Pulsed Neutron (with gamma ray)	Saturations	$1240
Carbon-Oxygen	Saturations	$1930
Dielectric Constant	Saturations	$1360
Cement Bond (with full-wave-train display)	Cement effectiveness	$ 920

These logs will be run in injection and observations wells.

5.2.2 Coring

Cores can be taken either as whole core or sidewall samples. For the Kern River area, whole cores are preferable because the formation is unconsolidated. However, even whole cores are also difficult to obtain in such an unconsolidated formation. In order to avoid reservoir fluid losses from the core sample during recovery and handling, pressure-coring is sometimes used. In this method, the core is taken from the formation in a pressurized chamber and frozen at the site. This is a very expensive method. A less expensive alternative to pressure-coring is to drill a 5.25-in. core instead of 3.25-in., with reduced mud circulation and recover the core sample in a plastic sleeve.[84]

5.2.3 Transient Well-Testing

In order to obtain important reservoir parameters, pressure buildup and drawdown testing on each well, as well as interference and pulse testing between wells can be performed. There is an economic advantage to drawdown testing since the well produces during the test. The major disadvantage is the difficulty of maintaining a constant production rate. By standard analysis of drawdown and buildup test data, one can calculate some reservoir properties within the drainage area of the well.

A typical pulse test for this pilot may consist of intermittently pulsing the injector and monitoring the response in off-set wells. Well I_s may serve as an injector. Wells S_1, S_2, S_3 and S_4 may serve as the observation wells (Fig. 5.1). The wells will be completed in the same

STEAM INJECTION				IN-SITU FOAMING WITH STEAM		
S_1 0		S_2 0		F_1 0		F_2 0
	0I_s				0I_f	
0 S_3		0 S_4		0 F_3		0 F_4

Fig. 5.1: PROPOSED FIVE-SPOTS

zone. Multi-well analysis yields values of reservoir properties that best represent the section. This approach is superior to well-pair analysis for providing average values of reservoir properties because a larger sample of reservoir is represented. The observation wells may be equipped with Hewlett-Packard 2811 quartz-pressure gauges run in the tubing and lined up opposite the zone under test. The injection well may be equipped with a pressure transducer at the wellhead and a strip chart recorder for continuous measurement. The pulse test in Well I_s should use four cycles of injection rates, 100, 200, 400 and 800 barrels per day, followed by shutting in the well. These rates can be measured with a recording orifice meter and controlled initially by a choke and later by a spring-loaded adjustable flow regulator. The magnitude of the initial response and the response time recorded in the observation wells indicate continuity between the wells. Pressure build-up data may be recorded in the injector for each rate change during the test. These data, coupled with the pressure falloff tests should provide reservoir permeability.

In the second phase of transient well testing, interference tests may be performed. The injection rate may be 48 hours at the rate of 400 barrels per day followed by a shut-in period of 96 hours. Pressure data may be recorded at least once every hour for the observation wells. This test may be used to verify the first test.

5.2.4 Injectivity Test

Injectivity profiling may be done by Gamma Ray (Tracer Ejector) Log. This evaluation is generally made by ejecting a liquid tracer material from the logging tool and observing the movement of the radioactive slug. By timing the departure of these slugs from the ejector to their arrival at the radiation detector placed above or below in the wellbore, a flow log is computed, indicating the rate of travel of the wellbore fluids at various levels. A temperature log or spinner log may also be used as a supplement to the tracer log. All of the above-mentioned tests may be done on both the five-spots separately.

5.3 RESERVOIR MONITORING

In this phase, the testing is carried out during the production of the reservoir, to check areal sweep efficiencies, vertical conformance of the displacing front, gravity segregation, changes in fluid saturations, etc. Here, the performance of steam drive with in-situ foaming will be compared with that of ordinary steam drive.

The following formation evaluation and reservoir engineering techniques may be employed for both the five-spots.

5.3.1 Logging of Observation Wells

Observation wells are logged to observe changes in reservoir fluid saturations and to monitor flood fronts. The temperature log will give an indication of hot water or steam flow in the reservoir. Suitable logs (as shown in Table 5.3) may be run to find changes in saturations. Parameters estimated by each log with its maximum temperature limit are also mentioned. The cost of running each log has been mentioned in the Reservoir Definition section. Temperature logs may be run every month while other logs may be run every three-to-four months or as needed. Before running a log in the observation well, it should be made sure that the temperature of the well does not exceed the maximum temperature rating of the log.

5.3.2 Tracer Response Analysis

In order to analyze the areal sweep efficiencies and the vertical conformance of the displacing front, a radioactive tracer such as

TABLE 5.3

OBSERVATION WELL LOGS

LOG	PARAMETER ESTIMATED	MAX. TEMP.
Temperature Log	Reservoir Temp. (Hot water/steam)	400°F
Carbon/Oxygen	Oil & Water Sat.	270°F
Pulsed Neutron	Oil, Gas & Water Sat.	350°F
Cement Bond	Cement Effectiveness	500°F

tritiated water may be used. Most non-radioactive tracers will not be as useful as tritium because of their low volatility and, hence, absence in steam. The tracer may be injected before, during, or after the injection of the surfactant. Samples of the fluid from the producing wells should be analyzed to determine the concentration of a radioactive material. These results can be mathematically analyzed to understand reservoir characteristics.

5.3.3 Transient Well-Test Analysis

Determination of the steam-swept volume in a steam-drive project is of primary concern. Estimation of swept volume is possible by the method proposed by Satman, et al.[86] which uses the transient pressure data taken from injection wells. This method is based on the concepts of pseudo-steady state and material balance. Bottomhole pressure from the injection well is plotted against the shut-in time on a Cartesian graph. By material balance, the pore volume swept by the front is equal to the steam injection rate divided by the mean compressibility of the steam in the swept zone multiplied by the rate of pressure change during pseudo-steady state indicated on the graph. Thus, if porosity is known, it is possible to estimate the bulk volume swept by the front. An estimate of the swept volume would allow an estimate of the heat loss from the steam zone. The common transient pressure tests mentioned in the Reservoir Definition section may also be repeated here. In reservoir monitoring, the emphasis is on the estimation of reservoir parameters which may change with the production of oil such as: skin and storage effects, steam-swept volume, total compressibility, flow efficiency, etc.

5.3.4 Analysis of Produced Fluids

In order to assess the performance of the pilot, it is necessary to record the volumes of total fluids produced, gas/oil ratio, oil/water ratio, density and viscosity of oil, composition of the casing gas, etc. This information can be obtained by the use of a well-testing unit connected to the producing well.

5.3.5 Reservoir Simulation

Information obtained from the formation evaluation and reservoir engineering techniques can be used to develop a mathematical model of the reservoir. This model can then be used to simulate reservoir performance which can be matched with the actual production history of the pilot. If the reservoir model is correct, the simulated and actual behavior of the reservoir should match. If not, the model is modified repeatedly until such a match is obtained. The mathematical simulation studies applicable to such a pilot may be divided into three parts:

1) Tracer test performance matching;
2) Pattern balance; and
3) Reservoir predictions.

Tracer Test Performance Matching: An analysis of the tracer response helps provide an adequate description of the reservoir for the design and analysis of the pilot. Detailed history matching of the tracer response at a well should provide the information concerning the longitudinal dispersion and the vertical distribution of permeability.

Pattern Balance: Mathematical models are available to estimate the effect on the drainage pattern of the pumping rate at any well. Iso-potential maps constructed from the simulation results can help in obtaining the balance between the drainage areas of the individual wells in a pattern.

Reservoir Predictions: Reservoir volume-swept can be simulated with changes in steam injection rates by using the method of Marx and Langenheim.[88] Information obtained from coring, logging, well testing and materials balance may be used to develop a numerical model of the reservoir to predict recovery efficiency.

5.4 POST-PILOT STUDY

This study will be the last phase of the pilot test. After the steam injection is stopped, the following may be employed to get information about the post-production reservoir condition.

5.4.1 Coring

Post-pilot core holes are to be drilled and analyzed for the post-injection reservoir condition. Conventional core analysis may be done on samples taken from the productive zone. Well logging of these holes will provide a better insight into the vertical distribution of the post-pilot reservoir characteristics.

5.4.2 Simulation

Simulation techniques that were employed in reservoir monitoring could be extended further in establishing expected recovery efficiencies of the two five-spot patterns of this pilot test. The actual recovery efficiency achieved (as determined from coring, logging, well testing and materials balance) may be compared to the expected recovery efficiency.

By the conclusion of post-pilot study, the performance of steam drive with in-situ foaming would be compared to that of the plain steam drive. Economic and technical feasibility of in-situ foaming can then be established. The decision to expand the operation to field size should be based on the results of such a pilot.

6. ENVIRONMENTAL CONSIDERATIONS

6.1 CAUSES OF ENVIRONMENTAL EFFECTS

The following elements are processes that are common to all enhanced oil recovery (EOR) methods: a recovery fluid, an injection system, surface processsing, and disposal of spent materials.

The processes and the materials used within the confines of the system pose no environmental threat. Environmental problems results only when the materials are allowed to escape. The following mechanisms be responsible for such an escape:[21]

1) Transit spills--spills which may occur when material is being prepared at, or transported to, the field site.
2) On-site spills--spills which may occur at the field site from surface lines and/or storage facilities.
3) Well system failure--escape of materials which may occur from failure of injection or production well due to casing leaks or channeling.
4) Fluid migration from reservoir--fluid may migrate outside of the confining limits of a reservoir through fractures or through a well bore outside the pilot project area which interconnects reservoirs.
5) Operations--the effects caused by routine activities and by the support facilities and activities associated with EOR production.

To determine environmental problems during operations, the effect of each of the following must be considered: disposal of spent material, comsumption of site-associated natural resources, discharge emissions, leak emissions, and support efforts.

