FINAL

INJECTION WELL CONSTRUCTION PRACTICES AND TECHNOLOGY

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PREFACE

This document describes construction practices and technologies related to Class I, Class II, and selected Class III and Class V injection wells as defined by the U. S. Environmental Protection Agency. Topics covered include siting, drilling, completion, equipment and materials, corrosion control, well evaluation/logging, and formation testing. To avoid substantial repetition in the text, the basics of these topics are presented generically in Chapters 2 through 7.

The reader should note that the discussion of certain types of equipment, practices, or materials is not meant to infer their general usage in injection practices; rather, the document attempts to present state-of-the-art conditions in the topic areas as well as to provide a discussion of traditional practices where pertinent. Of necessity much of the information presented in this document is derived from the oil and gas production literature where the advanced technologies are being developed and used. In general, these oil-field practices and technology are adopted and modified as needed for use in Class I, Class III and Class V injection wells.

Class-specific, injection-well construction practices are highlighted in Chapters 8 through 10. In these chapters, specific construction practices and well designs are described for individual injection well applications. Discussions are intended to augment, where possible, the preceeding generic chapters. Design parameters critical to well integrity are emphasized in order to indicate problem areas potentially important to the regulator.

The level to which design discussions are presented will vary due to the state of technology development. Various Class III and Class V wells are in the research and development phase and little design data are, therefore, available; that information which is available is constantly changing with the technology development process. Even those technologies that are commericalized, such as uranium leaching, are not standardized as in petroleum operations and tend to develop on a trial and error basis.

Finally, this document is not intended to be a comprehensive "how-to" type treatment of injection-well construction, rather it is a reference material that describes the different aspects of design and construction of injection wells. Where required due to limits on size, information more directly related to well integrity, the major area of interest for the regulator, has been emphasized in the document. Extensive referencing is provided to effectively guide the reader to the accepted literature base when more detailed information is required. No attempt has been made to list all references available.

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1. INTRODUCTION

Sections 146.12, 146.22, and 146.32 of the Underground Injection Control (UIC) regulation provide the basic criteria to be considered when permitting injection wells. However, these basic criteria allow the Director to evaluate the construction features of existing and future injection wells with a degree of discretion. Accordingly, technical guidance is needed to assist the regulator's efforts to develop effective UIC programs and to implement and administer the UIC regulations. The purpose of this document is to assist in this need, by serving as a reference for injection-well planning and construction.

This document provides a discussion of traditional injection-well construction practices and technologies, and where applicable, the rationale for adopting and applying present technologies. Construction requirements in this document are broadly defined, and include: siting, drilling, completion, equipment and materials, corrosion control, and well evaluation/logging and formation testing. These topic areas are generically discussed in Chapters 2 through 7. In Chapters 8, 9, and 10, specific characteristics of Class I through Class III and Class V injection wells are discussed and specific examples are presented that illustrate these characteristics.

The basis of this document will be the review and analysis of existing sources of information concerning all aspects of injection-well design and construction. However, since the document is intended to assist in the permitting of injection wells so as to ensure the "prevention of movement of fluids into or between underground sources of drinking water," emphasis will be placed on citations related to achieving this purpose. Consequently, to the extent that the scope of this document is constrained by level of effort and length of presentation, information relating to issues peripheral to the protection of drinking water will be de-emphasized. Sources of information for this document include materials found in libraries of the American Petroleum Institute, U. S. Geological Survey

and the U.S. Environmental Protection Agency. Comprehensive computer literature searches were used to augment the library search in all areas of injection-well construction. In addition, experts in the field were contacted to assure that state-of-the-art information was collected.

