ENHANCED OIL RECOVERY TECHNIQUES Syllabus

UNIT-VI

- **Steam flooding for enhanced oil recovery: Chap 11 (P 317-346)**

  Introduction- Theory- Screening criteria for steamflood prospects- Reservoir rock and fluid properties- heat losses and formation heating- oil recovery calculations- An overview of steamflood modeling, parametric studies in steam flooding- Economics of the steam flooding process.

- **Operational aspects of steam injection processes: Chap 12 (351-395)**

  Introduction- Water treatment for steam generation- Steam generators- Determination of steam quality- Wells- Production facilities- Moving the crude oil from the field- Disposal special situations, Operations.

STEAMFLOODING FOR ENHANCED OIL RECOVERY

INTRODUCTION:

- Steamflooding (SF) has acquired a major role in the tertiary recovery of heavy, viscous crude oils.
- The injection of steam generated at the surface or downhole (to reduce heat loss) continuously, or in cycles.
- Continuous injection called steam drive or steamflooding, provides a higher ultimate recovery, so used often.
- Cyclic steam injection, is also known as ‘steam soak’ or ‘huff & puff’, is a single well operation. Steam is injected into a well (producer) for some time, is allowed to soak for a period of time, and the well is subsequently returned to production.
- Recoveries from SF are typically in the range of 50-60% of OIP. The ultimate recovery cyclic steam injection is considerably lower (10-15%).

Steam is believed to increase oil recovery by

1. Reducing the oil viscosity in-situ, allowing the oil to flow more readily;
2. Reducing the residual oil saturation & improving relative permeability to oil;
3. Improving the sweep efficiency ;
4. Increasing the formation volume factor
5. Vaporizing and distilling condensable hydrocarbons from the crude;
6. Providing a gas mechanism.

– Fig 11.1 data from California, 10-20^{0}API gr, incremental oil rate 199,000 bbl/day, which amounted to 20% of the state's total production (1979).
– Currently the process amounts for more than 500,000 bbl/d of heavy oils worldwide, of which 400,000 bbl/d are in USA

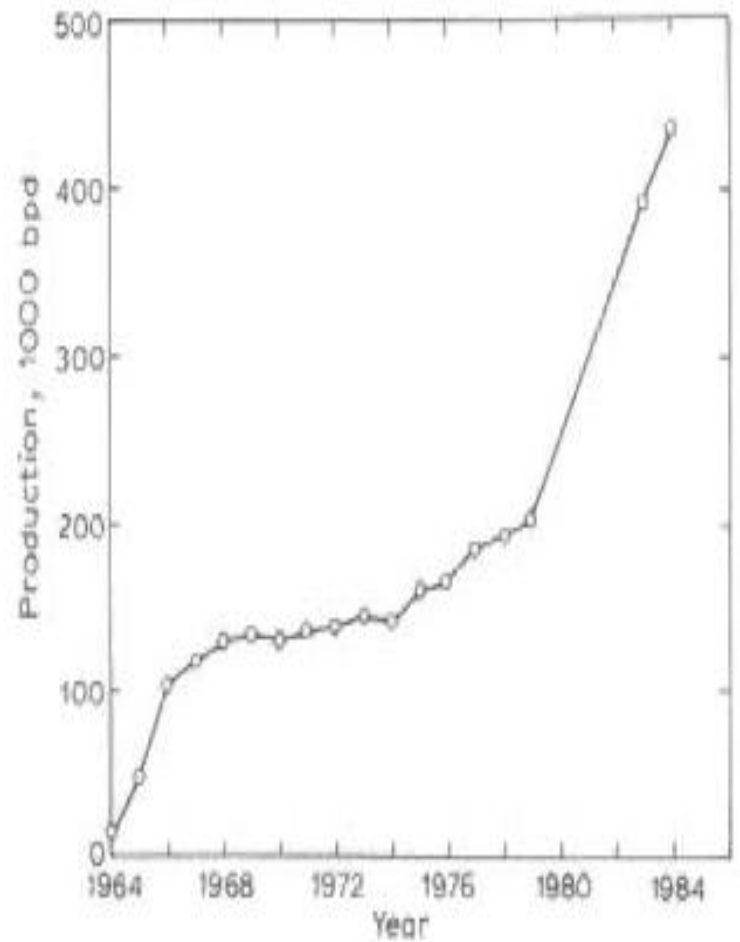

Fig. 11-1. Total production increase in California due to thermal recovery processes.

THEORY: The process of SF depends upon the following parameters

(1) Alterations in the fluid properties in situ. These comprise changes in phase behavior, densities, viscosities, composition, compressibilities, and P-V-T relationships.

(2) Rock properties such as absolute permeability, porosity, rock compressibility, and the attendant changes in these properties on the injection of steam.

(3) Properties related to fluid–rock interaction. These include residual saturations (related in turn to wettability, interfacial tension, etc.), relative permeabilities, capillary pressures, and their dependence upon temperature.

(4) Thermal properties of the formation and the contained fluids, such as specific heats, thermal conductivities, thermal expansion coefficient, and the changes induced in these.

(5) The reservoir environment: net/gross ratio (presence of shale barriers, etc.), heterogeneity, properties of the overburden and underburden, the initial oil saturation, temperature, and pressure.

(6) Flood geometry: pattern shape and spacing, producing–injecting interval (well completion) location and thickness.

(7) Parameters within the operator's control, such as steam injection rate, steam quality, injection pressure (temperature), cumulative amount of injection,

THEORY (continued)

- **The oil in the immediate vicinity of the steam injection end is vaporized & pushed a head. A fraction of the oil is not vaporized and is left behind but at a higher temp due to the heat provided by steam.**
- **The advancing steam eventually condenses, due to heat losses, thereby generating a hot condensate bank. This hot water bank drives oil ahead as it moves, cooling down to reservoir temp.**
- **From this point onwards, displacement process continues as it would be in a conventional waterflood. It is clear that there are three distinct flow regimes: 1. steam zone, 2. hot condensate zone, 3. cold water zone.**

Steam zone:

- ➢ **The predominant effect in the steam zone is steam distillation. High temp and the presence of a gas phase lead to the vaporization of the light ends, which are carried forward by the advancing steam until they condense in the cooler portion of the reservoir.**
- ➢ **The relatively heavier components of the oil, characterized by a high vapor pr, are left behind. The actual oil recovery by steam distillation is determined by the composition of the oil involved.**

Hot-water zone:

- The oil recovery for the hot-water zone is largely governed by the thermal characteristics of the oil involved. If the viscosity of the oil exhibits a sharp decrease with an increase in temp, considerable amount of oil will be recovered by the hot waterflood.
- Based upon residual saturation and relative permeability models, this can lead to the recovery of as much as 10-20% of the oil in the underlying zones of the reservoir not swept by steam.

Cold-water zones :

- The oil recovery from the cold-water zone is approximately equal to that for an equivalent waterflood, a residual oil saturation of about 20-35% is achieved.

SCREENING CRITERIA FOR STEAMFLOOD PROSPECTS:

Depth:

- In designing steam injection projects, the depth of the reservoir is significant parameter. A shallow depth is preferable because,
  1. Wellbore heat looses are minimal in shallow reservoirs.
  2. Deeper formations already have a high temp & incremental benefits from steam injection are low.
  3. Higher formation pressures at greater depths require higher temp operations.
- For successful steam injection project, depth range is 2500’-5000’.
- Reservoir pr & temp are related to its depth. Reservoir prs in excess of about 700 psia require a steam temp of 500^0 F or greater.
- Usually, low formation pressures are desirable. A steam temp of 300-400^0F is considered optimum.

Formation Thickness (FT):

- Formation thickness primarily affects heat loss to the overburden and under-burden. Thus, thicker the formation, better is the steam flood process performance. FT, 10-20’ yields satisfactory performance.

Residual oil-in-place (ROIP):

- The residual OIP should be at least 40%. It is suggested an in-place oil saturation S_o of greater than 50%. The porosity-oil saturation product ϕS_o , is another measure of the OIP (0.15-0.22). Generally, an oil content of 1200 bbl/acre-ft or more is considered economically viable for SF.

Oil viscosity:

- The optimum oil viscosity is placed in the range of 1000-4000cP. It is suggested an oil viscosity range of 200-1000cP for successful SF projects

Oil gravity:

- Oil gravity, indicative of the composition of oil, also affects recovery, in broad terms it must be in the range of $10\text{-}36^0$ API.

Formation permeability (FP):

- FP should be high enough to permit steam injection at adequate rates & to ensure rapid oil flow towards wellbore, 100-4000 mD is satisfactory.
- It is suggested kh/μ must be 50-100 or above where k = formation permeability, h = thickness, μ = oil viscosity.

RESERVOIR ROCK AND FLUID PROPERTIES:

Residual saturations:

- Wettability changes with temp: the oil-water-rock contact angle decreases as temp increases, i.e. the rock becomes more water-wet at higher temps. The following generalizations can be inferred;
  1. There is no effect of IFT on residual saturations and relative permeabilities for high tension (σ > 1 dynes/cm) systems.
  2. With increasing temp, residual oil saturation decreases, where as residual water saturation increases.
  3. With increasing temp, the relative permeability curves shift to the right, i.e., relative permeability to oil increases, where as relative permeability to water decreases at any given saturation.
- It has described two approaches for correlating residual oil and water saturations. The first neglects viscous forces, which for many systems are low relative to surface tension at low reservoir flow rates, and correlates the residuals as a function of temp directly.
- A general approach, applicable to thermal & chemical EOR methods, that uses capillary number, N_o, as the correlating parameter.

Viscosity:

- Most heavy oils are highly viscous, ranging from 100 cP to a few million cP at reservoir conditions. In the Beggs-Robinson method, the temp dependence of viscosity is accounted for as a function of oil gravity.

Fluid densities:

- Several correlations are available for estimating oil density. It can be calculated as a function of temp, pr, composition using the thermal expansion coefficient and compressibility.

Phase behavior parameters:

- The system consists of 3-phases, aqueous (H_2O), oleic (oil) & gaseous; 1. aq phase: water, 2. oleic: hc components and 3. gaseous: hc components, and water (steam).
- The phase behavior involves 2 different activities:
  1. hc partitioning between the liquid (oleic) & gaseous phases,
  2. steam partitioning between the liquid (aq) and gaseous phases.
- The aq & oleic phases are often assumed completely immiscible to simplify flash calculations. Steam table data is used for determining steam saturation pr, quality, density, etc.

Thermal properties of the rock:

- Thermal conductivity and diffusivity of the adjacent formations is required for computing the heat loss to overburden & underburden.
- Thermal diffusivity, α (ft^2/hr), is the ratio of thermal conductivity & volumetric heat capacity M. M is the sum of the contributions by the rock grains & the contained fluids (water, oil, and gas).
- Generally, rock thermal conductivity increases with an increase in liquid saturation or a decrease in porosity or temperature.
- Usually, about 2/3 of the injected heat is utilized in heating the rock matrix with the result the enormous amounts of heat are left behind after the injection fluid has displaced most of the OIP.
- Injection of cold water following steam injection has been successfully used in transporting this heat downstream. For the same reason water is injected with air in the in-situ combustion process.
- Water and steam enthalpies and internal energies can be determined from steam tables.