6.2 AIR QUALITY IMPACT

While all EOR methods can cause air pollution, thermal methods are most likely to cause this kind of problem. Steam generators usually use the fuel supply available on location (crude oil being the most common

Table 6.1

EMISSION FACTORS FOR FUEL OIL COMBUSTION (Ref. 21)
(Pounds Emitted per 1,000 Gallons Burned)

Pollutants	Power Plant	Residual Oil	Domestic Sources
Aldehydes	1	1	2
Hydrocarbons	2	3	3
CO	3	4	5
NO_x (as NO_2)	105	40-80	12
SO_2	157 S^*	157 S^*	142 S^*
Particulates	8	23	10

S^* = Percent fulfur in oil

Table 6.2

STEAM GENERATOR EMISSIONS (Ref. 21)*
(Pollutants Emitted per 1,000 Barrels of Gross Oil Produced)

Hydrocarbons	40 lbs
SO_2	4,000 lbs
NO_x	800 lbs
Particulates	280 lbs

* For crude containing 2% sulfur, without flue gas desulfurization.

NOTE: This table assumes that 0.3 barrel of fuel oil is burned for every 1.0 barrel of gross production. Due to a shortage of data, fugitive emissions are excluded for the analysis.

fuel source), and emit sulfur dioxide (SO_2), oxides of nitrogen (NO_x), hydrocarbons, carbon monoxide (CO), carbon dioxide (CO_2), and other combustion products from the exhaust pipes. This aspect of the environmental impact of thermal EOR activities is likely to be localized, but may become serious depending on the topography and weather characteristics. Estimates of levels of air pollution from the steam flooding process can be made if both the amount of fuel to be burned and the emissions per unit volume of the fuel burned are known.

Emission factors[21] are shown on Table 6.1. Steam generator emission in pounds emitted per 1,000 barrels of oil produced can be calculated[21] from Table 6.1 using the values given for residual oil. The results of this calculation are given in Table 6.2. Estimates in Table 6.2 are based on the consumption of 0.3 barrels for every 1.0 barrel of gross production. This level of consumption approximates commercial-scale steam generator operations in the San Joaquin Valley in California. The emission factors presented in Table 6.2 are just estimates and do not necessarily portray accurate emissions of in-field EOR steam generators. The steam drive process is an energy-intensive operation that entails the consumption of one-quarter to one-half of the oil produced.[22] In absolute terms, about 200 to 300 barrels of oil per acre foot of reservoir must be burned to generate the required steam to carry out the process and recover 40% to 50% of the oil in place.

Based on a 1977 California Department of Conservation report, the San Joaquin Valley Air Basin accounted for approximately 80% of the total thermal EOR operations in California. Of this portion, 99% of the thermal EOR operations occur in Kern County. As of early 1979, there were about 940 steam injection wells operating in Kern County. These wells utilize saturated steam with a "quality" of about 80%. The steam is generated by burning a portion of the crude oil produced. Most of the units have output capacities of about 20 million or 50 million BTU/hr.

The 1978 annual average SO_2 concentration at one Kern County monitoring station as 87 $\mu g/m^3$. Directly emitted particulate matter and SO_2 emissions from steam generators both contribute to the violation of state and federal ambient air quality standards for total suspended particulates.

New regulations were imposed in late September 1979 which apply to those units with heat input equal to at least 15 million BTU/hr.

The emission limitations are as follows:

*	New Sources (Permit to construct on or after 2/21/79)	0.06 lb sulfur/million BTU (about 0.12 ob SO_2/million BTU input)
*	Existing Sources (Permit to construct prior to 2/21/79)	By July 1, 1982, 0.25 lb sulfur/million BTU input (about 0.50 lb SO_2/million BTU input)
		By July 1, 1984, 0.12 lb sulfur/million BTU input (about 0.24 lb SO_2/million BTU input)

For the typical crude oil fired (Higher Heating Value = 146,500 BTU/gal; sulfur content = 1.15%), this regulation will require about 90% SO_2 removal for a new steam generator. There is well-proven technology available to attain the required control levels. The simplest proven systems are sodium hydroxide or sodium carbonate as the make-up reagent; the bleed steam from such an absorber recirculation is discarded. There are many such flue gas desulfurization (FGD) systems already operating at California thermal EOR sites.

By June 1979 there were 13 oil companies (at 17 sites) using or planning to use FGD systems. At 11 of the sites, there were a total of 84 separate FGD systems controlling 174 generators.

Table 6.3 is a summary of the level of FGD activity at thermal EOR (TEOR) sites in California. For each company engaged in such activity, the table presents fuel oil sulfur percent, SO_2 thermal efficiency, FGD system supplier, number of FGD units, generator capacity, and the operational status.

The following subsections briefly describe the 7 flue gas desulfurization processes.

6.2.1 Ammonia Scrubbing Process

The ammonia process utilizes ammoniacal liquor for SO_2 absorption. The basic reaction in the scrubbing tower is the following:

$$NH_3 + H_2O \quad = \quad NH_4OH$$

$$NH_4OH + NH_3 + 2SO_2 \quad = \quad (NH_4)_2S_2O_3$$

TABLE 6.3

FGD APPLICATIONS AT CALIFORNIA TEOR SITES (AS OF JUNE 1979) (Ref. 20)

Company	Location	Fuel Oil percent S	SO_2 Removal, %	FGD System Supplier	No. of FGD Units	Total Generator Capacity Under Control (10^6 Btu/hr)	FGD Status*
Belridge Oil	McKittrick	1.1	90	C-E Natco	1	50	0
			90	Heater Technology	1	50	0
			90	Thermotics	1	50	0
Chevron USA	Bakersfield	1.1	90	Koch	5	900	0
Double Barrel Oil	Bakersfield	1.1	95	C-E Natco	1	50	0
Getty Oil	Bakerfield	1.1	96	In-house	9	4050	0
			90+	FMC Environmental	1	300	0
	Orcutt	4.0	94	In-house	1	22	0
Grace Petroleum	San Luis Obispo	1.3	95	Thermotics	2	100	0
			95	Thermotics	2	100	C
Mobil Oil	Buttonwillow	1.1	85	Heater Technology	7	350	C
	San Ardo	2.0-2.25	90	In-house	28	800	0
PetroLewis	Bakersfield	1.08	95	Thermotics	1	50	0
Rainbow Oil	Bakersfield	1.1	90	Thermotics	1	18	C
Santa Fe Energy	Bakersfield	1.5	96	FMC Environmental	1	310	C
Shell	Bakersfield	1.1	94	Not selected	1	400	P
	Taft	1.1	94	Not selected	1	100	P
Sun Production	Fellows	1.4	85	C-E Natco	1	25	C
	Oildale	1.2	85	C-E Natco	1	25	C
Texaco	San Ardo	1.7	95	Ducon	3	450	C
			73	Ceilcote	29	1560	0
Union Oil	Guadalupe	3.0	90	Heater Technology	2	50	0
			90	Koch	1	25	0
			90	Thermotics	1	25	0

*Status code, 0 = operational, C = construction, P = planned, considering SO_2 control

$$NH_4OH + SO_2 = NH_4HSO_3$$

The flue gas from the steam generator enters a quencher section by means of a forced draft fan, in which the gas is cooled to its adiabatic saturation temperature by recirculating water. The flue gas is further scrubbed in a recycle. The spent sulfite from the scrubber is filtered to remove sludge and the filtered liquor autoclaved at 200 psi and 350°F for 3 hours to produce ammonium sulfate and elemental sulfur:

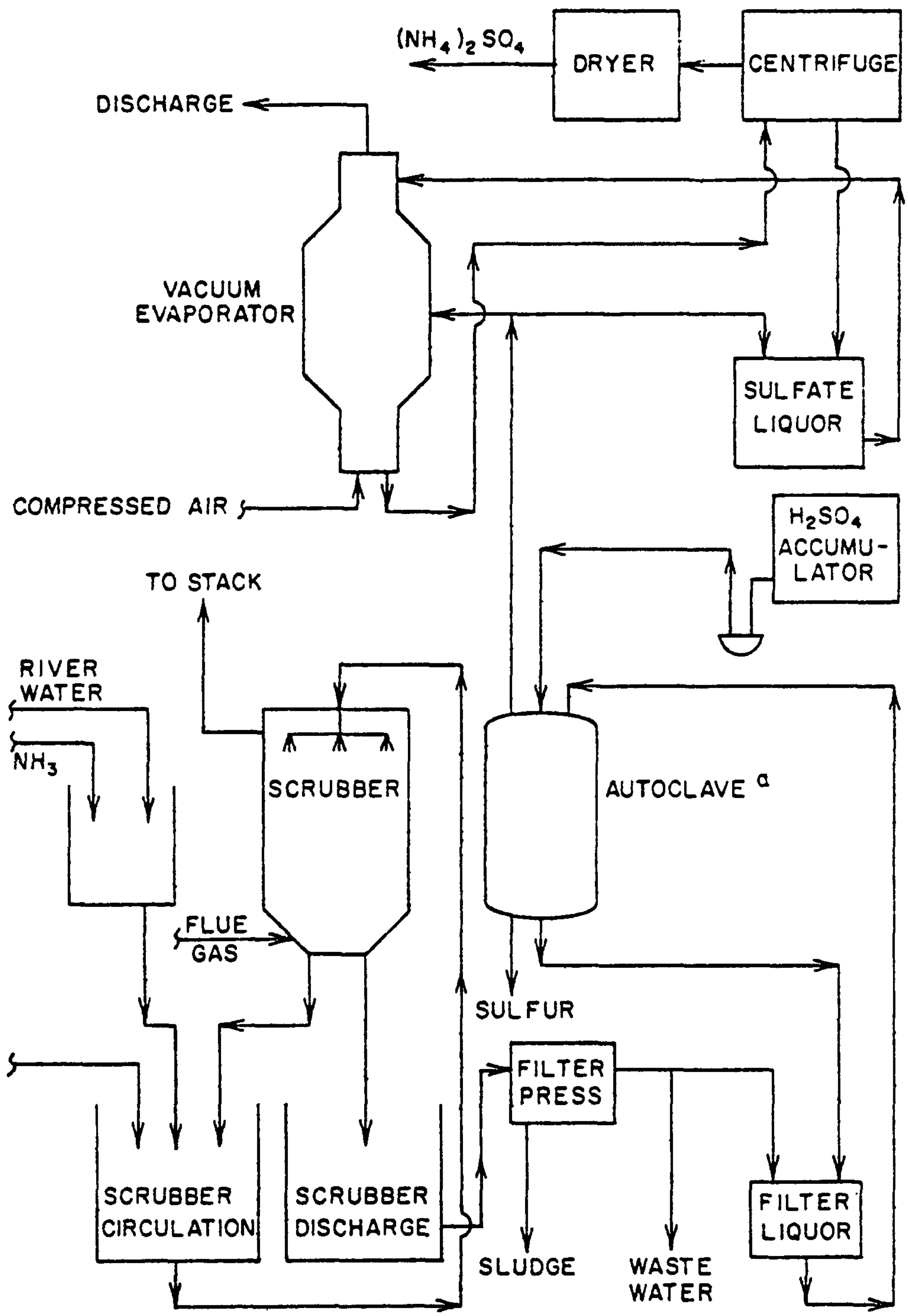
$$2NH_4HSO_3 + (NH_4)_2S_2O_3 \rightarrow 2(NH_4)_2SO_4 + 2S + H_2O$$