1.1 RATIONALE FOR CONSTRUCTION REQUIREMENTS

As a result of growing concern over the contamination of the nation's ground-water resources, Congress has included in the Safe Drinking Water Act of 1979, a statutory mandate for the establishment of minimum requirements for effective State programs designed to protect underground sources of drinking water from subsurface injection of contaminants. The resultant UIC regulations are intended to broaden and strengthen these State programs as well as to establish minimum national requirements that reflect good engineering practice. It is also clear that many differences exist between States, including injection applications and geological conditions. For this reason, the regulations are designed to allow a State to exercise maximum flexibility in preventing contamination of drinking-water sources. Therefore, specific engineering practices or construction requirements are not in most cases rigidly specified. Rather, accepted engineering practices are described in order to provide the regulator with a framework to specify construction requirements on a case-by-case basis that should minimize the contamination potential. As a result, the list of construction requirements developed reflect the possible types of well or formation failures and the factors leading to their occurrence.

Injection well operation can lead to contamination of an underground source of drinking water (USDW) through: (1) escape of injected fluid through the borehole into a USDW as a result of insufficient casing, corrosion, or other failure of the injection well casing; (2) vertical escape of injected fluid outside the well casing from the injection zone into an USDW; (3) vertical escape of injected fluid from the injection zone through confining beds that are inadequate because of high primary permeability, solution channels, faults, or induced fractures; (4) vertical

escape of injected fluid from the injection zone through nearby wells that are improperly cemented or plugged or that have insufficient or corroded casing; and (5) lateral migration of injected fluid originally placed in a saline-water zone, into a fresh ground-water zone in the same aquifer as the injection interval. Indirect contamination of fresh ground-water can also occur when injected fluid displaces salty formation water vertically, causing it to flow upward into an USDW. The vertical flow of the saline water could be through paths of natural or induced permeability in confining beds or through inadequately cased wells drilled through the fresh-water/ salt-water interface.

In addition to these potential problems for failure, injection operations can hydraulically modify the injection interval and possibly the ground-water system and introduce into the subsurface, fluids that are different in chemical composition from that of the natural fluids. Impacts that could occur include: degradation of high-quality ground water; contamination of other resources, e.g., petroleum, coal, or chemical brines; stimulation of earthquakes; chemical reaction between injectant and natural water; and chemical reaction between injectant and geologic materials in the injection interval.

Because of the complexity of the construction process, the engineering principles related to the possible failure modes defined above are a concern of the regulator. The relationship of the principle failure modes of injection wells to the construction considerations listed in the regulations is presented in Table 1.1. These broadly defined construction considerations indicate various aspects of well design, construction, and operation that should be carefully evaluated to determine the potential for failure of an injection system in the UIC permitting process.

1.2 SUMMARY OF CHAPTERS

This document is organized into ten separate but inter-related chapters. Chapters 2 through 7 are a presentation of the basic practices, materials and technology of

TABLE 1.1

FACTORS CONSIDERED IN EVALUATING CONTAMINATION POTENTIAL

Contamination Mode	Construction Consideration
Migration through the borehole into fresh water aquifer.	Drilling
	Casing
	Cementing
	Well Equipment
	Logging
	Corrosion Control
	Testing/Monitoring
Vertical migration along the borehole.	Cementing
	Logging
	Well Equipment
Vertical migration through incompetent confining zones.	Siting
	Formation Evaluation
	Record Keeping
Vertical migration through nearby wells.	Area of review
	Monitoring
Lateral migration into a zone of fresh water.	Logging
	Monitoring

considerations for injection wells are presented in Chapters 8, 9, and 10. These chapters are intended to be a brief introduction to the well practices and cannot be an extensive discussion of each. For more information the regulator should familiarize himself with the vast literature base available.

Chapter 2, Injection Well Site Evaluation, describes site evaluation data, its acquisition, and use for typical Class I injection wells. Specific siting considerations for other injection wells, such as those covered in Class II, Class III, and Class V are described where pertinent in Chapters 9 and 10.

Site evaluation data discussed include information on rock types, structural geology, engineering properties of rocks, properties of subsurface fluids, and subsurface resources. These hydrologic and geologic data are first acquired from existing sources or surface geophysical surveys prior to drilling. If this data indicates a feasible site and construction is approved, additional data can be obtained during drilling and testing of the injection well. Actual data requirements will vary with the complexity of the geology, and the adequacy of existing information. Methods of data collection during and immediately after drilling include: coring and collection of cuttings, well logging, drill-stem testing, and injectivity or pump testing. Laboratory testing of formation fluids and the future injectant can also be done to obtain an indication of compatibility problems that could lead to formation plugging or dissolution.