HEAT LOSSES AND FORMATION HEATING:

- In a steam flooding process, steam is the heat transfer medium used for heating up the formation. Only a part of the heat supplied to the steam in the boiler goes into formation heating.
- From the steam boiler to the heat front in the reservoir, the following are the sources of heat loss:
  1. Surface (steam generator & piping),
  2. wellbore (tubing, casing),
  3. heat loss to adjacent formations (over-and under-burden)

Heat losses at the surface:

- About 20% of the heat supplied to a surface steam generator is lost to the flue gas that leaves the stack at around 400^0F. Another 3-5% is lost even in a well designed, insulated pipe line that carries the steam to the injection wellhead.
- The basic eqn. used to calculate heat loss per unit length of pipe, Q_{ls}

  $Q_{ls} = (T_b - T_a)/R_h$ where Q_{ls} is in Btu/hr-ft pipe, T_b is the bulk temp of the fluid in the pipe (^{0}F); T_a is the ambient temp (^{0}F); & R_h is the resistance to heat transfer (Btu/hr-^{0}F-ft pipe)$^{-1}$

Heat loss in the wellbore:

- As steam moves through the wellbore, there is a loss of heat to the surrounding formations due to the difference between fluid and geo-thermal temps. Wellbore heat losses can be high enough, especially in wells that are deep or where steam injection rates are low, to reduce steam to hot water at the formation rockface.
- Steam is usually injected through an insulated tubing; other techniques to reduce heat transfer through the casing-tubing annulus include
  1. Use of concentric tubing strings with insulators between the strings,
  2. Crude oil in the annulus to prevent steam leaks & prevent radiation,
  3. Gas pack – displacing the annulus with high pr gas.
- Steam quality at the bottomhole (rockface) is usually lower than at the surface. A combination of high steam rate, small tubing size, high injection steam quality, can result in lower bottomhole prs and higher bottomhole steam quality.

OIL RECOVERY CALCULATIONS:

- There are several ways of predicting the performance of steam drive, cyclic steam injection and hot water injection process:
  1. mathematical modeling;
  2. scaled physical models;
  3. analytical methods;
  4. correlations developed using any of the above three models.
- In a real reservoir the analysis is far more complex. Some of the phenomena that defy description are:
  1. viscous fingering of the steam,
  2. flow description for multi phase,
  3. gravity segregation of steam &
  4. reservoir heterogeneity .

Steamflooding: Computer models and lab & field tests show that the ultimate oil recovery depends, in many cases, upon the volume of the reservoir that is heated

Cyclic steam injection: In cyclic steam injection, steam is injected for 2-4 weeks at a high rate. The well is returned immediately to production, or shut-in for a few days. Subsequently, the well produces oil for a few months, or up to 1yr, at an improved rate.

These cycles are repeated several times till the economic limit is reached. Generally, oil production rate and amounts of oil produced fall off in the later cycles.

PARAMETRIC STUDIES IN STEAMFLOODING:

The effect of various parameters on oil recovery can be investigated relatively easily using a simulation model. (by Gomaa)

Porosity:

High-porosity reservoirs produce more oil than low-porosity reservoirs per bbl of steam injected due to the larger heat loss in the rock matrix in the latter case.

- **But when converted to fractional recovery basis (% OIP), the recovery is as per Gomaa, almost independent of the porosity for the same steam injection rate per unit reservoir volume (fig.11.4).**
- **A higher porosity suggests larger pore sizes & higher pore connectivity which will significantly alter the flow resistance offered to the oil bank.**

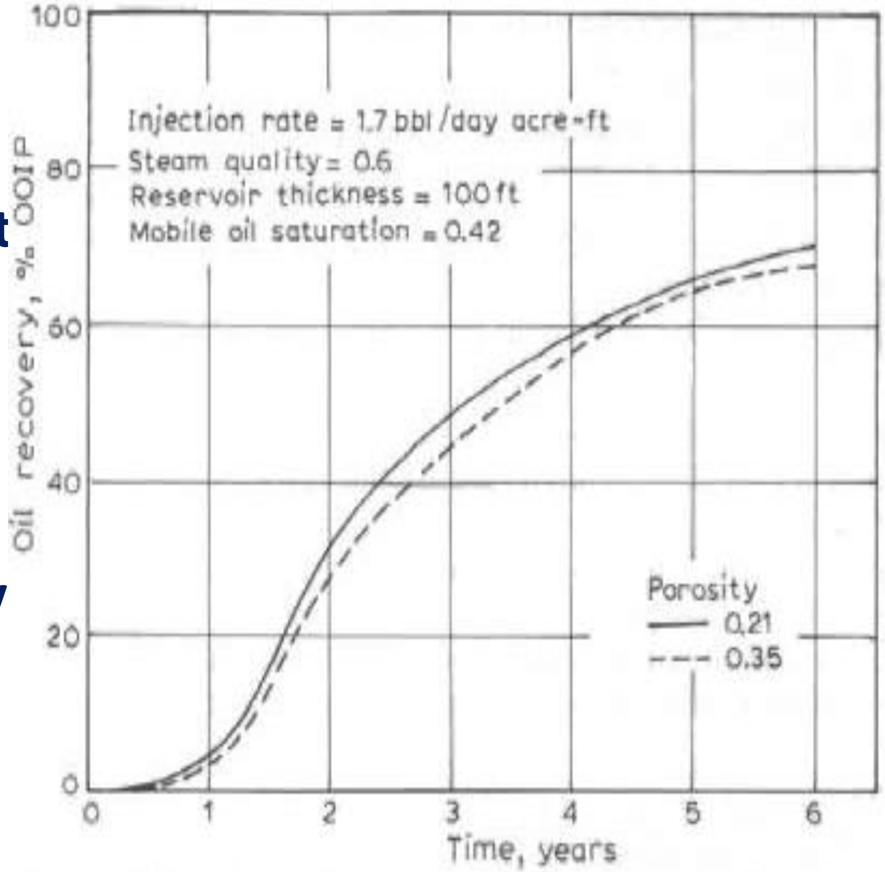

Fig. 11-4. Effect of porosity on steamflood oil recovery. (After Goma

Reservoir thickness (RT):

* RT has been conceptualized on the heat loss to the overburden and underburden. Fig 11.5 shows that recovery is higher for thicker reservoirs. After accounting for heat lost to the surroundings, oil recovery curves for reservoirs with different thickness should become nearly identical, as shown in fig. 11.6 from Gomaa's work.
* RT play an important role and Gomaa's results are merely a simplification.
* RT determines the vertical temp gradient, extent of steam override, the steam-oil saturation profile, and the logistics of the advance profile in the reservoir.

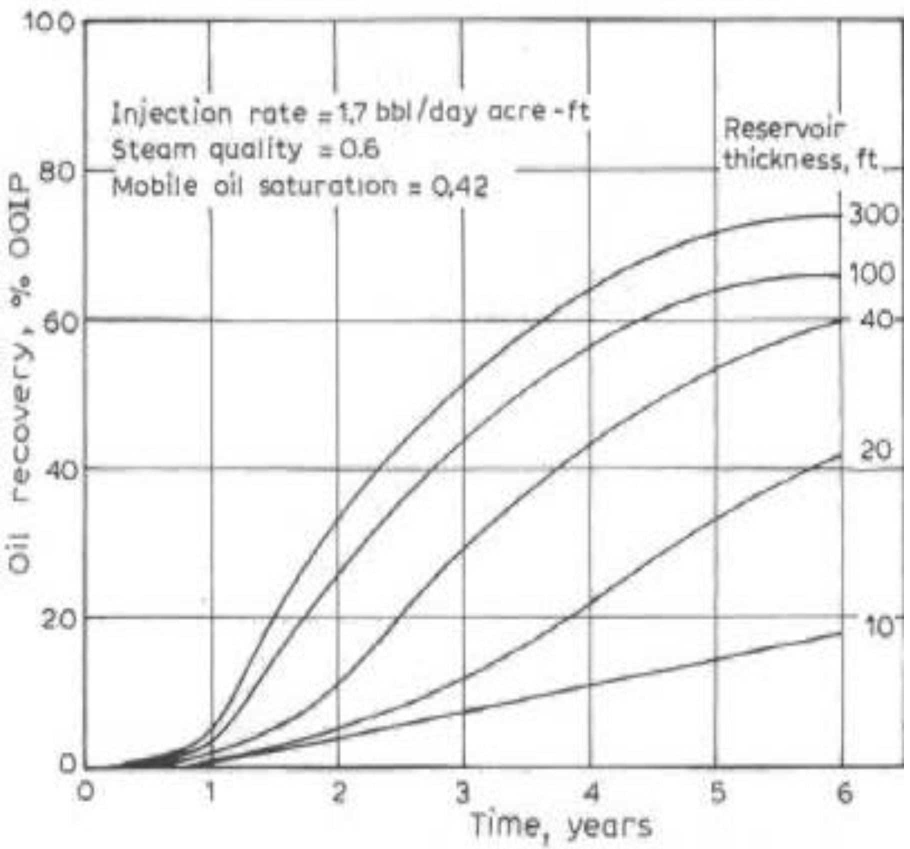

Fig. 11-5. Effect of reservoir thickness on steamflood oil recovery.

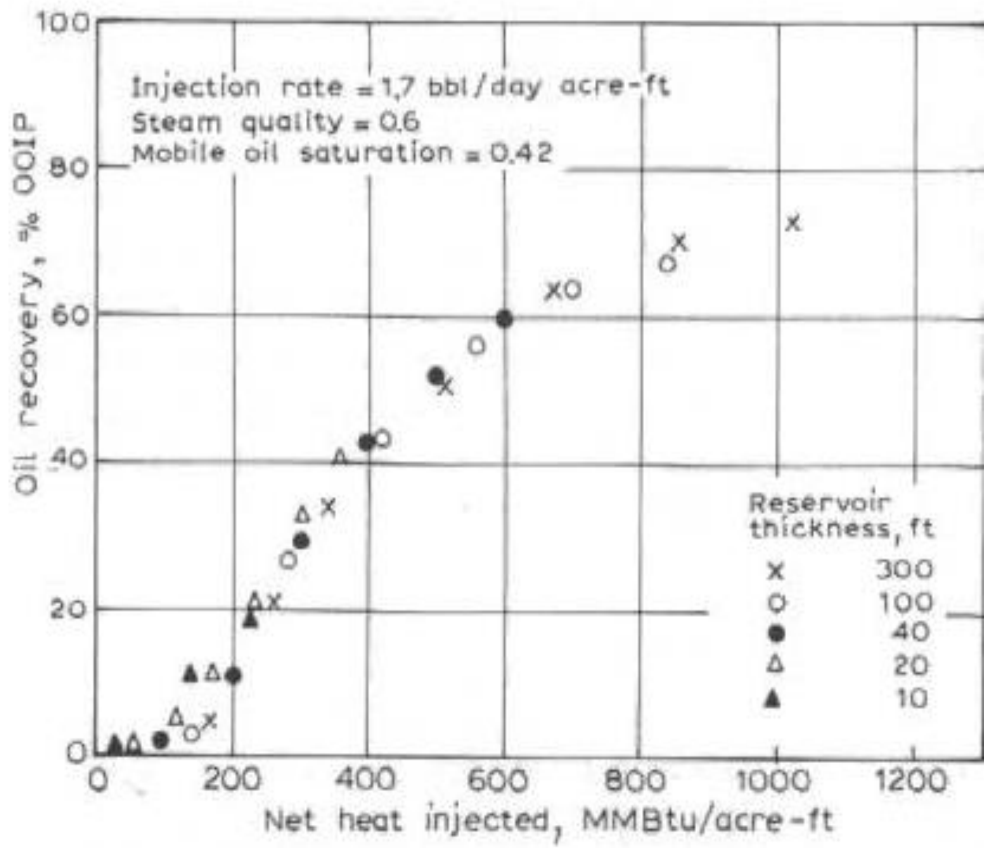

Fig. 11-6. Effect of reservoir thickness on steamflood oil recovery. (

Net/ gross ratio (NGR):

- The net/gross ratio is a measure of the presence of any discontinuous shale streaks that reduce the net productive thickness without diminishing vertical communication.
- This situation may be modelled using 1) an effective porosity and permeability equal to the product of the NGR and the producing sand porosity and permeability, resply. & 2) the gross reservoir thickness as the effective thickness.
- Shaly sands require higher steam/oil ratios than clean sands.