The process is also described in Fig. 6.1. The byproduct solution would contain 20 to 24 percent by weight ammonium sulfite. If this product meets the standards of purity, it may then be possible to market it as a fertilizer.

Compatibility with NO_x Removal System. The ammonia-based process has the advantage of being amenable to combination with NO_x control by selective catalytic reduction (SCR). An SCR unit preceding the SO_2 absorber could be designed to inject excess ammonia (the SCR unit and associated capital cost would therefore be smaller), and the excess ammonia would be picked up in the absorber. This amount could be considered as partial reagent make-up for SO_2 removal.

6.2.2 Carbon Adsorption (Foster-Wheeler/Bergbau Foshcung) Process

This process is comprised of three sections: adsorption, regeneration and sulfur production. In the adsorbtion section, the partially quenched flue gas containing sulfur oxides, nitrogen oxides, oxygen, water vapor and some particulate matter comes in contact with activated carbon pellets (char) of the crossflow absorber. The flue gas passes horizontally through a bed of char which moves downward and becomes increasingly saturated. Surfur dioxide, oxygen, and water vapor are adsorbed on the char. The regeneration of char is accomplished by heating the char in an inert atmosphere to temperatures in excess of 1250°F. Under these conditions, the sulfuric acid is regenerated. A simplified flow diagram is shown in Fig. 6.2.



[a] AN AUTOCLAVE IS A PRESSURIZED VESSEL WHICH SUBJECTS MATERIAL TO SUPERHEATED STEAM, IN THIS PARTICULAR CASE 170°C AT 200 PSI.

Fig. 6.1: FULHAM-SIMON CARVES AMMONIA SCRUBBER (REf. 24)

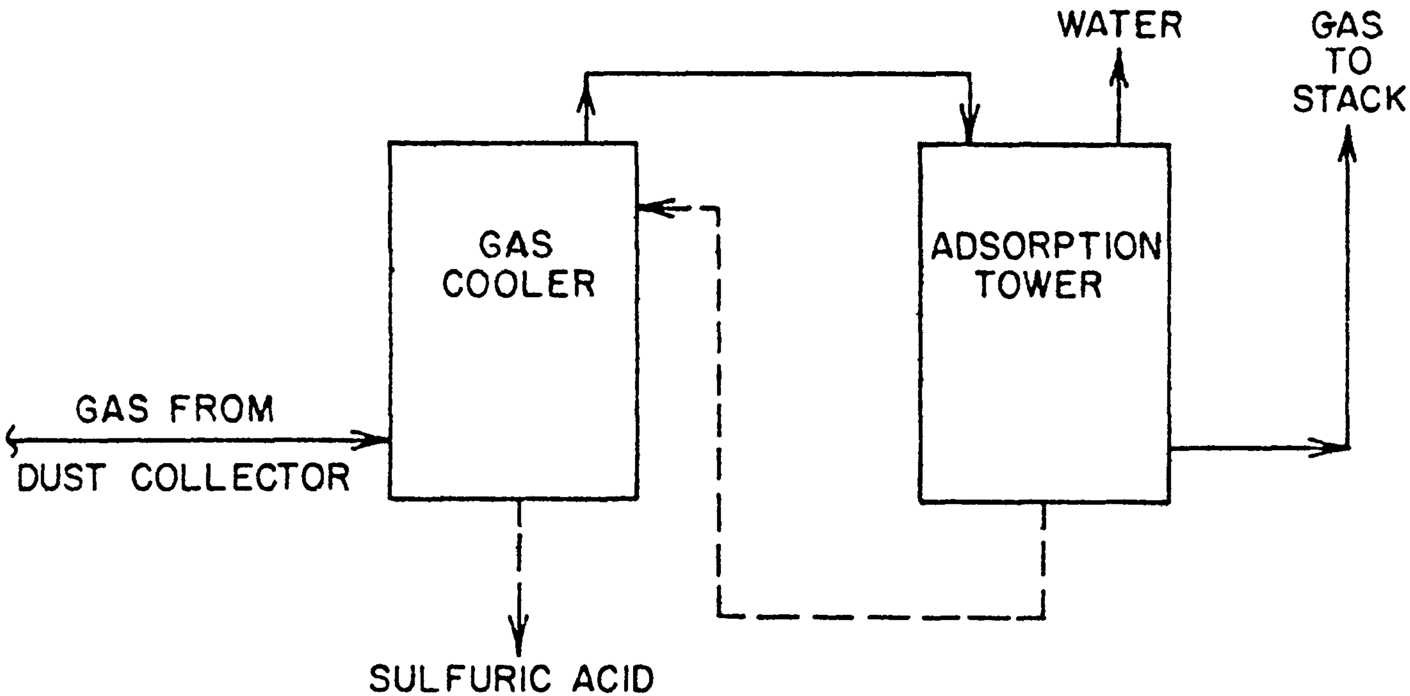


Fig. 6.2: SIMPLIFIED SCHEMATIC FOR CARBON ADSORPTION PROCESS (Ref. 24)

6.2.3 Copper Oxide Sorption Process

The copper oxide process consists of the following sections: reaction, quenching, reforming and cleaning unit. The flue gas, through a forced draft fan, enters one of the two parallel passages, fixed bed reactors containing copper on aluminum oxide support.

The two reactions operate in a swing model of SO_2 adsorption and adsorbent regeneration alternately. First, the reactor is purged of the gas, and then the regeneration gas is introduced. The gas contains a high amount of H_2 which reacts with $CuSO_4$ to recover the original Cu. The acceptance and regeneration reactions are exothermic and take place at the same temperature of 750°F.

Two-third of SO_2 is reduced to hydrogen sulfide. The remaining stream is heated and passed through a catalyst-packed converter where SO_2 and H_2S react to form elemental sulfur and water. The sulfur is sent to a sulfur pit for storage and recirculation. This process is very expensive and has high energy requirements.

6.2.4 Double Alkali Process

The double alkali process consists of SO_2 absorption, scrubbing liquor regeneration with simultaneous generation of calcium salts, solids dewatering and disposal.

The flue gas is cooled in a quencher to its dew point. A small stream is continuously bed from the quencher recycle loop to purge particulates and chlorides. Then in the absorber, alkaline solutions of sodium hydroxide and sodium sulfite have direct contact with the incoming flue gas to absorb SO_2 according to the following reactions:

$$2NaOH + SO_2 \rightleftarrows Na_2SO_3 + H_2O$$

$$Na_2SO_3 + H_2O \rightleftarrows 2NaHSO_3$$

The cleaned gas leaves the system through a stub stack.

The bleed-off stream from the absorber is reacted with lime in a tank. The soluble sodium species are regenerated by reaction with lime. The reactor effluent, then, is a mixture of soluble sodium species and insoluble calcium salts.

$$Ca(OH)_2 \; Na_2SO_3 \rightarrow 2NaOH + CaCO_3\downarrow$$

The insoluble salts are separated from regenerated liquor in a thickener and further concentrated in a rotary vacuum filter. The thickener overflow is pumped to a holding tank before being fed to the absorber. The filter cake generated is washed and the solution is pumped to the thickener. This process is also shown in Fig. 6.3.

In order to precipitate dissolved calcium and minimize the potential for deposition of calcium salts in the absorber, fresh soda ash is added to the thickener. This also serves to replenish sodium to the system.

The double alkali process has demonstrated SO_2 removal efficiencies well above 90%. The low liquid-to-gas ratio allows less change of entrained liquor in the flue gas.

6.2.5 Limestone Scrubbing Process (Conventional)

In the limestone process, the flue gas handled by a forced draft fan is passed through a quencher for adiabatic cooling to its dew point.

A small stream is bled from the quencher loop to purge particulates and chlorides. The gas then travels through a liquid-gas bowl separator (within the absorber module) which recycles the absorber slurry back to the absorber feed tank. A part of the slurry from the recirculation tank is added to the quencher. The gas passes through a small packed section with two spray levels, one above and one below the packed section. The absorbent, ground limestone, is stored in a silo and conveyed to the absorber recirculation tank by a screw conveyor. Service water is added to the tank and the fresh limestone is mixed with recycling liquor by two agitators. The bleed-off stream containing 6% solids is taken from the quencher loop to a hydroclone. The hydroclone overflow returns to the quencher while the underflow with 30% solids is dewatered to 60% solids in a vacuum filter. The filter cake is hauled to a sludge pond. A small amount of hydrated lime is added to the hydroclone underflow for stabilization of sludge. The entire process runs at a higher efficiency with maximum utilization by operating in a buffered region.