Chapter 3, Drilling and Casing Methods, describes drilling methods, selection and installation of casing, and methods of cementing casing in the borehole. Special conditions or hazards encountered in these operations are also discussed.

Rotary, cable tool, reverse-rotary and other methods used for drilling injection wells are described. Hazards related to drilling operations include hole deviation, lost circulation, hole sloughing, and blowouts are discussed.

Casing selection considerations are described including setting depth, total diameter of the drilled well, formation temperature and pressure, and the volume and quality of injected fluid. The fundamentals of casing installation are discussed including hole preparation, casing make-up, running, and landing. The use of specific equipment such as float shoes, centralizers, and scratchers is covered. Selection of cement volume and mixture for use in the construction process is discussed including the use of additives and washing fluids. Both primary and secondary cementing techniques are described including the use of special equipment. Applications in extreme downhole environments are considered.

Chapter 4, Construction Materials, describes the basic materials used in well construction and their physical and corrosion resistance properties. The discussion includes casing and tubular goods, cements, cement additives, and related equipment used in well construction.

The physical properties of tubing are summarized including axial loading or compressive strength, internal pressure or burst strength, and external pressure or collapse strength. Also, the corrosion resistance properties of various metal alloys, fiberglass, plastic, and coatings used in tubular goods are described.

A wide range of cement types and properties are described including applications in extremely high temperature or high fluid-loss environments. The discussion includes the use of cement additives such as accelerators, retarders, and density adjusters that are critical in tailoring cementing methods to specific applications.

Equipment use in constructing the injection well is described including centralizers, float shoes, collars, scratchers, plugs, and cement baskets. Displacement fluids and washes used in cementing are also described.

Chapter 5, Downhole, Wellhead and Ancillary Equipment, describes the selection and installation of equipment required to construct and operate injection wells. The

chapter initially addresses bottom-hole configurations or completions including open-hole, screened/liner, and perforated casing options. The various completion types used in conjunction with these options are covered including tubing and packers, tubing with open annulus, and tubingless completions. Well stimulation techniques used in well development are also described including hydraulic fracturing, acidization, and surging.

Equipment used in many injection-well completions is described including tubing, packers, and wellheads. Surface equipment for water handling, monitoring, pumping, and corrosion control is also discussed. This includes a brief discussion of pretreatment, surge protection, and annular inhibition.

Chapter 6, Corrosion and Corrosion Control, provides an overview of the types of corrosion, the means of detection and possible control measures. The types of corrosion considered include oxygen, carbon dioxide, hydrogen sulfide, acid/alkaline, and galvanic corrosion. Detection and measurement methods to assess corrosion behavior include weight loss specimens, electrical resistance probes, electrochemical tests, and well logging.

Corrosion control measures for injection wells can initially involve the selection of corrosion resistant materials such as stainless steel casing and protective coatings. Pre-injection treatment, chemical inhibition, and cathodic protection are also considered in the chapter.

Chapter 7, Formation and Well Evalution and Testing, addresses the techniques used to determine subsurface conditions including well integrity and formation characteristics. Coring and sampling procedures are described including sampling and analysis of drill cuttings and formation coring and fluid sampling. Borehole geophysical techniques that are used to evaluate well construction features are described. These techniques include the numerous electrical, nuclear, and acoustic methods as well as caliper, electromagnetic, temperature, noise, and

radioactive tracer logging techniques. In addition, there are several pressure evaluation procedures, such as drill-stem and injectivity testing, which can be used to assess formation and well characteristics. The principles and applications of these various techniques are discussed in the chapter. These tests help in determining fracture pressures and injection rates for prospective injection intervals.