Mobile oil saturation (MOS):

- MOS is defined as the difference between the oil saturation prior to the steamflood and the residual oil saturation after the steamflood.
- Higher the MOS higher is the ultimate recovery as well as the rate of recovery. The increased ultimate recovery results simply from the greater amount of recoverable OIP per unit reservoir volume.

Pattern geometry:

- In reservoir simulators, there are no limitations imposed on well productivity.
- This will lead to a model prediction that neither the pattern shape nor the spacing influence oil recovery for a fixed injection rate per unit reservoir volume.
- This does not hold true for actual field projects where such limitations do exist & patterns with higher producer-to-injector ratios yield better recoveries.

Injection rate:

To eliminate the effect of several geometrical factors, steam injection rate is commonly expressed on a unit reservoir volume basis. Several investigators had described the effect of steam injection rate as being significant.

Steam quality:

- **Higher steam quality results in higher & faster recovery (fig.11.7).**
- **Some investigators had discovered an optimum steam quality for max. oil recovery on a net heat injected (40% steam quality)**
- **On increasing steam quality, steam volume increases where as steam viscosity decreases.**
- **Higher steam volume results in greater volumetric contact with the oil, where as lower steam viscosity results in poorer displacement and sweep efficiencies due to a poorer mobility ratio.**

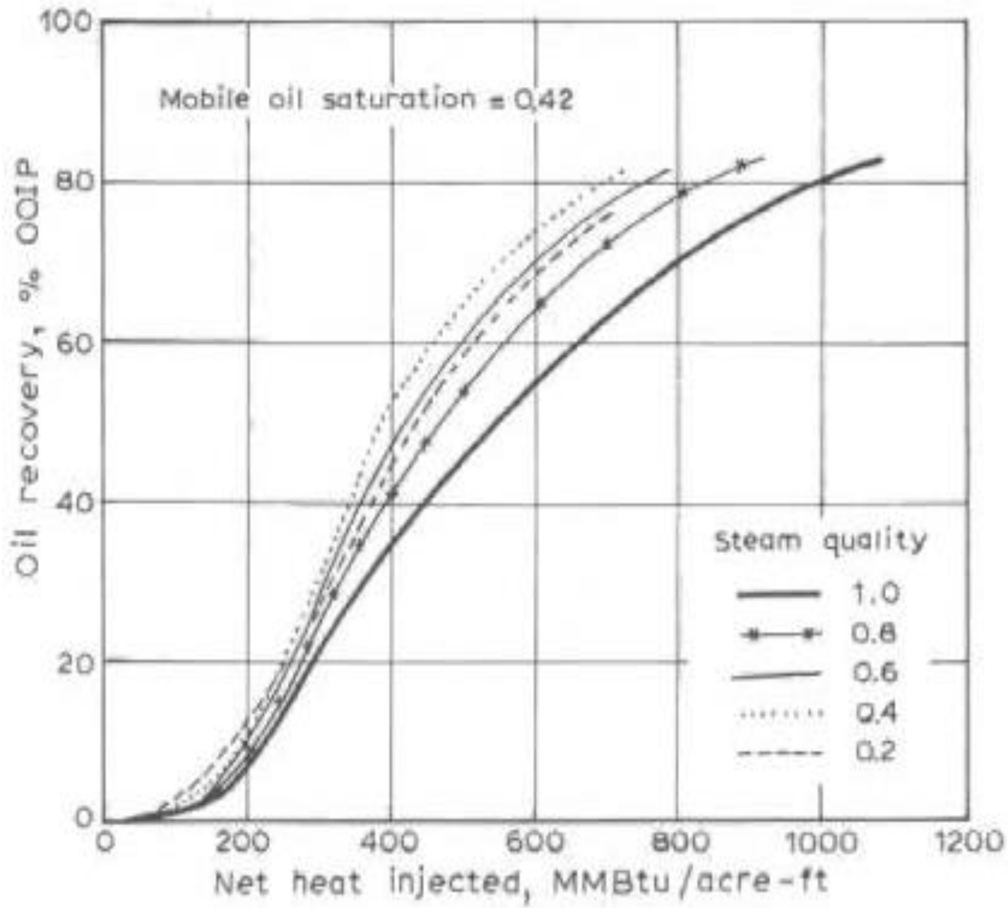

Fig. 11-7. Effect of steam quality on steamflood oil recovery. (After

ECONOMICS OF THE STEAM FLOODING PROCESS:

Apart from the technical criteria discussed earlier, certain economic criteria that must be considered are described in this section.

Profitability

Steamflood profitability depends mainly upon the steam/oil ratio (*SOR*) during the project. The ultimate *SOR* from a steamflood can roughly be predicted by the following equation given by Neuman (1975):

$$SOR = \frac{1}{2.7\phi(S_{oi} - S_{ors})f_{sdh}} \tag{11-50}$$

where ϕ is the formation porosity, fraction: S_{oi} is the initial oil saturation (when steamflooding is initiated), fraction; S_{ors} is the residual oil saturation in the steam zone, fraction; and f_{sdh} is the downhole steam quality, fraction. Empirical equations by Chu (1985) may also be used; for $SOR > 5.0$:

$$(SOR)^{-1} = -0.011253 + 0.00002779D + 0.0001579h - 0.001357\theta$$
$$+ 0.000007232\mu + 0.00001043(kh/\mu) + 0.5120\phi S_o \quad (11\text{-}51)$$

and for $SOR \leqslant 5.0$:

$$SOR = 18.744 + 0.001453D - 0.05088h - 0.0008864k$$
$$- 0.0005915\mu - 0.0002938(kh/\mu) - 14.79S_o \quad (11\text{-}52)$$

where θ is the angle of dip in degrees.

The incremental cost per barrel of oil, ICBO, is approximately equal to:

$$\text{ICBO} = SOR(C_s I_w + N_w C_{lw})/I_w \quad (11\text{-}53)$$

where C_s is the steam cost, \$/bbl steam; I_w is the steam injection rate, bbl/day water equivalent; N_w is the number of producing wells; and C_{lw} is the combined lease and well cost, U.S.\$/producing well/day.

Total cost of produced oil

The total cost of produced oil, TCPB, can be estimated as follows:

$$\mathrm{TCPB} = \mathrm{ICBO} + (SOR\ I_{ic})/(I_w t^*) \tag{11-55}$$

where I_{ic} is the investment cost, U.S.\$.

Optimum steam injection rate

It is not possible to derive a general equation for estimating the optimum steam injection rate, because there is no good way to predict what fraction of usable heat will be produced. Neuman (1975), however, has given an equation for estimating the optimum injection rate, $(I_w)_{opt}$, provided the rate of oil displacement, Q_o, is known:

$$(I_w)_{opt} = \frac{Q_o}{2.7\phi(S_{oi} - S_{ors}) f_{sdh}} \tag{11-56}$$

The areal coverage of steam, A, can be calculated if the injection rate of steam is known:

$$A = \frac{6.1 I_w L_v t^{1/2}}{(2K/f_{sdh})\, \Delta T (L_v + c_w\, \Delta T)} \tag{11-57}$$

Equation (11-57) can also be used to estimate the injection rate that will give a complete areal coverage in a given time.

Well Spacing:

- Well spacing is another factor that is critical to the performance as well as the economics of any EOR project.
- When a field is developed, the wells are drilled in such a way as to be suitable for secondary and tertiary recovery operations.
- A definite mathematical relationship exists between increased recovery and closer spacing; recovery is inversely proportional to the square root of the well density expressed in acres per well.
- In choosing well spacing, reservoir characteristics such as depth, K, ϕ, should be taken into consideration. If the reservoir is shallow and massive, closer spacing is generally adopted.
- If the spacing is closer, interference may occur which may cause breakthrough of the injected fluid.
- It may not be economically feasible to drill many wells if the reservoir is at a greater depth. So well spacing depends upon reservoir characteristics as well as economics.
- Generally steam injection projects have a well spacing of 3-6 acres.

SUMMARY

Steamflooding is an important and economically efficient enhanced recovery process for heavy, viscous crudes, as proven in fields worldwide. The chances of success are very great under the following conditions:

(1) The crude in situ has a gravity of 10–36° API, with a viscosity around 1000 cP.

(2) The oil-in-place in the reservoir is at least 1200 bbl/acre-ft, with an average oil saturation in excess of 40%, and reservoir porosity greater than 20%.

(3) The reservoir depth is less than 5000 ft.

(4) Reservoir injectivity is high enough to permit steam injection.

(5) The formation pressure and reservoir productivity are sufficient to ensure at least moderate production rates.

(6) Reservoir pressure and temperature are such that an optimum steam temperature of 300–400°F can be maintained.

OPERATIONAL ASPECTS OF STEAM INJECTION PROCESSES

INTRODUCTION:

- It starts by considering the treatment of the water used to generate steam, and follows the steam as it enters the reservoir.
- A schematic diagram for the flow of the injected water and the produced fluids is shown in fig.12.1.
- Equipment related to thermal operations is also discussed.
- Well completion design as per requirement continuous steam injection/ cyclic steam injection and their regular maintenance.
- Permanent or centralized steam generator facilities are generally preferred in steam drive operations on techno economic basis.