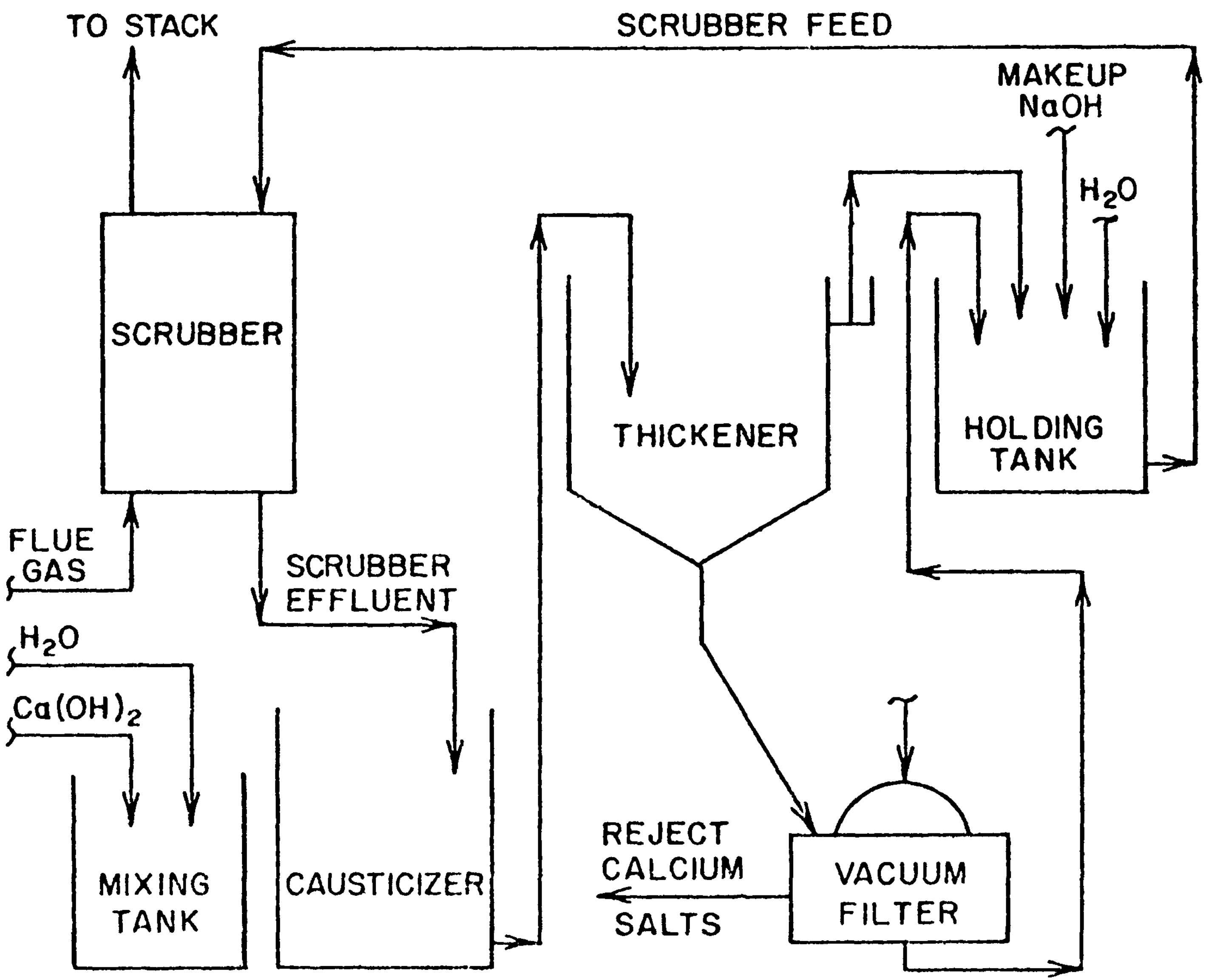


Fig. 6.3: SODIUM HYDROXIDE SCRUBBING WITH LIME REGENERATION (Ref. 24)

6.2.6 Sodium Sulfite Scrubbing (Wellman-Lord) Process

In the sodium sulfite process, the flue gas is handled by a forced draft fan and is humidified and cooled in a quencher. A small stream is continuously bed from the recirculation loop to purse the chlorides and particulates removed in the quencher.

The gas then passes up the absorber with trays, each of which has a separate recirculation loop. The SO_2 in the flue gas is absorbed in the recirculating sodium sulfite solution. A part of the bleed stream is disposed of after neutralization. The other part is mixed with a heated stream and taken to an evaporator/crysallizer. The vapors from the evaporator, containing SO_2 and H_2O, are sent through two condensers and a steam stripper. The concentrated liquor from the evaporator and the stripper bottoms are taken to a dilution tank. Fresh soda ash solution is added to the dilution tank and the regeneration lean solution is recycled to the top tray. This process is shown in Fig. 6.4. The SO_2 gas stream from the stripper can be concentrated and dried with silica gel and stored under pressure.

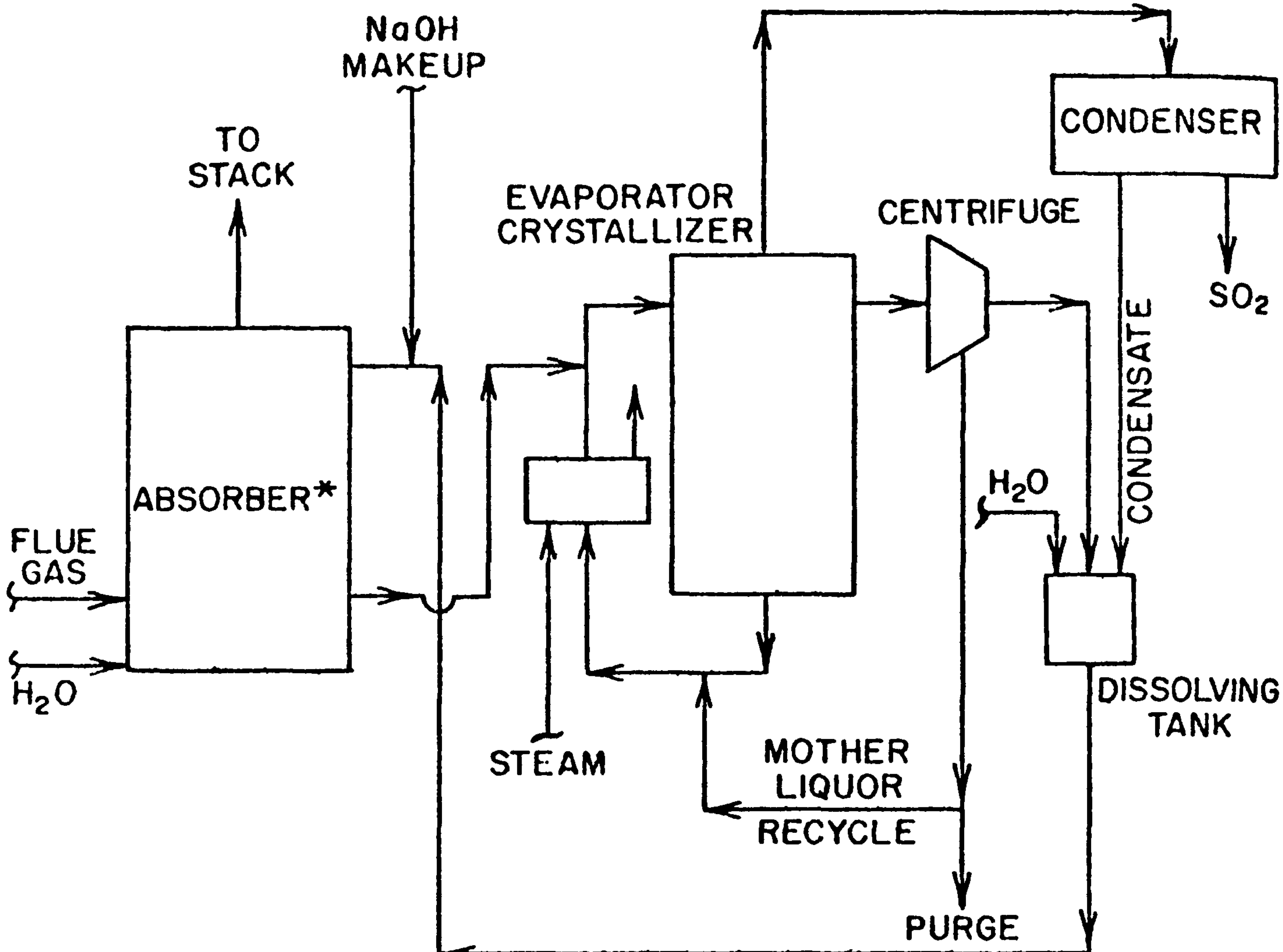
6.2.7 Sodium Carbonate Scrubbing Process

This is one of the most widely used processes at the thermal EOR sites. The flue gas is transported by a forced draft fan to a quencher where it is cooled to its dew point by recirculating liquor. A small bleed stream is continuously taken from the quencher loop to purge particulates and chlorides.

A fresh sodium carbonate solution (4% by weight) is prepared in a mix tank by addition of soda ash from a silo, and service water. The fresh solution is mixed with the recirculation liquor. The flue gas enters a four-stage tray absorber. The SO_2 is absorbed in a countercurrent mode by recirculation liquor added at the top of the absorber. The gas then passes through a Chevron-type mist eliminator which is washed intermittently by the service water and finally leaves the system through a stub stack. A constant bleed-off stream is taken to a bleed storage tank and pumped to a waste disposal site (Fig. 6.5).

6.3 PROCESS DESIGN

A larger number of Flue Gas Desulfurization (FGD) processes were assessed including the sodium-based processes currently being used in



* THE ABSORBER RECYCLE IS INTERNAL TO THE DISC-DONUT TYPE ABSORBER. THIS DISC-DONUT ARRANGEMENT, HOWEVER, HAS BEEN REPLACED BY THREE BEDS OF INTALOX SADDLES, IN THE UPPER SECTIONS OF THE TOP, MIDDLE AND BOTTOM STAGES, WHICH IMPROVES LIQUID-GAS CONTACT AND BRINGS FINAL SO_2 LEVELS TO 200 PPM.