Chapter 8, Class I Injection Wells, describes the basic practice of industrial and municipal deep-well disposal. Injection-well site evaluation and formation fluid compatibility are specifically addressed. Various examples are provided that indicate key well design parameters and include, steel pickling wastes and nylon manufacturing process wastes.

Chapter 9, Class II Injection Wells, describes the basic practices and well-design characteristics used in hydrocarbon related injection wells including salt water disposal, enhanced recovery, and liquid hydrocarbon storage.

Chapter 10, Class III and Class V Injection Wells, describes the basic practices, and where available, well design characteristics used in a wide variety of energy and mineral production technologies. These technologies include: Frasch sulfur, fresh water solution mining, chemical-solvent solution mining, in-situ combustion of fossil fuels, and geothermal energy production.

Chapters 8, 9 and 10 present discussions of key parameters affecting the contamination potential from both formation failure and well leakage. Key parameters include extreme high temperature environments, subsidence, and corrosive injectants.

Throughout the literature and in the field various terms are used to describe the same condition or equipment, i.e., well bore and borehole. For the sake of clarity, this document attempts to use only one term throughout. It is recognized, however, that the term used herein may be inconsistent with common practice in certain areas or for certain well-construction practices. The regulator, therefore, should attempt to familiarize himself with these "local usages."

2. INJECTION-WELL SITE EVALUATION

The following section describes site-evalution data, its application, and its use as generally applied to underground injection operations. Detailed siting considerations vary widely for the specific classes of injection operations, a result of their individual technical and resource characteristics. (These class-specific siting considerations are discussed in Chapters 8, 9, and 10). The need for collecting and reporting the following data must, therefore, be considered on a case-by-case basis and may not be equally applicable to the various classes of injection activities.

2.1 SITE-EVALUATION DATA

Knowledge of the site-specific and regional aspects of the geologic and hydrologic characteristics is fundamental to the evaluation of the suitability of the site for injection, as well as the suitability of design, construction, operation, and monitoring. In defining the geologic environment, the subsurface rock units are described in terms of their lithology, thickness, areal distribution, structural configuration, engineering properties, and potential resource value. The chemical and physical properties of subsurface fluids and the nature of the local and regional subsurface flow system which comprise the hydrologic environment must also be defined.

2.1.1 Rock Types

Rocks are described in terms of their origin and their lithology, the latter characteristics being defined by their composition and texture. By origin, the three broad rock types are classified as igneous, metamorphic, and sedimentary. While nearly all rock types can, under favorable circumstances, serve as injection zones, sedimentary rocks are most likely to have suitable geologic and engineering characteristics. These characteristics are sufficient porosity, permeability, thickness, and areal extent to permit the rock to act as a liquid-storage reservoir at safe injection pressures.

Unfractured shale, clay, siltstone, anhydrite, gypsum, and salt provide good seals against upward or downward flow of fluids (salt, anhydrite, and gypsum units may also be used as injection intervals during solution mining of these minerals). Limestone and dolomite may also be satisfactory confining beds; but these rocks commonly contain fractures or solution channels, and their adequacy should be determined in each case.

Study of the composition, sequence, thickness, age, and correlation of the rocks in a region is stratigraphic geology or stratigraphy. The basic means of display of data used in stratigraphic studies is the columnar section, which is a graphic representation of the rock units present at a location or in a region. Figure 2.1 is a generalized columnar section for northeastern Illinois. This particular example was selected because it shows a variety of rock types, is typical of the east-central states, and is easily interpreted and discussed.

2.1.2 Structural Geology

Structural geology is concerned with the folding and fracturing of rocks and the geographic distribution of these features. Structural geologic characteristics of a region and, on a smaller scale, of a particular site are significant because of their role in influencing subsurface fluid flow, the engineering properties of rocks, and the localization of mineral deposits and earthquakes. Sedimentary rocks may be folded into synclines (downward or trough-like folds) or anticlines (upwards folds). Synclinal basins of a regional scale (hundreds of miles) are viewed as particularly favorable for injection.