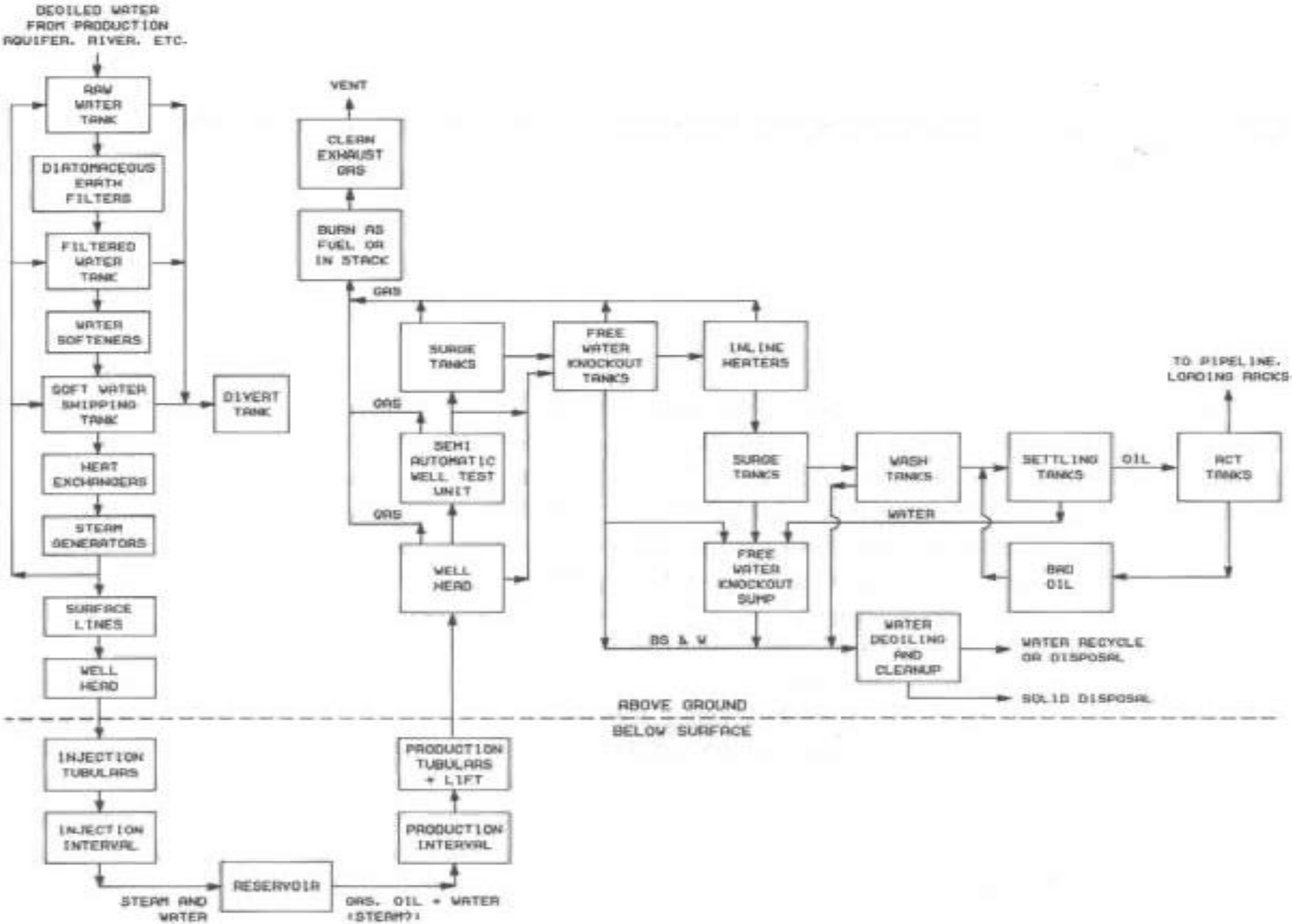

Fig. 12-1. Schematic flow diagram for water in steam injection operations. (After Prats, 1982, p. 138,

WATER TREATMENT FOR STEAM GENERATION (SG):

- Steam generation requires clean water,
  1. it should not contain suspended solids (SS),
  2. the dissolved minerals, liquids & gases must not be harmful to the SG equipment, steam distribution system & wells.
- SS tend to foul the water softeners & promote the formation of sludge, which leads to reduce the injectivity of the well.
- Oil in the feed water reduces resin life, which promotes scaling in tubes, which leads to reduce the heat transfer rates, causes overheating and corrosion problems.
- Produced water contains increased hardness, dissolved solids, high salinity, oil content, is to be treated suiting for SG.
- It is generally appropriate to consider the following procedures applied,
  1. Use of bactericide, usually chlorine or formaldehyde is used.
  2. Filtering out the SS & bacterial debris. The levels of SS in the filtered water should be below 5 ppm or lower.
  3. Removing dissolved O_2 by adding catalyzed sodium sulfite or by stripping it with sweet natural gas or steam. ($O_2 < 0.01$ ppm)

4. **Controlling scale-forming ions such as Ca, Mg, Fe to less than 1 ppm of total hardness. Ca, Mg are removed by ion-exchange methods. A scale inhibitor is used as an additional precaution. TDS should be maintained at levels where they will not precipitate.**
5. **Removing oil from produced waters by a combination settling tanks, basins, flotation cells, & diatomaceous earth filters (< 1 ppm).**
6. **Ascertaining that the pH of the feed water is in the range of 7-12. A pH below 7 suggests the acidic corrosion of the pipes. (Fe < 1 ppm)**

- **The storage tank preferably should be galvanized and have a nitrogen blanket to reduce iron pickup and dissolved oxygen respectively.**

STEAM GENERATORS: Type of steam generators:

- **Steam generators used in oilfields differ significantly from conventional boilers. Conventional boilers are generally used to generate saturated & even super heated steam to drive impellers.**
- **Superheated steam can be used to avoid liquid-vapor separation. The condensed steam is collected down stream of the impellers for reuse requiring little makeup water. Once the initial inventory of water is treated, additional treating costs are limited to the makeup water.**

STEAM GENERATORS: Type of steam generators: (continued)

- On the other hand, oilfield operations require large quantities of steam for continued and long term injection into reservoirs.
- Inasmuch as there is essentially no steam condensate available for reuse, this requires that the cost of treating water be relatively low.
- Single-phase type, also known as wet-steam generators, are used almost exclusively in the oilfields. (don’t require recirculation and blowdown & steam quality limited to about 80% to avoid deposition)
- There are indirectly-heated generators, that use unsoftened or produced water as feed.
- All field steam generators today are fired with natural gas, oil or coal.
- Fig.12.4 is a typical unit, where as fig.12.5 is a schematic representation of an oil-fired, once through steam generator.
- Treated water is delivered to the generator at the pr necessary to inject the steam into the wells by the feed pump, at a constant rate.

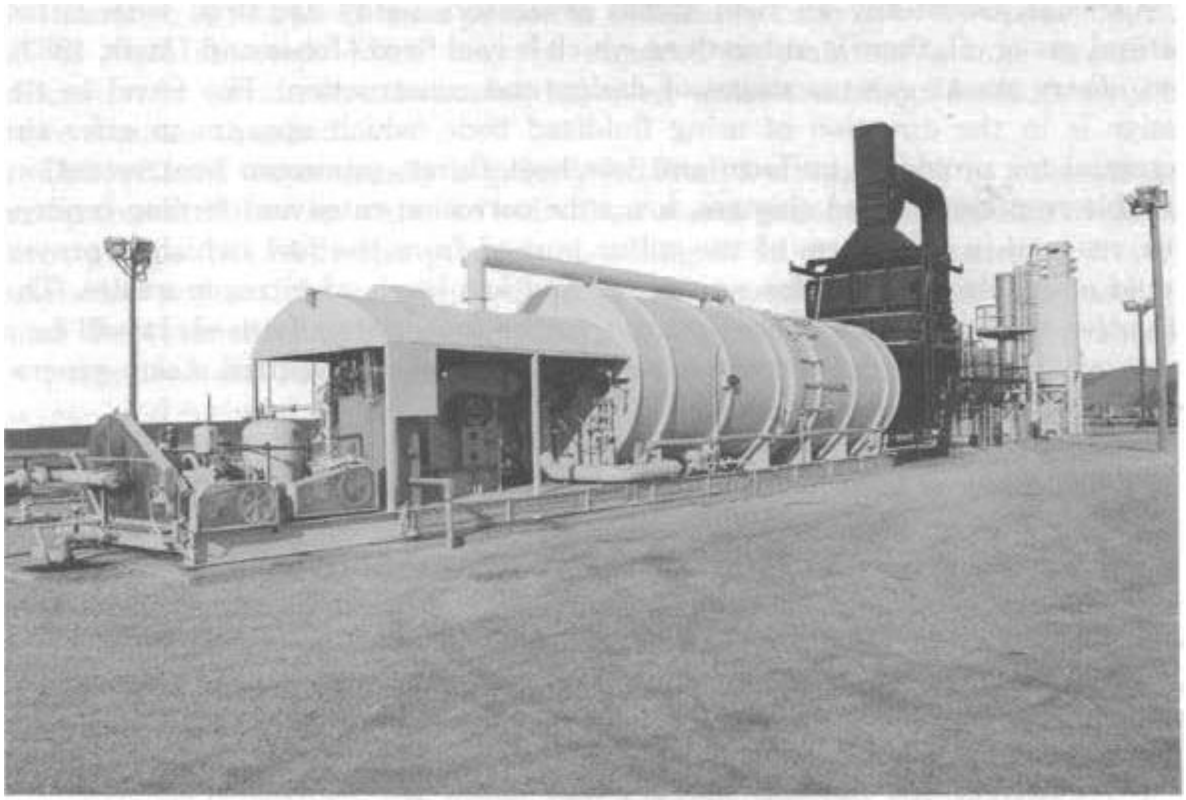

Fig. 12-4. A typical steam generator. (Courtesy of Struthers Thermo-Flood Corporation.)

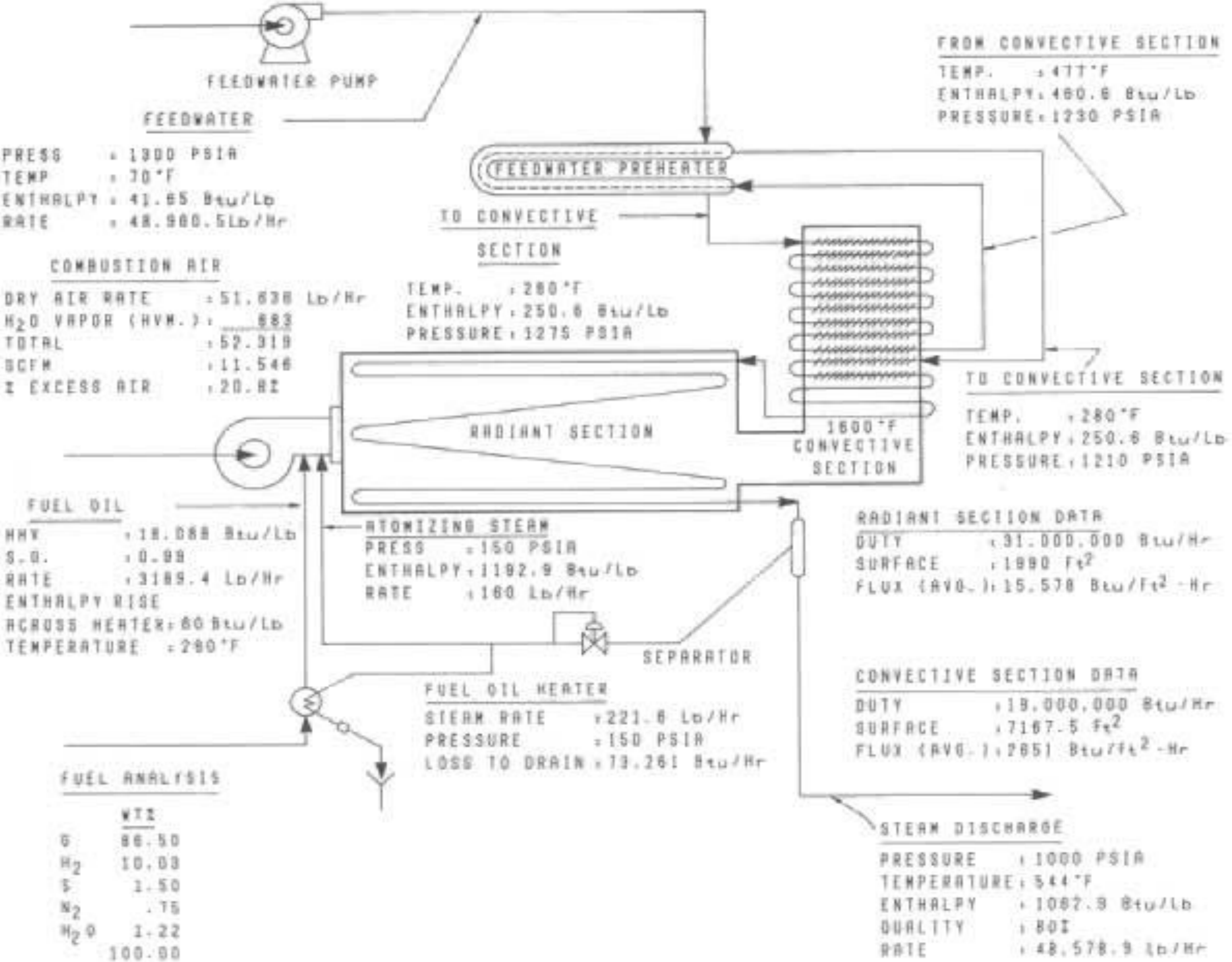

Fig. 12-5. Process flow diagram and thermodynamic heat balance for a 50×10^7-Btu/hr steam