Fig. 6.4: WELLMAN-LORD SULFUR DIOXIDE RECOVERY SYSTEM (Ref. 24)

California thermal EOR sites. Table 6.4 presents the comparison of 7 FGD processes with respect to advantages and disadvantages. All these FGD processes were compared at the common design basis as shown in Table 6.5. The reported capital costs for these thermal EOR FDG systems range from \$5/scfm* to \$21/scfm.

The most suitable flue gas desulfurization process for the pilot plant would be the sodium carbonate process. A scrubber compatible with a single 22-25 MM BTU/hr steam generator would cost \$115,000[74] with an additional \$15,000 for installation and freight.

6.4 OTHER ENVIRONMENTAL CONSIDERATIONS

6.4.1 Solid Waste Disposal

The disposal of solid waste generated by enhanced oil recovery will be regulated by the Resource Conservation and Recovery Act (RCRA). The Act provides for stringent storage, transportation and disposal requirements for any solid waste found to be hazardous under testing procedures and criteria defined in the regulations. The Act also establishes standards for the disposal of nonhazardous waste by landfill.

Scrubber sludges from steam generators used for EOR must be tested and, if found to be hazardous, must be handled according to the hazardous waste regulations. By the beginning of 1980 it was not as yet determined whether scrubber sludge will be declared hazardous; however, the presence of relatively high trace metals inthe California crude used in many thermal EOR operations increases the possibility that this scrubber sludge could be hazardous.

Oil and gas drilling muds, drilling foam and brines if found to be hazardous, are regulated as "special wastes" and subject to less stringent disposal requirements under the hazardous waste regulation proposed in December 1978, because of their large volume.

6.4.2 Waste Water Disposal

Federal Water Quality Administration (FWDA) gives the Administration enforcement power to control pollution of interstate water. Standard of

---

*scfm = Standard cubic foot per minute of flue gas volumetric flow.

Table 6.4

COMPARISON OF THE FGD PROCESSES

Advantages	Disadvantages
AMMONIA SCRUBBING	
Simultaneous SO_2/NO_2 removal, minimum cost, ease of handling Ammonia, no scaling, minimum corrosion and erosion.	Emission of blue fume is problematic. Fumine absorber with mist eliminator can handle only very low particulate matter. Fumeless absorber requires cooling below dew point.
CARBON ADSORPTION	
Dry Process, less expensive materials of construction. Potential for NO_x removal. On large scale by-product sulfur marketable.	Not yet commercially demonstrated. High capital cost. Energy intensive thermal regeneration. Loss of carbon.
COPPER OXIDE SORPTION	
Dry Process. On large scale by-product sulfur marketable. No waste disposal.	Not yet commercially demonstrated. Expensive material of construction, high reaction temperature.
DOUBLE ALKALI	
Eliminate liquid waste, requiring solid waste disposal. Inexpensive reagents costs.	Higher capital cost and higher maintenance requirements.
LIMESTONE SCRUBBING	
Least expensive source of alkali, relatively simple, more operating experience.	High corrosion and erosion large quantity of solid waste.
SODIUM SULPHITE	
Minimal waste product generated, low liquid-to-gas ratio in absorber.	High capital cost, higher maintenance cost, complex system.

(Continued on following page)

Table 6.4
(continued)

Advantages	Disadvantages
SODIUM CARBONATE	
High SO_2 removal, well established technology, many suppliers available. No plugging, low liquid-to-gas ratio. Suitable for pilot plant application.	Expensive reagent compared to limestone. Large waste disposal.

Table 6.5

DESIGN BASIS FOR A PROPOSED FGD SYSTEM IN A CALIFORNIA OILFIELD APPLICATION

Steam Generator Characteristics:	
Duty	25 million BTU/hr output
Steam rate	23,500 lb/hr, 80 percent quality
Excess air	12 percent
Load factor	90 percent
Fuel Oil Properties: (Typical heavy oil in California)	
Sulphur, wt percent	1.14
H.H.V. 146,500 BTU/gal	
Flue Gas Characteristics @ FGD System Inlet:	
Total flow rate	11,150 scfm @ 500°F
Molecular weight	29.05 (wet basis), 30.44 (dry basis)
Carbon dioxide, vol %	12.2
Water vapor, vol %	11.2
Oxygen, vol %	2.6
Sulphur dioxide	660 ppmv

Emission regulation:

0.06 lb sulfur/million BTU input, maximum (≃0.12 lb SO_2/million BUT input) stream water quality, established by the individual states and approved by FWQA, sets limits on the wastes discharged to a given water course.

The method chosen for disposal of waste water will depend to a great extent upon the size and location of the plant, the source, and the geology of the area. In Kern County, California, the two options of disposal are the Kern River and underground injection, after treatment.

Treatment of produced water is necessary before its disposal underground to prevent corrosion and clogging by deposits of oil or suspended solids, such as calcium carbonate. Hydrogen sulfide, a rather common and highly corrosive constituent of these waters, should be removed. Frequently, the release of pressure results in the release of some of the free carbon dioxide content, and this may result in precipitation of some of the calcium alkalinity. Treatment with small dosages of lime plus acid or acid alone may be used to prevent clogging with calcium carbonate. The removal of oil is usually accomplished by settling and oil skimming plus filtration. Chlorination may also be required to remove the last traces of hydrogen sulfide or to destroy micro-organisms such as the sulfate-reducing bacteria.

6.5 HEALTH AND SAFETY IMPACTS

Many of the health and safety hazards associated with EOR are similar to those in conventional oil recovery. These risks are associated with the operation of machinery, the handling of hazardous chemicals, exposure to the hydrocarbons found in crude oil, high occupational noise levels, and the possibility of blowout or fire which exist at any oil recovery operation.

Injection of foamer solution doesn't in any way add to any occupational hazard.

7. ECONOMIC CONSIDERATIONS

A pilot test is a field research experiment designed to yield a maximum amount of information; the decision to expand the operation to field size will be based on the results of the pilot. The primary objective of a pilot is to gain information; the cost of the test will be related to the quantity of information desired. The pilot test is not expected to be profitable; it is expected to be economical in the sense that a maximum amount of information is obtained at a minimum cost.

For this proposed field pilot, two five-spots in one reservoir, each having one injection well and four producing wells have been considered. One five-spot pattern will be subjected to the usual steam drive, while the other will be subjected to steam drive with intermittent injection of foamer solution. The steam injection rate would be the same in both the pilots with about 80% quality of steam

As the capital budget for this project is limited, three possible investment scenarios are presented:

- High Investment -- Two five-spot patterns with all required surface facilities purchased and installed;
- Medium Investment -- Two five-spot patterns with surface facilities leased; and
- Low Investment -- Two pairs of producer and injector wells with surface facilities leased.

7.1 BASIS FOR COST ESTIMATE

To arrive at an approximate cost of the basic pilot test for each of the three scenarios, the following assumptions are made:

1) The depth to the reservoir is 1000 ft. (In Kern County, the average depth for heavy oil deposits varies from 700 ft to 1300 ft.) Each five-spot will be on 2.5 acres. Typical Kern County reservoir characteristics are assumed to be applicable here, such as: 30% porosity, 50 ft of displacement zone, and permeability of 1-5 darcies.

2) All wells will be completed with surface casing, 10 3/4" 60 ft conductor; 7" N-80 Buttress casing; 5 1/2" K-55 Buttress liner; and 2 3/8" production tubing (Figs. 2.15 and 2.16).
3) Water lines will be run to a distance of 1,000 ft from the water source.
4) Electrical lines will be installed to a distance of 2,000 ft.
5) The steam generator and auxillary equipment will be purchased or leased for the test period of two years.
6) Although three surfactants, namely Suntech IV, Thermophoam and Corco-180 have been considered for the cost estimate, the aggregate cost figures are based on Corco-180.
7) The test period will be two years.

7.2 COST OF WELLS

The cost estimates for injection and production wells are shown in Tables 7.1 and 7.2, respectively. These cost estimates are then compared with those of the Lewin and Associates Inc.[77] model, and the typical cost incurred by Getty Oil Co. and Chevron U.S.A. Inc. in Kern County (Table 7.3). The costs incurred by these two oil companies are lower than the estimates presented in this report because they have a large number of wells (Getty Oil Co. has more than 2,000) in Kern County. The estimate from the Lewin and Associate Inc. model, on the other hand, is on the higher side as it is a generalized estimate, not specific to the Kern River area.

7.3 COSTS OF SURFACE EQUIPMENT

The following are the appropriate prices of equipment for the treatment of water, generation of steam, injection of steam and foamer solution to the formation, desulfurization of flue gas, demulsification of oil and water and their separation, treatment of produced water and its disposal and disposal of solids and wastes:

1) Water softener;
2) Steam generator, once-through type;
3) Flue-gas desulfurization unit;
4) Free-water knock out unit;
5) Well-testing unit ;
6) Demulsifier;

TABLE 7.1

COST OF STEAM INJECTION WELL
(in 1980 dollars)

DRILLING:	
Move in-out	\$2000
Labor & Equipment Rental Charge @ \$4500/day × 5 day	\$22,500
Conductor Pipe & Cementing	\$1800
Drilling Foam, Mud	\$4500
Equipment Rentals, BOP Stack, Bit Subs	\$3500
Drilling Bits and Stabilizers (Total drilling cost: \$38,800 or \$38.8/ft.)	\$4500
LOGGING:	
Induction Electrical Survey 59¢/ft. or \$600 min. depth charge	\$600
Density-Neutron Log	
\$1240 min. depth charge	\$1240
\$1240 operation charge	\$1240
CORING:	
Side wall Sampling, Base charge	\$540
Sampling, \$49/sample	
For 50 ft. zone, sample/5 ft. recommended, 10× 49	\$490
Transport	\$2000
Supervision	\$1000
Overhead	\$1000

(Continued of following page)

TABLE 7.1 cont.