Faults are fractures in the rock sequence along which there has been displacement of the two sides relative to one another. Such fractures may range from inches to miles in length and displacements are of comparable magnitudes. Faults may occur singly or in systems so complex that it is not possible to completely define them.

Faults may act either as barriers to fluid movement or as channels for fluid movement. However, little detail is known about how or why some faults are barriers and

others are flow channels. In theory, no fault in a sedimentary rock sequence will be an absolute barrier, but a fault may be of such low permeability relative to the aquifer it cuts, that it is, for practical purposes, a barrier. Since it will seldom be possible for a geologist to initially state whether a fault is a barrier or a flow path, for purposes of preliminary evaluations it would be appropriate to consider any significant fault to be a flow path. A significant fault might be defined as one that is of sufficient length, displacement, and vertical persistence to provide a means of travel for injection fluids to an undesirable location such as an underground source of drinking water. If, as a consequence of this initial assumption, the fault would be an environmental hazard it may be necessary to either test the fault directly rising field injection techniques or abandon the site for injection.

Within the past decade observations and research have led earth scientists and engineers to the conclusion that, under certain circumstances, subsurface fluid injection can stimulate movement along some faults. When movement occurs, stored seismic energy is released as an earthquake. Although much remains to be learned about this subject, it appears that the circumstances favorable to earthquake generation are relatively rare (Warner and Lehr, 1977).

Fractures also exist along which there has been no movement. This type of fracture may be referred to as a crack or joint to distinquish it from a fault. Cracks and joints are important sources of porosity and permeability in some aquifers, but can be undesirable when they channel fluids rapidly away from an injection well in a single direction or where they provide flow paths through confining strata. The presence and nature of fractures is determined by examination of rock cores obtained during drilling, by well logging and testing methods, and from experience with other wells drilled in the same region.

2.1.3 Engineering Properties of Rocks

To make a quantitative evaluation of the mechanical response of the subsurface environment to injection, the engineering properties of the injection zone including