Efficiency of steam generators:

- Typical efficiencies of steam generators are about 80-85% & can exceed 90% with special equipment design. Most of the lost heat goes through the stack. The amount of heat lost via stack gases is directly proportional to the temp & mass flow rate of the vented gas.
- Special alloys are being used in the stack section to withstand corrosion, thus allowing a higher thermal efficiency.

Sizing steam generators:

- Steam generators are generally available at 3 nominal coil pr ratings: 1000, 1500, & 2500 psig. For pr ratings of 2700-2800 psig, molybdenum steels are used which are required for higher pressures.
- Typical capacities of steam generators range from $10X10^6$ to $150X10^6$ Btu/hr corresponding to rates about 650 and 10,000 BWPD (barrels of feed water per day) converted to 80% quality steam.
- In small projects, consideration should always be given to have two or more steam generators instead of one of equivalent capacity. This increases the reliability of the steam for the EOR operation.

Scrubbers:

- The low levels of sulfur emission rates are attained by passing the stack gas through scrubbers. Components in scrubbing units my be of the dry or wet type, but most scrubbing units are made of wet components.
- The SO_2 is removed from the stack gas by absorbing and reacting it in an alkaline solution. Different types of wet components are used in scrubbers: tray towers, packed towers, spray towers & ejector venturi.
- Most of the scrubbers in current use in oilfields are made up of two or more of these components.

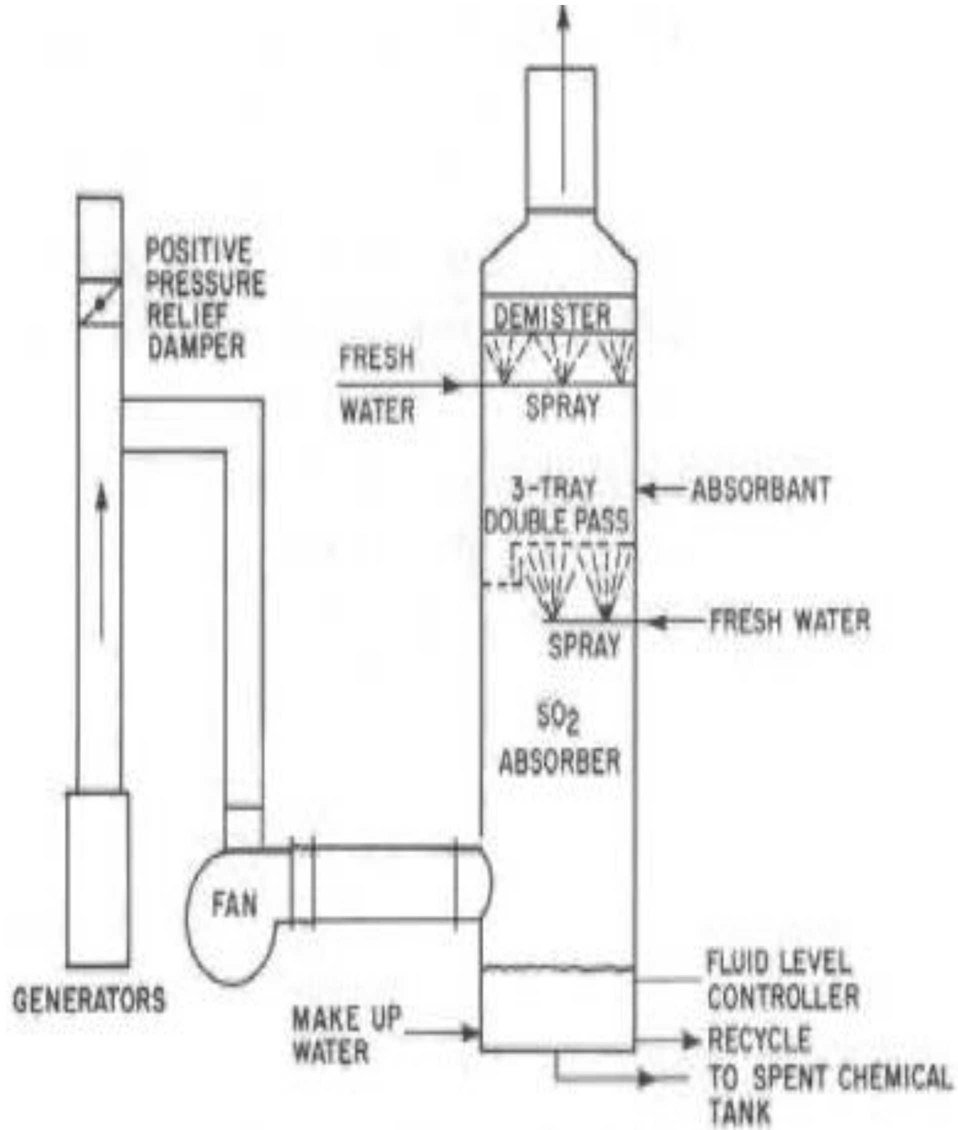

Fig. 12-7. Schematic diagram of typical scrubbing unit (based on

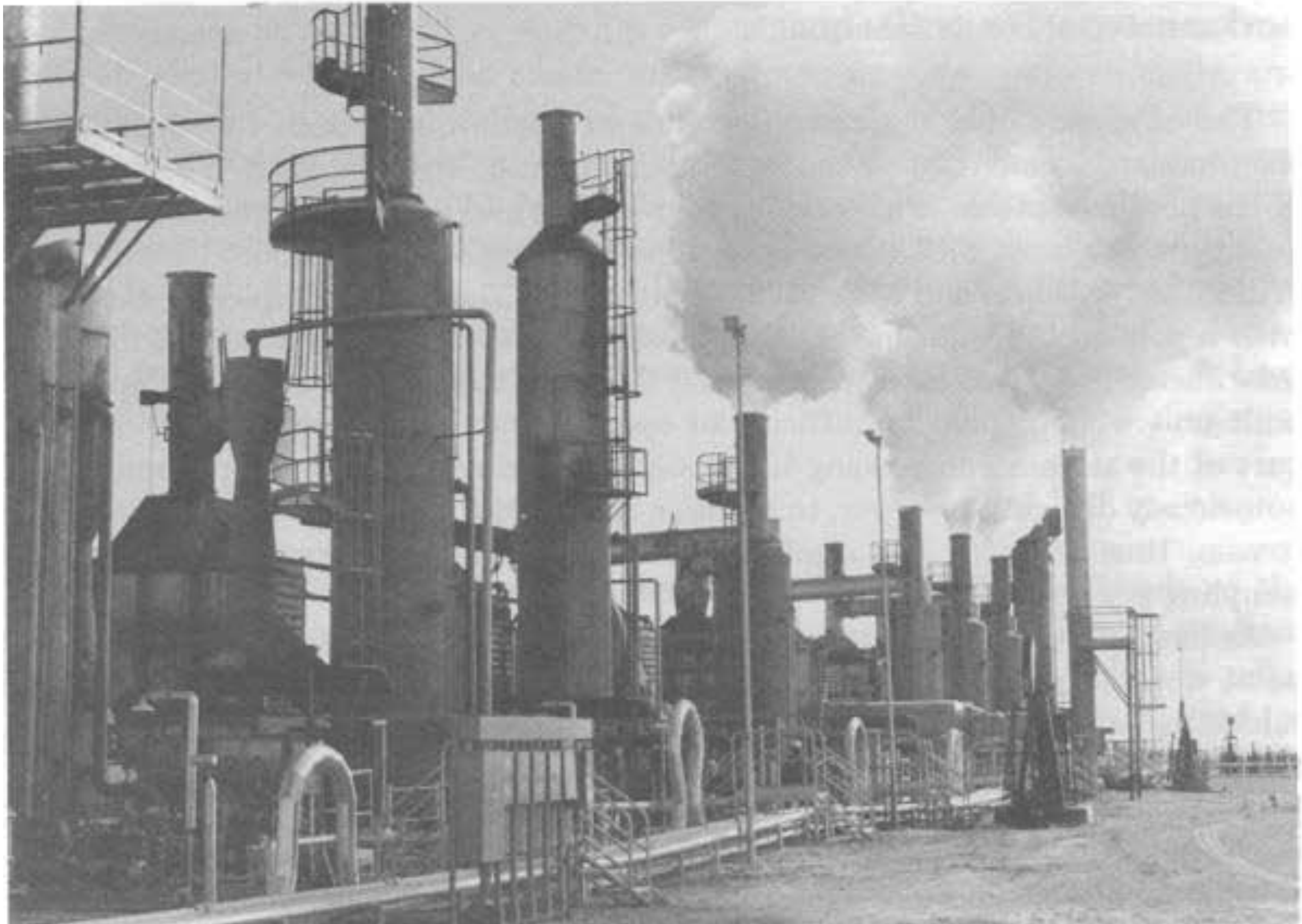

Fig. 12-10. Installed scrubbers. A cloud of clean steam effluent is typical—there are no pollutants in the steam. (Courtesy of Struthers Thermo-Flood Corporation.)

DETERMINATION OF STEAM QUALITY:

- The efficiency of a generator is commonly determined from the enthalpy of the produced steam relative to the total energy used to it.
- The enthalpy of the produced steam is affected by its pr & quality. Of these, the steam quality is the most difficult to determine accurately.
- Enthalpies could be measured with a condensing calorimeter through which passing the entire steam is seldom attempted in the field.
- It is also difficult to get representative sample of the steam to measure the quality through this calorimeter.
- The steam quality is given by the square of the ratio of the apparent mass flow rate through the orifice meter (assuming 100% steam vapor).