COMPLETION

Cement	$2500
Rental Equipment	$2500
Perforation	$6000
Washing	$500
Supervision	$800
Overhead	$500
Casing[76] 7", Threaded & Coupled $10/ft 1000 ft.	$10,000
Tubing & Attachments 2 3/8", $3.50/ft. 1000 ft.	$3500
Downhole Equipment, Frangible Centralizer, Steam Deflectors High temp. safety joint, Isolation packers	$6500
Total Cost of Injection Well	$79,710

TABLE 7.2

COST OF PRODUCTION WELL
(in 1980 dollars)

DRILLING:	
Move in-out	\$2000
Labor & Equipment Rental Charge @ \$4500/day x 5 day	\$22500
Conductor Pipe & Cementing, 10-3/4", \$30/ft x 60 ft	\$1800
Drilling Foam, Mud	\$4500
Equipment Rentals, BOP Stack, Bit Stubs	\$3500
Drilling Bits and Stabilizers	\$4500
(Total Drilling Cost: \$38,800 or \$38.8/ft)	
LOGGING:	
Induction Electrical Survey 59¢/ft or \$600 minimum depth charge	\$600
Density Neutron Log \$1240 min. depth charge	\$1240
\$1240 operation charge	\$1240
CORING:	
Side Wall Sampling, Base Charge	\$540
Sampling, \$49/sample For 50 ft zone, sample/5 ft, 10 x 49	\$490
Transport	\$2000
Supervision	\$1000
Overhead	\$1000

(Continued on following page)

TABLE 7.2 (Continued)

COMPLETION:	
Cement	$2500
Rental Equipment	$2500
Perforation	$6000
Washing	$500
Supervision	$800
Overhead	$500
Casing[76]. 7", Threaded & Coupled, $10/ft x 1000 ft	$10000
Tubing & Attachments, 2-3/8", $3.50/ft x 1000 ft	$3500
Downhole Equipment Centralizer & Isolation Packers to change production at breakthrough	$1500
PUMP & PUMPING UNIT 228,000 in. lb-torque; API 228-213-86	
Sucker-rod 3/4", API class "C" string, polished rod, stuffing box assembly	$26000
Total Cost of production well	$100,710

TABLE 7.3

COSTS OF STEAM INJECTION AND OIL PRODUCTION WELLS

(For Wells 1000 ft Deep)

	Estimate of this report	Chevron U.S.A. Inc.[48]	Getty Oil Co.[49]	Lewin & Assoc. Model[77]
Oil Production Well With Pumping Unit	$100,700	90,000	95,000	110,000
Steam Injection Well With Downhole Tools	$ 80,000	70,000	75,000	90,000

7) Tank-battery for produced oil water;

8) Pump-sets for oil and water;

9) Waste water treatment equipment; and

10) Insulated steam lines, water and oil lines.

7.3.1 Water Softener and Waste Water Treatment

Water treatment equipment for steam generation is discussed in detail in Section 3. A small-size treatment plant adequate for the pilot test would cost $50,000. The waste water treatment process is discussed in Section 6 and the cost of such a plant would be $40,000. These cost figures include installation and freight charges. In each injection well, 300 bbl/day of water (converted to steam) will be injected. There will be two injection wells. The cost of chemicals, beads, power and maintenance is, according to a rule of thumb,[78] 15¢/bbl of water treated for steam generation. The cost of treating 600 bbl/day of water is $33,000 per year.

The cost of treating waste water is half as much as treating regular water[78] and therefore, it would be $16,500/year. Hence, the total cost of treating 600 bbl/day of water for steam generation and the resulting waste water for disposal would be $50,000/year.

7.3.2 Steam Generator

The process of steam generation for injection into the formation is discussed in Section 3. C. E. Natco Co. of Bakersfield has been consulted in preparing the following cost estimates.

A small once-through type steam generator, suitable for the pilot test, delivering 22 MM BTU/hr, or 1200 bbl/day of water converted to 80% quality steam will require:

Cost of generator	$190,000
Freight and installation	$ 8,000
Installed cost	$198,000

For 600 bbl of water converted to steam, this generator would consume 30 bbl/day of fuel oil. The uncontrolled price[79] for 13° API Kern River Field is $25/bbl.

Therefore, the annual cost of fuel for generating 600 bbl/day of steam is:

$$\$25/\text{bbl} \times 30\ \text{bbl/day} \times 365\ \frac{\text{day}}{\text{year}} = \underline{\$274,000}$$

7.3.3 Flue-Gas Desulfurization (FGD) Unit

Requirements for desulfurization of flue-gas and the details of the process are presented in Section. A sodium carbonate scrubber suitable for the above mentioned steam generator, if supplied by C. E. Natco Co. of Bakersfield, will cost as follows:

Cost of scrubber	$115,000
Freight and installation	$ 10,000
Installed cost	$125,000

The annual cost of chemicals would be about $25,000.

7.3.4 Free-Water Knock-out Unit

Non-emulsified water is removed before the demulsification separation process by connecting this unit to the producing well. An eight-foot long vessel capable of handling up to 27000 bbl/day of water, supplied by C. E. Natco Co. of Bakersfield, costs as follows:

Cost of free-water knock-out unit	$ 25,000
Freight and installation	$ 1,000
Installed cost	$ 26,000

7.3.5 Well-Testing Unit

This unit records the gravity of oil, gas/oil ratio, water/oil ratio and total volume of fluid produced. Such a unit can be supplied by C. E. Natco Co. or Chemical Oil Recovery Co. at the following price:

Cost per single unit	$ 25,000
Freight and installation	$ 500
Installed cost per unit	$ 25,500

Each production well may be tested once a week and one testing unit is sufficient for eight production wells.

7.3.6 Demulsifier

A six-foot long horizontal heater treater capable of handling 500 bbl/day of fluid, would be adequate for the pilot. The costs are as follows:

Cost of heater treater	\$ 35,000
Freight and installation	\$ 3,000
Installed cost	\$ 38,000

The cost of heating and treatment would be 10¢/bbl of fluid. Therefore, the annual cost of maintenance will be \$18,000.

7.3.7 Tank-Battery

Tanks of different sizes, six to eight in number, will be required for storage of water for steam, treatment and separation of produced water, etc. The costs are as follows:

Cost of tank battery	\$150,000
Freight and installation	\$ 25,000
Installed cost	\$175,000

7.3.8 Pump-sets, Steam Line, Water Line and Powerline

The cost of these units is shown under accessories in Table 7.5.

7.4 COST OF IN-SITU FOAMER SOLUTIONS

7.4.1 Suntech IV

A total of nine synthetic sulfonates and three petroleum sulfonates were prepared by Suntech Inc., under a U.S. DOE contract.[80] Samples of these were distributed to interested academic and research groups for laboratory studies pertaining to tertiary oil recovery. Chiang, et al.[81] reported Suntech IV to be the most promising of the nine synthetic petroleum sulfonates in producing in-situ foam and reducing gravity override effect. Suntech IV is composed of (N-C_{15-18}) and Toluene and has an activity of 69%. Chiang et al.[81] have reported that in-situ foaming increases generally with surfactant concentration until the critical micelle concentration (CMC) is reached; concentration above this has very little effect on the performance of the process. The optimum concentration may vary from 1% to 5%. The recommended volume of foamer solution would be 10% to 20% of pore volume at its optimum concentration.

The cost of Suntech IV[82] if purchased in the amount of 100,000 lb would range from 75¢ to $1/lb. A price of $1/lb will be used in the calculations here. Cost of Suntech IV:

Cost of 1 barrel of 100% active solution	=	
$1/bbl × 8.34 lb/gallon × 42 gallon/bbl	=	$350/bbl
Cost of 1 barrel of 1% active solution	=	$3.50/bbl

Suntech's sythetic petroleum sulfonates were prepared on a small scale exclusively for laboratory use. If these sulfonates are manufactured on a large scale for commercial use, the price will likely be lower (Ref. 82) because of the economy of scale.

7.4.2 Thermophoam BWD

This surfactant is supplied by Far-Best Corp., Los Angeles. The price[83] of this chemical varies with the quantity purchased as follows:

For 1100 gallons and less:	49¢/lb
For more than 1100 gallons and less than 4400 gallons:	47¢/lb
For more than 4400 gallons:	45¢/lb

All the above rates are for 40% active foamer solution which has a specific gravity of 1.0. The cost of 40% active Thermophoam (using the price of 45¢/lb):

$$\$0.45/\text{lb} \times 8.34\ \text{lb/gal} \times 42\ \text{gal/bbl} = \$157.62/\text{bbl}$$

Cost of 1% active Thermophoam BWD:

$$\frac{\$157.63}{40} = \$3.94/\text{bbl}$$

7.4.3 Corco-180

Chemical Oil Recovery Company of Bakersfield sells this foamer. Prices per pound are shown in Appendix F, which include the following items: all process royalty fees, delivery to well location, pumping equipment necessary to properly inject the material into the well, labor and experienced supervision to apply the process with documentation of all pressures and temperatures.

For this pilot test, the price of \$0.75/lb would be applicable, which is at 60% activity. Composition of chemicals in Corco-180 is considered proprietary information and therefore is not disclosed. The density of Corco-180 is 8.1 lb/gal. Cost of Corco-180 at 1% activity (including labor, equipment and royalties):

$$8.1 \text{ lb/gal} \times \$0.75/\text{lb} \times 42 \text{ gal/bbl} \times 1/60 = \$4/25/\text{bbl}$$

Since this rate includes delivery of chemical, equipment, and labor to apply the process with documentation of all pressures and temperatures, it appears to be reasonable in comparison to the cost of 1% active Thermophoam BWD at \$3.94/bbl and 1% active Suntech IV at \$3.50/bbl.

7.5 COSTS OF LABORATORY RESEARCH, FORMATION EVALUATION AND RESERVOIR ENGINEERING

Cost of laboratory research will be \$50,000. Details of all the tests have been discussed in Section 5. Here the cost estimates are provided for each phase of the field test.

7.5.1 Reservoir Definition

Logging: Some basic logs will be run in all wells and the costs of these logs are included in drilling and completion costs. However, further well logging may be done in the injection and observation wells and perhaps two of the four production wells; estimates of these are as follows:

Open Hole Logs:

In two producers, one injection,
one observation well in each 5-spot

\$5220/well × 8 wells	\$ 41,760

Cased Hole Logs:

Standard suite of logs in one injector, one observation well, \$5450/well; cement bond log in all wells, \$920/well

\$920/well × 8 wells + \$5450/well × 4 wells   \$29,000

Coring: Conventional analysis, every foot of 50ft of displacement zone in one observation well, one injector and one producer in each 5-spot:

Taking samples	\$ 12,000
Conventional analysis	\$ 12,000
Special coring;	
Steam flooding 5 samples from each observation well, \$1000/sample	\$ 10,000
Chemical flooding of 5 samples from each observation well, \$1100/sample	\$ 11,000

Injectivity Test: Injectivity profiling by tracer log:

\$1500/injection well	\$ 3,000

Cost of transient well testing is included in general operating and maintenance costs.

Simulation and Reservoir Engineering: \$ 50,000

Total Cost of Reservoir Definition: \$169,520

7.5.2. Reservoir Monitoring

Logging: Temperature Log

\$1200/test, tested monthly for 2 years in each observation well	\$ 57,000
All other logs, run every 3 months for 2-year test period, in each observation well: \$4090/well/test	\$ 65,440

Tracer Response Analysis: Tracer material and analysis	$ 50,000
Tracer log: 4 runs/yr × 2 yr × $1200/run	$ 19,200
Simulation and Reservoir Engineering:	$ 50,000

Costs of transient well testing and analysis of produced fluids are included in general operating and maintenance costs.

Total Cost of Reservoir Monitoring	$241,640

7.5.3 Post-Pilot Study

Coring: Drilling of core holes, on in each 5-spot	$100,000
Conventional analysis, 50 samples in each special coring (as in reservoir definition)	$ 4,200
Steam flooding on 5 samples from each core hole	$ 10,000
Chemical flooding on 5 samples for each core hole	$ 11,000
Simulation and reservoir engineering	$ 20,000
Total cost of post-pilot study	$145,200

7.6 EQUIPMENT LEASING COST

Total cost of equipment	$812,000
Duration of lease period	2 years

Assumptions

1) Lessee will pay all maintenance just as if he owned the equipment.
2) Lessor realizes 30% rate of return before income taxes are paid.
3) Life of all equipment is 10 years for lease purposes (usually the life of equipment considered here is 16 years, but in the leasing business life is reduced because of movement of equipment).
4) A salvage value of 7% of initial cost is expected (i.e., $56,840).

Calculations of the Lease of Surface Equipment

1. Principal investment P = Initial Cost - Salvage

   = \$ (812,000 - 56,840)

   = \$755,160

2. Capital recovery factor

$$\frac{A}{P} = \frac{i(1 + i)^n}{(1 + i)^n - 1}$$

where:

P represents a present sum of money

A represents the end of year payment

I represents an interest rate per year

n represents number of years

Substituting:

$$\frac{A}{755{,}160} = \frac{.30\ (1 + .30)^{10}}{(1 + .30)^{10} - 1} = .32346$$

From this, annual lease payment (A) = <u>\$244,264</u>

This lease payment cost is included in plant cost for Scenarii 2 and 3 in Table 7.4.

Table 7.5 is a summary of the costs associated with the scenarii for high, medium and low investments.

TABLE 7.4

COST OF PILOT

	HIGH INVESTMENT TWO 5-SPOT WITH EQUIPMENT PURCHASE	MED. INVESTMENT TWO 5-SPOT WITH LEASED EQUIPMENT	LOW INVESTMENT TWO PAIRS PROD. & INJ. WELL. LEASED EQUIPMENT
BASIC WELL COSTS (1000 ft. deep)			
Producing well completed @ $100,710/well	$805,680	$805,680	$201,420
Injection well completed @ $79,700/well	159,400	159,400	79,700
Observation well completed @ $55,000/well	110,000	110,000	55,000
I Total Well Cost	$1,075,080	$1,075,080	$336,120
EQUIPMENT			
Steam Generator, 22 MMBTU/hr	$198,000		
Water Softener for Steam	50,000		
Scrubber (Desulfurizer)	125,000		
Heater Treater (Demulsifier)	38,000		
Free-Water Knockout Unit	26,000		
Well-Testing Unit	25,500		
Waste-Water Treatment Equipment	40,000		
Tank-Battery	175,000		
Accessories, distribution of steam oil, water & power	134,000		
II Total Equipment	$811,500		
TOTAL WELL COSTS & EQUIPMENT (I & II)	$1,886,580	$1,075,080	$336,120

(Continued on following page)

TABLE 7.4 (Continued)

	HIGH INVESTMENT	MED. INVESTMENT	LOW INVESTMENT
III. EQUIPMENT LEASE per year		$244,300	$244,300
OPERATION & MAINTENANCE COSTS			
Production Well @ $30,000/yr.	240,000	240,000	120,000
Injection Well @ $30,000/yr.	60,000	60,000	60,000
Observation Well @ $18,000/yr.	36,000	36,000	18,000
Steam Generator	274,000	274,000	137,000
Water Softener for Steam	33,000	33,000	16,500
Scrubber (Desulfurizer)	25,000	25,000	12,500
Heater Treater	18,000	18,000	9,000
Waste Water Treatment	16,500	16,500	9,000
Water for Softening	20,000	20,000	10,000
Accessories, distribution systems, pumps	25,000	25,000	15,000
Power	25,000	25,000	20,000
Labor & Supervision	150,000	150,000	100,000
COSTS OF CORCO INJECTION @ $36,000/injection well	72,000	72,000	72,000
Overhead & contingencies	100,000	100,000	50,000
IV. TOTAL YEARLY O & M COSTS	$1,094,500	$1,094,500	$613,000

(Continued on following page)

TABLE 7.4 (Continued)

	HIGH INVESTMENT	MED. INVESTMENT	LOW INVESTMENT
FORMATION EVALUATION & RESERVOIR ENGINEERING			
1. Reservoir Definition	$169,520	$169,520	$50,000
2. Reservoir Monitoring	$241,640	$241,640	$143,000
3. Post-Pilot Study	$145,200	$145,200	$80,000
	$556,360	$556,360	$273,000
LABORATORY TEST	50,000	50,000	50,000
V. TOTAL COST OF TESTS	$606,360	$606,360	$323,000
ESTIMATED TOTAL EXPENDITURE ON 2-YEAR PILOT TEST (I to V)	$4,681,940	$4,359,040	$2,373,720

TABLE 7.5

SUMMARY OF COST ESTIMATES OF THE PILOT

	HIGH INVESTMENT	MEDIUM INVESTMENT	LOW INVESTMENT
Configuration	TWO 5-SPOT PATTERMS WITH SURFACE FACILITIES PURCHASED	TWO 5-SPOT PATTERNS WITH SURFACE FACILITIES LEASED	PAIR OF PRODUCER-INJECTOR WELLS WITH SURFACE FACILITIES LEASED
Total	$4.6 MM	$4.3 MM	$2.36 MM
CAPITAL INVESTMENT	$1.88 MM	$1.08 MM	$ .34 MM
TESTING	$ .60 MM	$ .60 MM	$ .32 MM
YEARLY O & M	$1.1 MM	$1.35 MM	$ .86 MM

8. CONCLUSIONS AND RECOMMENDATIONS

Design considerations for the proposed field pilot to test in-situ foaming with steam drive have been described in detail. Steam drive is the most commonly used enhanced oil recovery process. However, the phenomena of gravity override and channeling of steam sharply reduce the oil recovery potentially achievable by steam drive. Laboratory studies in SUPRI have shown that the use of in-situ foaming with steam is a potential means for reducing gravity override and steam channeling. The results of this field pilot will be very important in confirming laboratory results and in establishing this new recovery technique for heavy oils.

Following are the important conclusions and recommendations of this study:

1) Laboratory research has shown that the use of in-situ foaming reduces the effect of gravity override and improves vertical conformance. However, more extensive work needs to be done prior to field testing on foamability, effectivness in permeability reduction, absorption losses, optimum slug size, partitioning and surfactant longevity.
2) Before starting the pilot, in-situ foaming should be tested with steam; simulation of actual reservoir conditions whould be carried out in the laboratory. The data gathered here would be crucial to the field pilot design.
3) Under the low investment scenario presented, namely, two pairs of a producer and an injector, it is difficult to achieve reliable reservoir information. This scenario is therefore the least desirable.
4) In both the medium and high investment scenarios, two five-spots on 2.5 acres each have been considered. To allow a better comparison of performance with and without in-situ foaming, nine

five-spots in each pilot may be employed; the budget available to SUPRI would not allow this.

5) The costs of 1% active surfactants have been estimated as:

Suntech IV	:	\$3.5/bbl
Thermophoam BWD	:	\$3.94/bbl
Corco-180	:	\$4.25/bbl

The cost of Corco-180 includes delivery of chemical, equipment, and labor to apply the process with documentation of all pressures and temperatures.

6) Corco-180 has been utilized in the cost estimate for this pilot test. However, if Suntech IV is used for in-situ foaming, it has to be custom-made for the entire need of the two-year test period. The following precautionary measures need to be taken:
   (i) To avoid the possibility of oxidation in transportation and storage during the entire field test, Suntech IV should be kep under an inert gas blanket such as nitrogen, flue gas, or natural gas.
   (ii) During the winter season the ambient temperature may be sufficiently low to solidify Suntech IV. Adequate methods to heat and dilute it with water before injection should be considered. This problem will not be applicable to Corco-180 as it can be delivered and injected as needed.