Surface lines:

- Steam distribution lines from the steam generators to the wellheads of the injectors are at higher prs (below 1500 psi) & temps than those from the production wells to the separation facilities.
- Heat losses from the surface steam lines can be reduced by insulation which also in turn reduce fuel costs & as a safety precaution. When un-insulated lines are buried, it is often advisable to lay them in a sandfilled large diameter conduit pipe to reduce excessive heat losses.

WELLS: Casing design considerations:

- Well designs: Effect of temps on thermal stresses in the casing
- The injection or production of hot fluids can be interrupted by
  1. Mechanical failures (burn-outs of tubings or disruptions in fuel supply of steam generators)
  2. Workovers to restore injectivity or productivity
- If the shut down (s/d) of the hot fluid injection period is long, the wellbore temps will fall, leading to tensile casing stresses.
- WOR almost will be needed to correct impairment or mechanical failures.
- Casing tends to elongate when heated. For casing cemented on bottom only, buckling is almost inevitable in the unsupported sections of any significant length unless casing is free to expand through a packing gland at the surface pipe.
- The compressive casing stress does not exceed its yield strength to prevent joint pullout. In new completions, this can be done by selecting suitable combination of materials but in existing wells only temp can be controlled.
- In shallow reservoirs steam injected directly down the casing. Fig.12.12 shows, 500' deep (steam temps are low), 7" casing, 22 ppf, K-55, or 5", 14 ppf K-55 casing are used with class G cement modified with Perlite, silica flour & $CaCl_2$ which are used to reduce the loss of cement strength at high temp.

TABLE 12-I

Temperature changes and tensile forces resulting from cooled pipe (after Willhite and Dietrich, 1967 p. 17, table 2; courtesy of the Society of Petroleum Engineers of AIME)

Casing temperature (°F)	ΔT_{max} (°F)	ΔT_{yp} (°F)	ΔT_{te} (°F)	Tension when cool, (psi)	Remarks
500	400	275	125	25,000	no failure
550	450	275	125	35,000	no failure
600	500	275	225	45,000	failure
650	550	275	275	55,000	failure

TABLE 12-II

Allowable temperature changes for buckling and compressive loading (after Willhite and 1967, p. 16, table 1; courtesy of the Society of Petroleum Engineers of AIME)

Material grade	Minimum yield stress (psi)	Allowable temperature change (ΔT, °F)	
		buckling [a]	uniform loading
J	55,000	237	275
N	80,000	346	400
S	95,000	410	475

[a] 7-inch, 23-lbm/ft, 30-ft long joint with 1/2-inch radial clearance.

WELLS: Casing design considerations: (Continued)

- Steam is seldom injected directly down the casing in deep wells.
- Casing temps can be reduced below that of the injected steam by injecting the steam through tubing & by keeping the steam from casing-tubing annulus.
- This serves not only to reduce the likelihood of well failure but also to reduce heat losses to reservoir.
- Thermal packers are commonly used to keep the steam from the tubing -casing annulus.
- Another alternative is to inject inert gas down the annulus at low rates while steam is injected through the tubing.

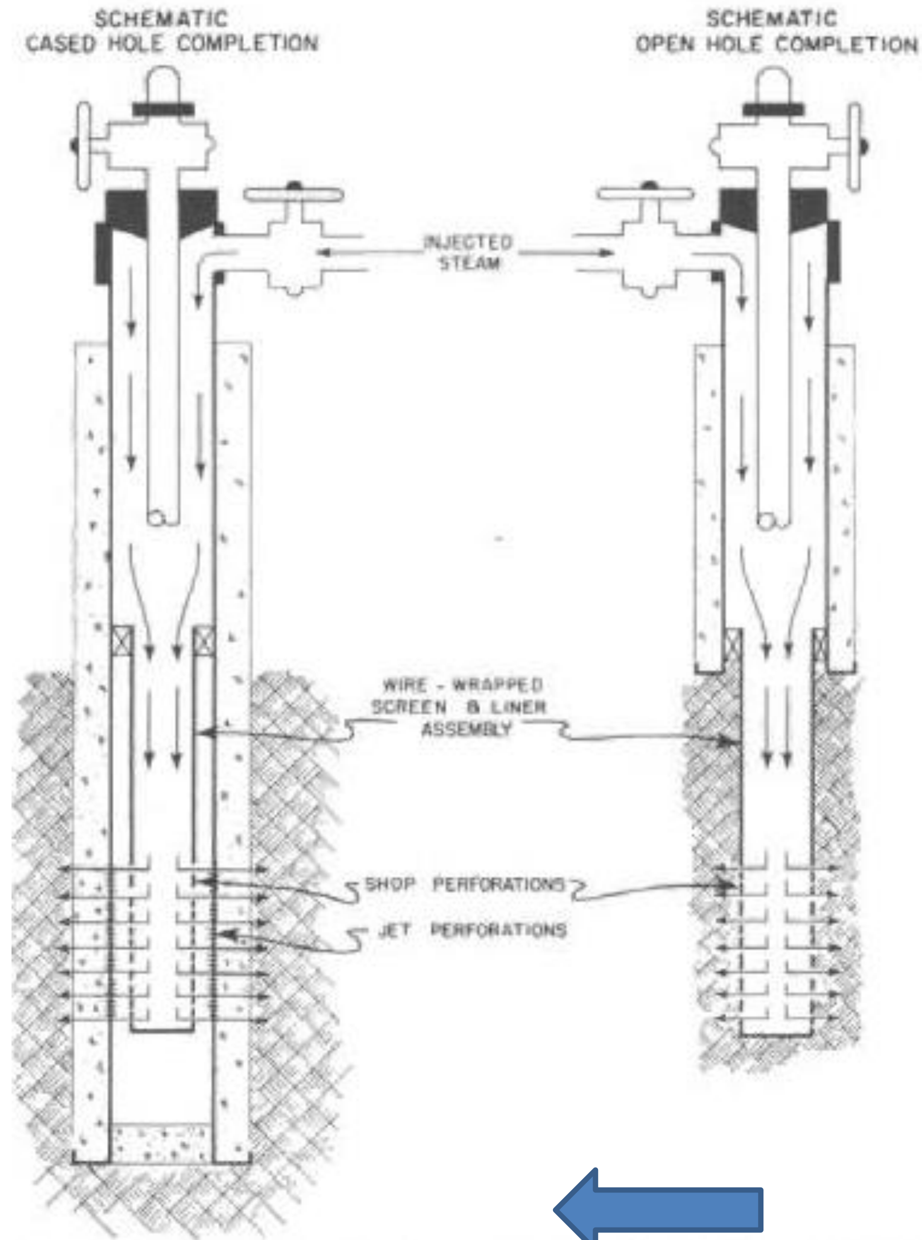

Fig. 12-12. Schematics of well completions in the Slocum Field. (

Tubing strings: A well design using a small gas flow in the tubing-casing annulus to insulate the casing is shown in Fig.12.13. No packer is used & the gas enters the formation along with the steam.

- The casing completion is designed for a high-temp (about 645^0F) steam drive operation in which the process calls for large reductions in temp of the injected steam.
  1. The casing is designed for direct exposure to the high-temp steam
  2. Both the casing & its connections have been selected to withstand the loads resulting from the expected temp variations,
  3. Additional precautions have been taken to reduce temp on the casing by insulating the tubing & by injecting gas at a low rate in between down the annulus.
- A bottomhole pr sensor strapped to the tubing, & of centralizers& expansion joints a selectively perforated casing for steam injection into the formation.