7) The annual cost of injecting a foamer solution with steam is about \$36,000/injection well in the Kern River field. This can be economic if an incremental 3.5 bbl of oil/day is produced per injection well due to in-situ foaming with steam drive, at the prevailing prices of crude oil and surfactants.

8) Extensive tests for formation evaluation and reservoir engineering should be performed as outlined in this study; the entire cost of which is only 12% of the total cost of the field test.

9) Flue gas emission regulations are being changed and will become progressively more stringent by 1984. More expensive and efficient FGD processes may be employed for flue gas control in the future.

10) Most production and injection wells are not equipped with downhole tools. But such tools appear desirable for this pilot for improving steam stimulation efficiency.

11) It is cheaper to buy the surface equipment than to lease it, if the test period is longer than two years.

Since this report was drafted, a site for the proposed SUPRI pilot has been chosen--the McManus lease in the Kern River Field. Appendix G gives the details of this site, and Appendix H gives cost sharing estimates of this field pilot test.

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APPENDICES

APPENDIX A

WILLIAMS HOLDING STEAMFLOOD PILOT (Ref. 19)
SUMMARY OF ACTUAL OPERATING COSTS TO DATE
($/BBL OIL PRODUCED)
Period: June 25, 1976 to December 1, 1979

Item	Cost
Displacement Generator (excluding fuel)	$ 1.28
Displacement Fuel	5.51
Contract Services	2.49
Company Services	0.71
Materials and Supplies	1.17
Utilities	0.46
Central Plants	0.50
Cyclic Stimulation	0.82
Engineering and Supervision	0.45
Computer and Deliverables	0.08
General and Administrative	0.46
Total Operating Costs	$13.93
Major Well Workovers[1]	(1.28)
Operating Costs Excluding Major Well Workovers	$12.65

[1] The major well workover costs only include the liner replacements that were required on WH 205, WH 36, and the four pilot steam injection wells.

APPENDIX B

CASING FAILURES - THERMAL STRESSES (Ref. 87)

FAILURE MECHANISM

- Unrestrained casing when heated elongates in direct proportion to change in temperature (Δt) approximately 0.8"/100'/100°F.

- Restrained casing (not free to elongate) when heated elongation is replaced by compressive stress buildup in the casing.

- Failure may occur when temperature-generated compressive stresses exceed the joint strength or yield strenght of casing.

  - Permanent deformation of casing material or joint during heating may result in tensile failure with subsequent cooling while well is shut in.

FAILURES

- Most failures are found in joints although a few instances of collapse have been reported.

- Joint failures are either fracture or pull-out type failures.

- Collapse failures normally occur in washed-out unsupported sections of casing that allow casing buckling and excessive bending stresses.

ALLOWABLE TEMPERATURE CHANGE

Casing Grade	Minimum Yield (psi)	Allowable[1] Δt, $^{\circ}$F
J or K	55,000	275 (135° C)
N	80,000	400 (204° C)
P	110,000	500 (288° C)

[1] Approximates 200 psi stress for each degree increase.

APPENDIX C

CASING DESIGN--BASIC FACTORS CONSIDERED (Ref. 87)

GENERAL

- Casing properties set forth in API standards are used.
- Designs based on biaxial loading of pipe including effects of dog legs.
- Casing Sizes--economic selection.

DESIGN

- Logitudinal tension:
  - Based on apparent buoyant weight of casing.
  - Body strength to have minimum yield strength that exceed tensile stress due to suspended weight, bending and reciprocation (F.S. = 1.5).
  - Joint strength must exceed tension due to suspended weight, bending and reciprocation (F.S. = 1.92).
- Collapse:
  - Must withstand collapse pressure of full column of mud outside and no pressure inside casing (F.S. = 1.06).
  - Thermal effects on tensile loading are no considered.
- Burst:
  - Allowable internal pressure must exceed the difference between internal and external pressures (F.S. = 1.25).
  - Possible controlled internal pressures (squeeze, stimulation) are considered (F.S. = 1.15).

APPENDIX D

CASING DESIGN & PRACTICES--THERMAL WELLS (Ref. 87)

CASING JOINTS

- Only buttresss type couplings have joint strength equal to or greater than body strength are used.

CEMENTING

- Full length cementing of each casing string (except slotted liners) are programmed.

THERMAL STRESSES

- Maximum temperature difference between casing cemented and producing condition are estimated.

- Body and joint strengths selected must be suitable to withstand expected thermal compressive stresses.

- Alternate casing practices versus use of higher strength casing to withstand thermal stresses are considered such as:

  - Pre-stressing casing by direct tensie loading or thermal elongation during cementing operations.

  - Expansion joints.

  - Liner completions that provide for expansion.

  - Use of larger diameter casing.

APPENDIX E

TYPICAL CEMENTING PROCEDURES (Ref. 87)

- Make wiper and mud conditing run to T.D. reduce mud viscosity, density and solids to lowest practical values.

- Run casing equipped with guide shoe, float collar, centralizers, scratchers and stage collars (if required) to T.D. circulate at 50±ft^3/minutes until stable conditions attained or at least one hour.

- Precede cement with 200± ft^3 freshwater (or treated) and bottom plug.

- Cement with design volume of cement specified.

- Displace cement with top plug followed by specified volume of mud to bump plug. Displace at 50± ft^3/minimum. Estimated job times: surface casing--60± minutes with WOC time of 8 hours; production liner--160± minutes with WOC time of 12 hours.

CORCO CHEMICAL OIL RECOVERY COMPANY
(805) 322-6059 • P.O. BOX 9666 • BAKERSFIELD, CALIFORNIA 933

PRICE LIST

Effective February 15, 1980

COR-180 (Bakersfield Area)

Pounds	Price
1) 450 - 1,349	$ .96
2) 1,350 - 4,050	.88
3) 4,051 - 11,249	.83
4) 11,250 - 19,999	.78
5) 20,000 +	.75

The above costs reflect price of chemical, labor and equipment for injection at the well head.

APPENDIX G

McManus Lease Sections 10 and 13, Kern River Field
Kern County, California.

Properties of Reservoir:

Total field area:	80 acres
Depth:	600-700 ft.
Productive zone:	65-85 ft.
Porosity:	30-35 percent
Permeability:	500-12,000 md.
Produced oil:	13° API
Formation Volume Factor:	1.0
Production:	40 BBL/day/pattern
Steam injection:	400-600 BBL/day
Injection pressure:	110-115 psig
Water quality:	85 ppm TDS

Area of each five-spot: 2.25 acres

Production and injection wells are gravel packed with blotted pattern.

APPENDIX H

COST ESTIMATE FOR THE CHOSEN SUPRI PILOT SITE

McManus Lease, Kern River Field, Kern County, California.

Details of this site are mentioned in Appendix 7.

All tests are described in Section 5 and their cost estimates are calculated in Section 7.

OBSERVATION WELLS	3 Five-Spots	2 Five-Spot
1. Initial wells (drilling and completion).		
@$60,000/well x no. wells	$180,000	$120,000
2. Post Pilot Wells (drilling of core holes)		
@$45,000/well x no. of wells	$135,000	$ 90,000
Total observation well costs	$315,000	$210,000

LOGGING OBSERVATION WELLS		
1. Open hole (Initial and Post-Pilot wells)		
$5220/well x no. of wells	31,320	20,880
2. Cased hole (Initial wells only)		
Temp. Logs:		
$1200/test x 12 test/yr. x 2 yr. x no. of wells		
	86,400	57,600
All other logs:		
$4090/test x 4 test/yr. x 2 yr. x no. of wells		
	98,160	65,440
Total logging costs	$215,880	$143,920

CORING OBSERVATION WELLS	3 Five Spots	2 Five-Spots
1. Conventional Analysis:		
$42/sample x 50 samples/well x no. of wells	$12,600	$ 8,400
2. Special Analysis:		
Steamflooding, 5 samples from each well		
$1000/sample x 5 sample/well x no. of wells	$30,000	$20,000
Surfactant flooding, 5 samples from each well		
$1100/sample x 5 sample/well x no. of wells	$33,000	$22,000
Total Coring Costs	$75,000	$50,400

WELL-TO-WELL TRACER TEST

Tracer Material: Tritrium gas or		
tritrated water:		
100 curie x $50/curie	5,000	5,000
Labor and Injection costs	5,000	5,000
Analysis:		
One sample/day for first 2 seeks		
One sample/week for the next 8 weeks		
One sample/month for the next 12 months		
34 samples/well x $75/sample x no. of wells	30,600	20,400
Total Tracer Analysis costs	$40,600	$30,400

COST OF STEAM GENERATOR FUEL

25 MM BTU/hr* capacity generator consumes 65-80 BBL of crude oil/day. Current cost of Kern River 13° API crude oil is $25/BBL. An increase of 25% is assumed for the next year. Steam generator consumption of 80 BBL/day is assumed in case of 3 Five-Spots and 60 BBL/day in case of 2 Five-Spots. It is also assumed that 50% cost of generator fuel will be shared by the operator.

	3 Five-Spots	2 Five-Spots
40 BBL/day x 365 day/yr. x ($25/BBL + 1.25 x $25/BBL)	821,250	615,938
60 BBL/day x 365 day/yr. x ($25/BBL + 1.25 x $25/BBL)		615,938
Generator fuel cost to this project	821,250	615,938

* The capacity of generator considered in Table 7.5 is 22 MM BTU/hr.

COSTS OF SURFACTANTS:

(In case of three Five-Spots, two will be injected with in-situ foam and steam, whereas in case two Five-Spots, one will be injected with in-situ foam and steam.)

CORCO-180: ($36,000/inj. well/yr. x 2 yr. x no. of inj. well)

	3 Five-Spots	2 Five-Spots
	144,000	72,000
Reservoir eng. Study:	250,000	250,000
Laboratory Support	100,000	100,000
Administrative Costs, Other Expenses and Overhead (10%)	200,000	150,000
Total Costs	$2,161,730	$1,622,658