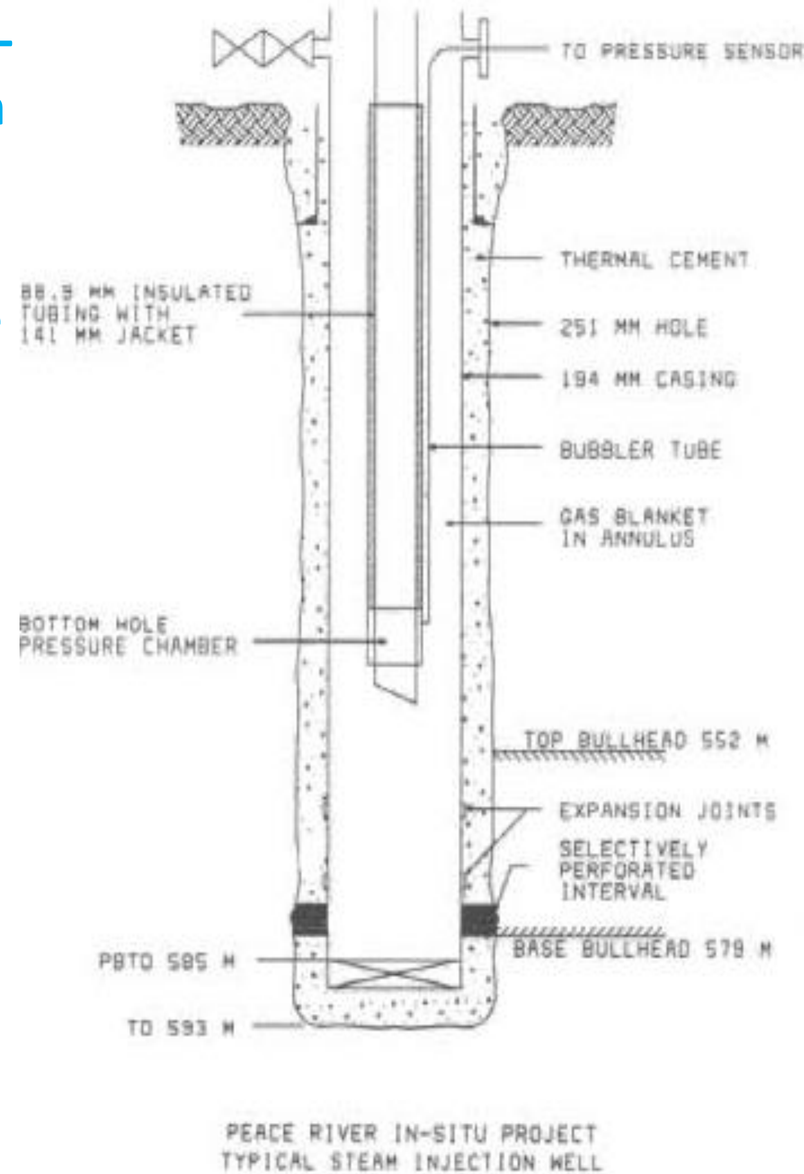

Fig. 12-13. Schematic of a typical injection well completed

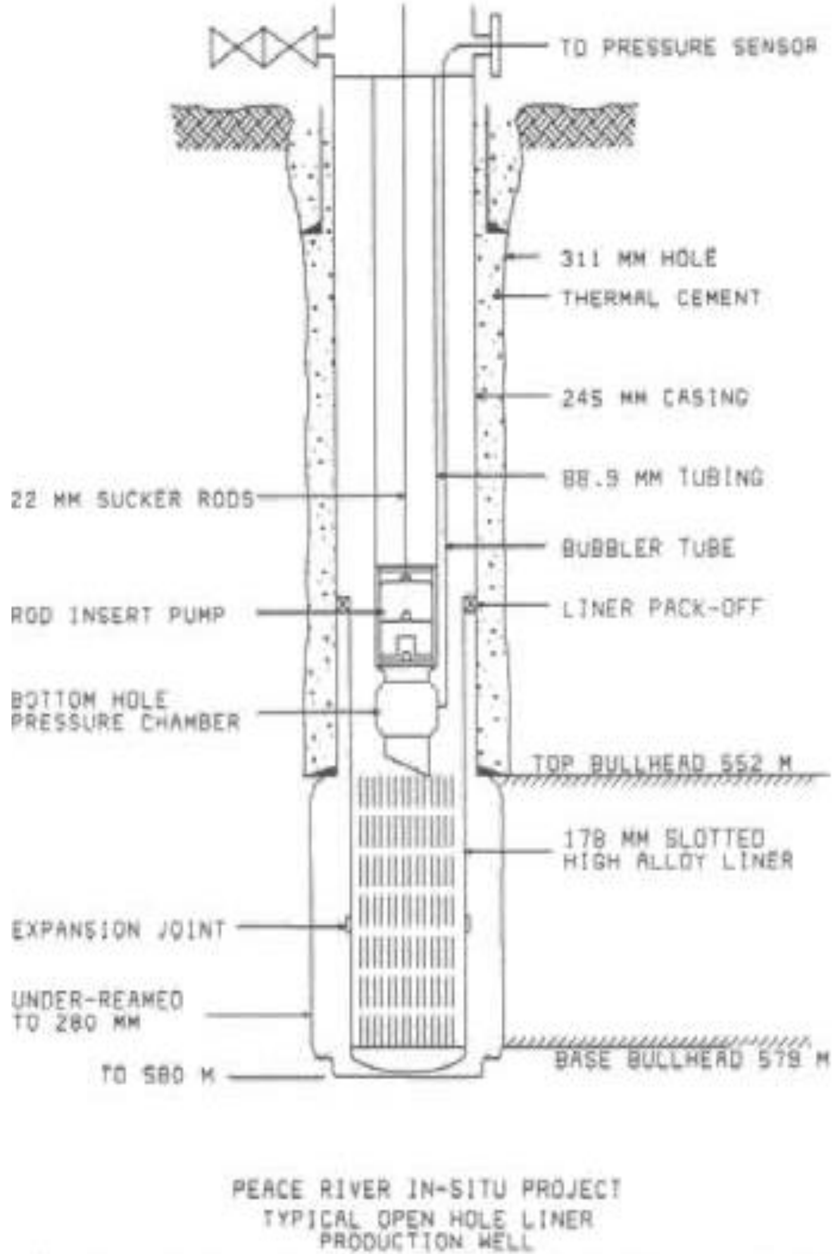

Fig. 12-14. Schematic of a typical openhole liner production well

Fig. 12.15 shows an openhole gravel pack completion with a high alloy liner, where as Fig. 12.16 shows a cased & perforated high alloy liner completion as required.

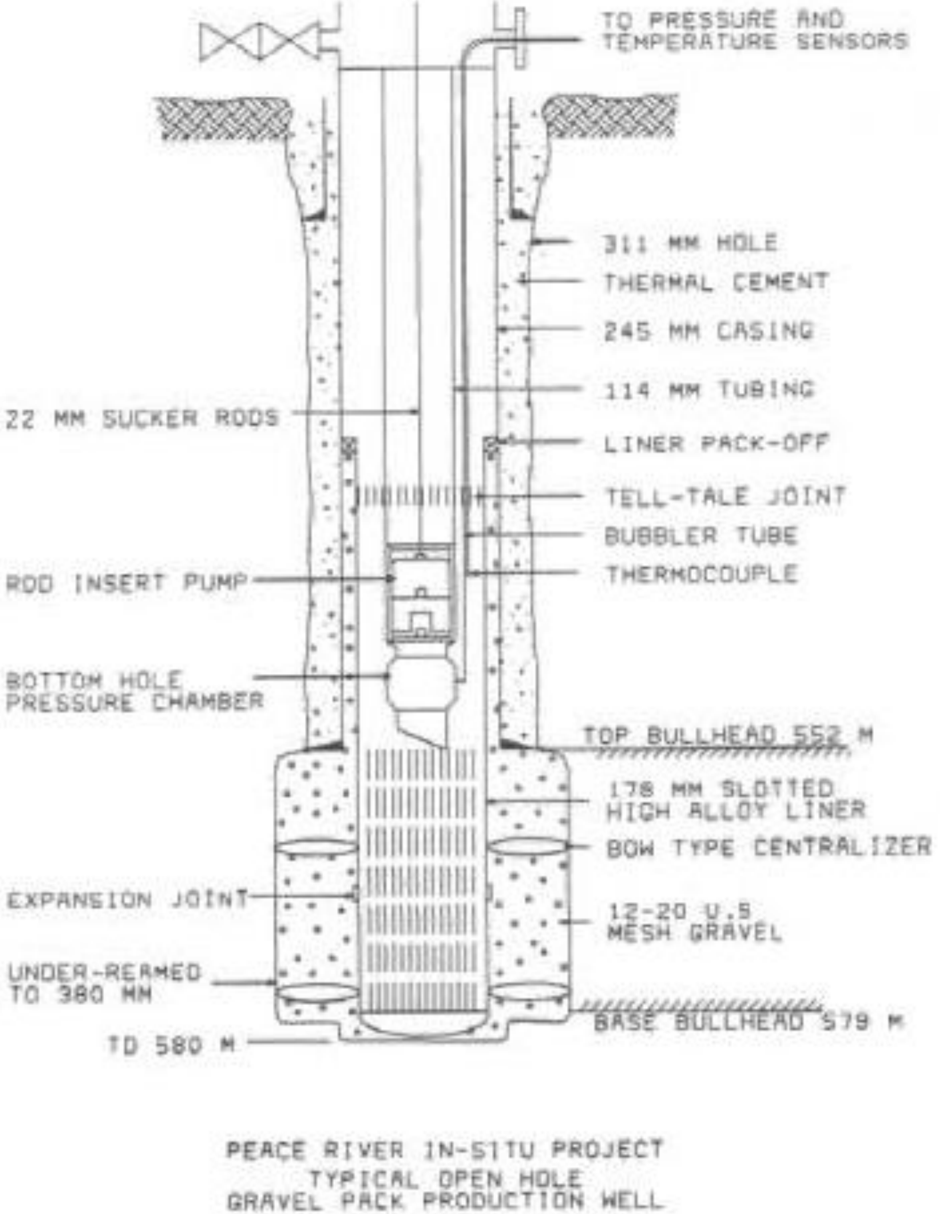

Fig. 12-15. Schematic of a typical openhole gravel pack prod

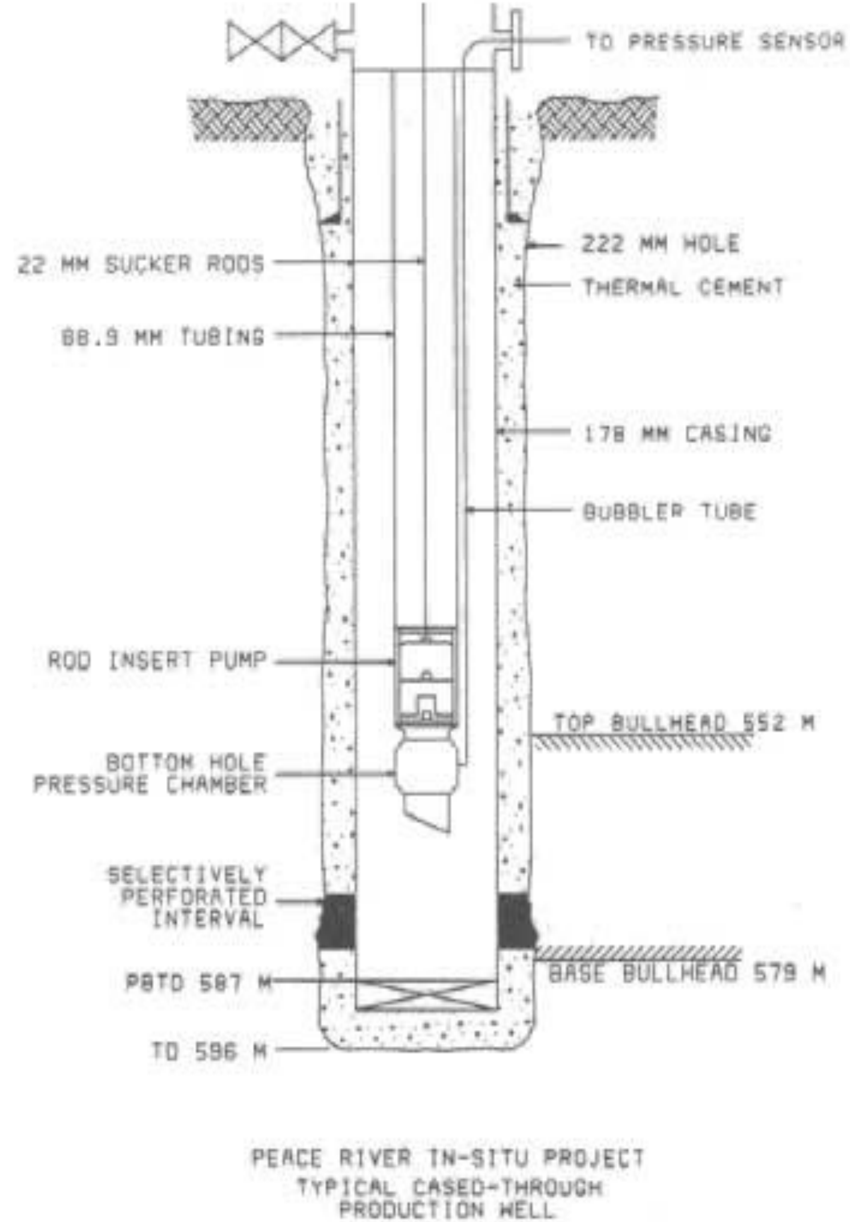

Fig. 12-16. Schematic of a typical cased-through production well

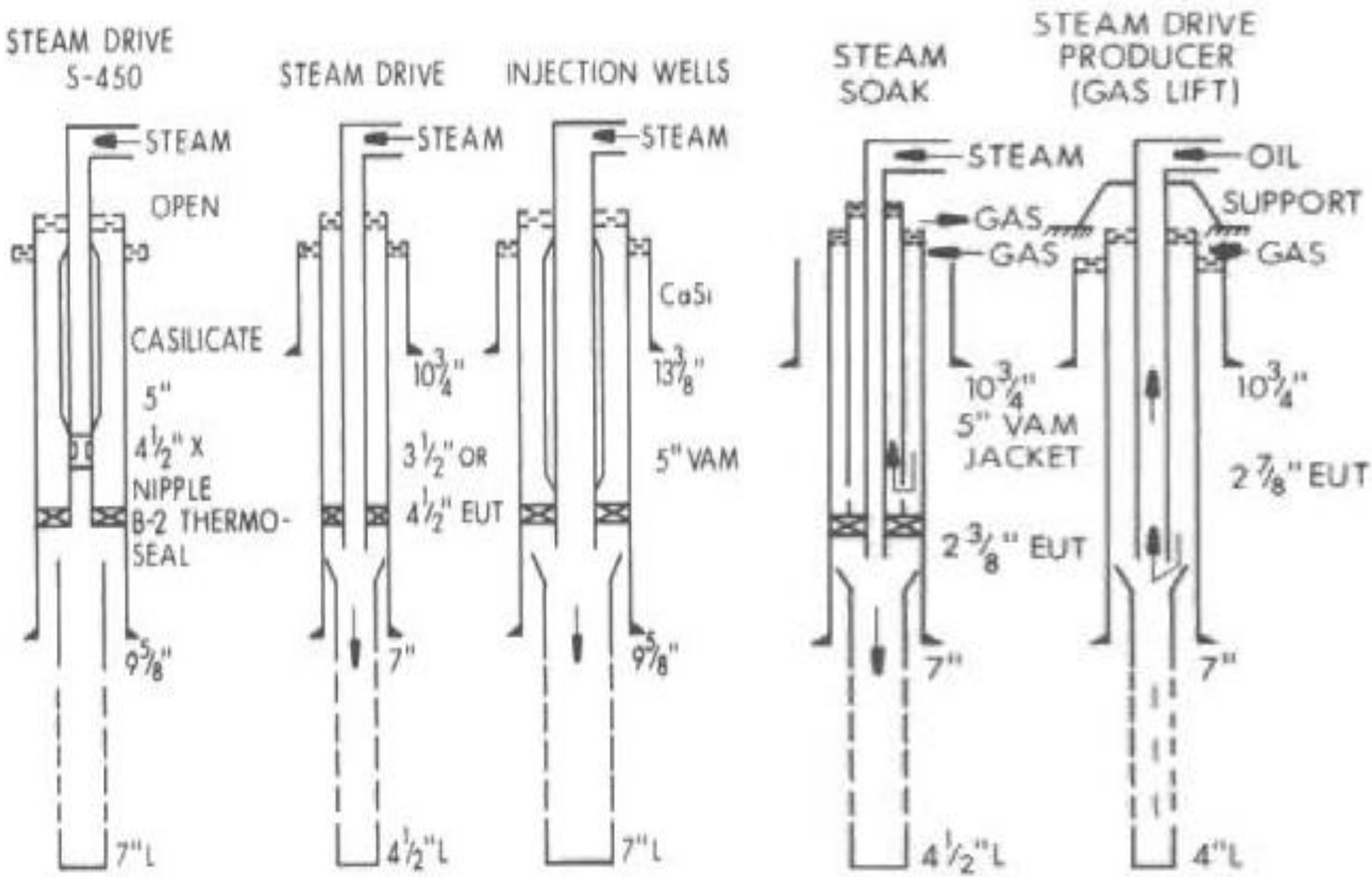

Fig. 12-17. Schematics of well completions in the Schoonebeek Field.

- All injection wells shown in fig.12.17 have tubing connected rigidly to the casing at the thermal packer.
- Tubing expansion on heating is accommodated by allowing the tubing to slip through a stuffing box at the wellhead.
- At the present time, it is far more common to hang the injection tubing from the wellhead, allowing to expand downward into the wellbore as it heats, as shown schematically in figs. 12.12 to 12.16

Cementing: Cementing thermal wells differs from that in conventional wells in the following aspects.

1. Cement should be circulated to the surface on every string of casing. The objective is to provide a complete fillup of cement in the casing hole annulus to anchor the casing firmly to the ground through the cement sheath, thus reducing buckling and casing creep.

   Also, the hardened cement sheath should protect the casing against corrosion and prevent the uncontrolled flow of hot fluids outside the casing (230^{0}F)
2. API Class G or H cement should be used with at least 30% silica flour. Retarders, friction reducers and additives to control lost circulation. Bentonite, Perlite are used to reduce the slurry density.

Cementing (Continued)

3. The following cementing practices are to be adopted for good results.
   a) Estimating the amount of cement slurry required.
   b) Estimating the times to run the casing and circulate the cement to surface;
   c) To take the decision to reciprocate & or rotate the casing while cementing.
   d) To determine the need for mud thinners, preflushes, centralizers, scratchers and floating equipment. These practices are more important at high temps.

PRODUCTION FACILITIES:

Lifting:

- To promote the desired reservoir response, a low wellbore pr is to be maintained to increase the pr difference available from the reservoir.
- For heavy crudes, lifting problems normally fall in 3 categories.
  1. The crude oil is very viscous,
  2. The temperatures are very high,
  3. There is sand problems.
- The performance of subsurface sucker rod pumps are better to lift the fluids in steam injection operations.
- When the crude oil is highly viscous, the rod pump could not work properly which lead to rod stuck up situation.
- A common solution to this problem is to inject a diluents through annulus which makes the rod to move freely.
- Rod fall also has been improved by lifting through the annulus, with the rods in the tubing being in contact with water under pressure.

Well completion with SRP

- A downhole stuffing box just above the perforated tubing nipple isolates the tubing fluids, illustrated in fig.12.20
- Pumps may perform poorly at elevated temps causing vapor lock.
- The remedies are few:
  1. Shutting in the well & allowing it to cool so that it can be produced intermittently;
  2. Increasing the back pr on the well to make flashing less likely; and
  3. Adding a liquid (through the annulus, hallow sucker rods, or a separate string) to reduce the downhole temp.
- None of these methods is efficient. The production rates mostly will come down. Adding coolants , of which water is the most cost-effective.

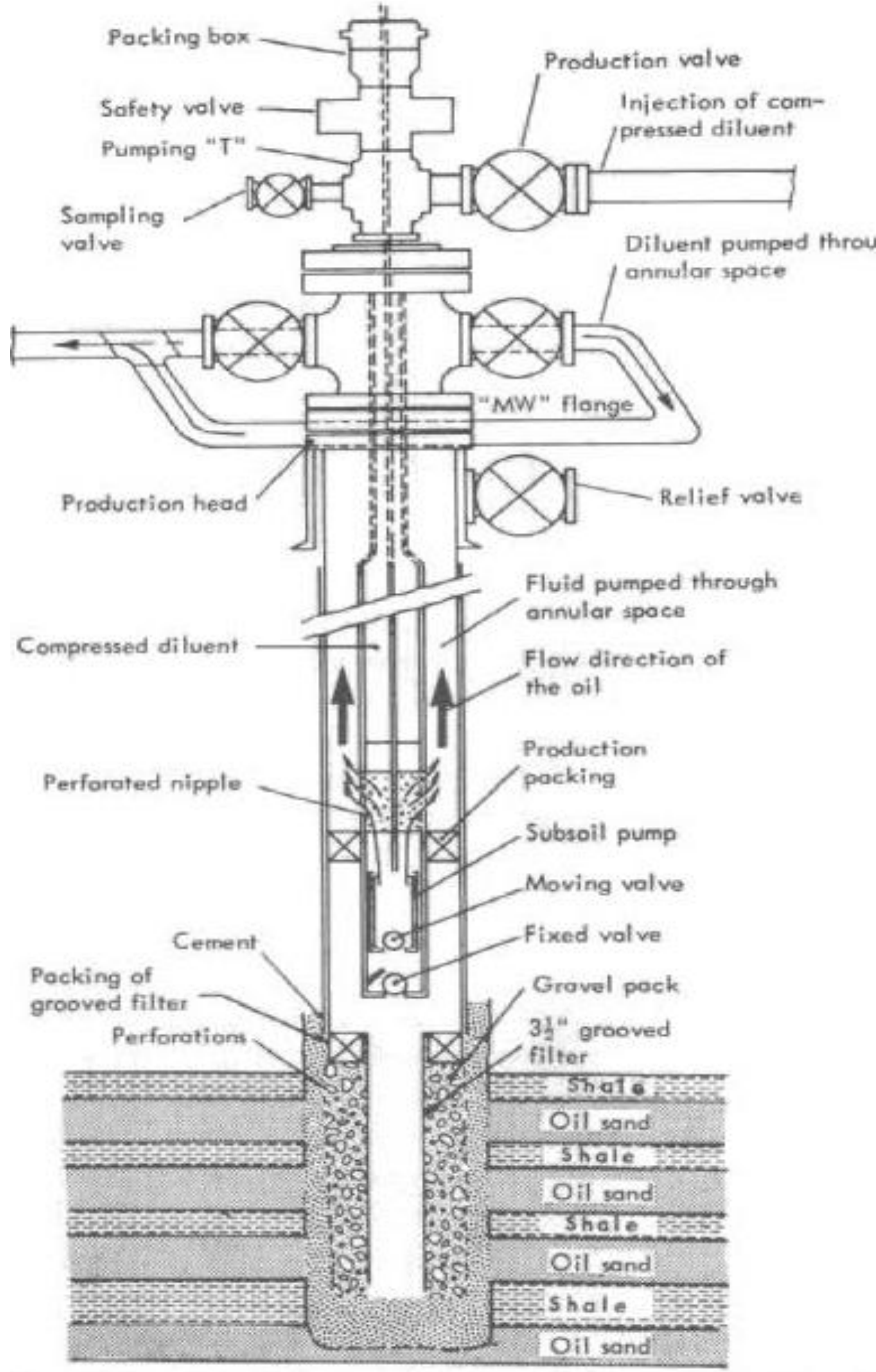

Fig. 12-20. Jobo Field—typical well completion. (After Ballard

MOVING THE CRUDE OIL FROM THE FIELD:

- Crude oil is normally pipelined from the field to the refinery. The crude oil leaving the separators is still hot, normally no problems in transferring the heated crude to nearby oil terminals through a ACTU (automatic custody transfer units).
- When the crude oil is extremely viscous, pour point is very high, the ambient surface temps are low, or the distances to terminal are long.
  1. The crude is piped as a core surrounded by a water lining between it and the wall– the water acts as a low-viscosity lubricating film.
  2. The carrier operator has to add a diluent, normally light crude oil.
  3. To heat its pipe line through some line heaters.

DISPOSAL:

- As in any oilfield operation, solids, water, and gases must be disposed of properly. Solids, which usually are contaminated with oil, include sand & silt particles, inorganic scales, rust & metal-organic compounds.
- The treatment of the effluents varies from one location to another, reflecting the variability of the problem, legal requirements, and local practices .

DISPOSAL (continued):

- For gases, condensation, incineration & scrubbing are the usual procedures. Condensation may be cost effective where there are enough recoverable hc liquids. Incineration is used to convert H_2S to SO_2, as well as to burn the hc gases.
- The methods of waste water treatment depends on the type and conc. of the contaminants & ultimate disposition of the water, whether to the surface or the subsurface.
- Solids are usually disposed of as per the norms prescribed by SPCBs.

SPECIAL SITUATIONS: Offshore operations:

- The well tubings must be better insulated than normal for steam injection projects from offshore platforms as heat losses are relatively large.
- The main problems appear to be related to the limited space on the platform in which the facilities must be located.

Compacting reservoirs: Compacting reservoirs provide additional energy to produce the oil heated by the steam where cyclic steam injection remains attractive. In addition to these problems, possible subsidence & changes in the surface drainage patterns, compacting reservoirs have higher incidence of well failures, tubulars are required to be replaced very early.

OPERATIONS:

- The main responsibility of field & office operation personnel is to ensure that field operation is to running smoothly & on target.
- It requires that the production be maintained at the highest possible levels for the manpower & resources available.
- Resources are adjusted to meet the project goals at highest degree of safety in all operations.