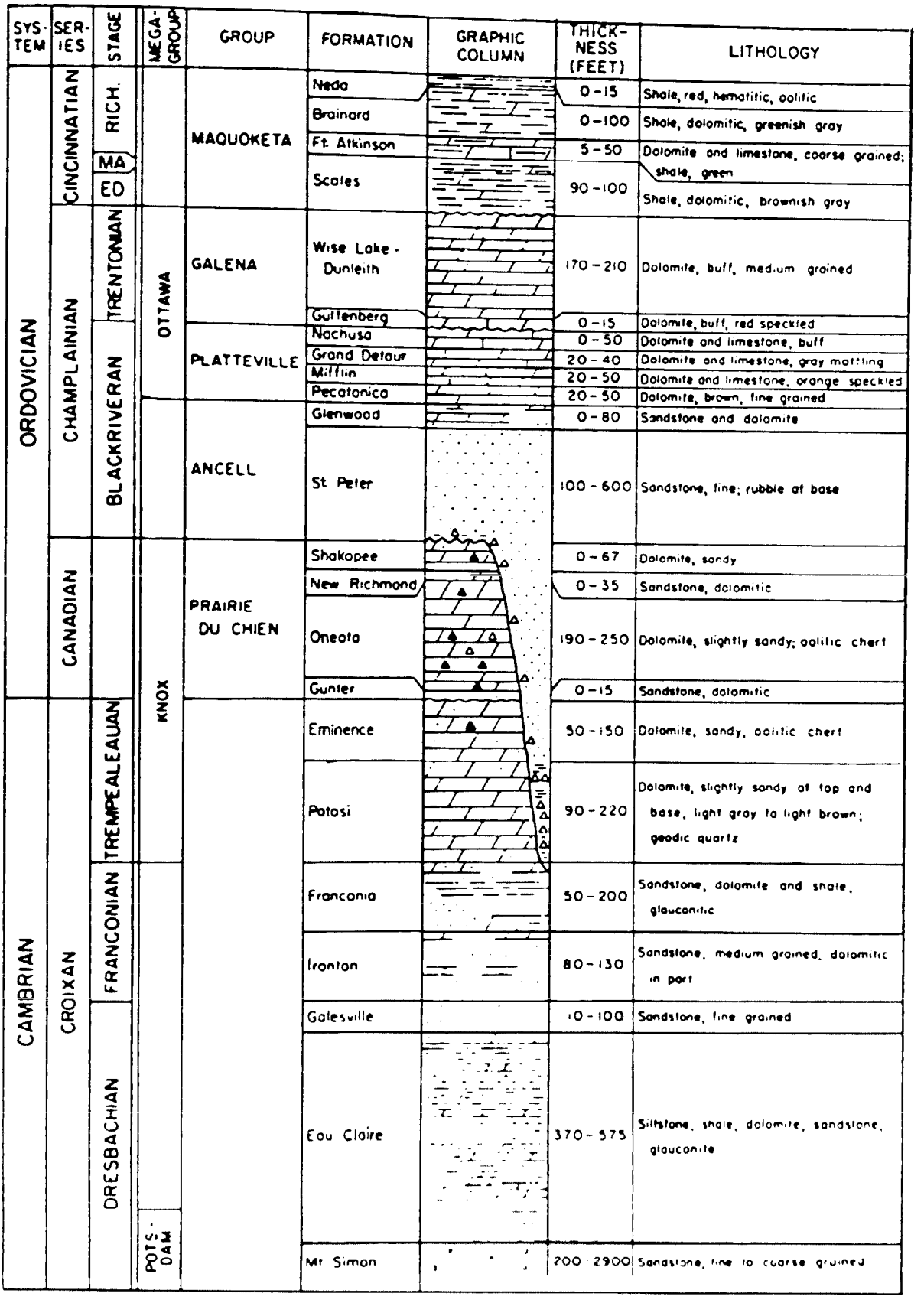

Figure 2.1. Generalized geologic sections of Cambrian and Ordovician strata in northeastern Illinois (Warner and Lehr, 1977)

porosity, permeability, compressibility, temperature, and state of stress must be determined.

Porosity

Porosity is the ratio of the volume of void spaces in a rock to total volume of the rock expressed as a decimal fraction or percentage.

$$\phi = \frac{V_v}{V_t} \qquad \text{[dimensionless]} \qquad (2\text{-}1)$$

where:

ϕ = Porosity
V_v = Volume of Rock
V_t = Total volume of Rock Sample

Porosity may be expressed as either total porosity or effective porosity. Total porosity is a measure of all void space; effective porosity is a measure of the volume of interconnected voids. Effective porosity is more closely related to the hydraulic properties of a rock unit since only interconnected pore spaces are available to fluids flowing through the rock.

Additionally, porosity may be either primary or secondary. Primary porosity includes original intergranular or intercrystalline pores and is also associated with fossils and bedding planes. Secondary porosity results from fractures, solution channels, and recrystallization and dolomitization. Intergranular porosity occurs principally in unconsolidated sands and in sandstones, and depends on the size distribution, shape, angularity, packing arrangement, mineral composition, and degree of natural cementation of the grains.

Porosity can be measured in the laboratory on consolidated rock cores taken during drilling. Core analysis of unconsolidated material is difficult, but techniques have

recently been developed to obtain cores from such formations and to perform laboratory analyses upon them with some assurance that the results are representative of the in-situ formation properties (Mattax and Clothier, 1974).

Porosity contributed by fractures and solution channels is also difficult to measure in the laboratory. A major deficiency of core analysis is that samples being measured comprise only a small fraction of the interval of interest and may not be representative of the rock in place. To determine the porosity of strata in place, various borehole geophysical methods can be used (see Chapter 7).

The porosity of sedimentary rocks range from over 35 percent in newly deposited sand to less than 5 percent in lithified sandstone. Dense limestone and dolomite may have almost no porosity. Porosity is not a direct measure of the overall reservoir quality of a rock unit, but a reservoir with high porosity is generally better than one with low porosity.

Permeability

The permeability of a rock is the measure of its capacity to transmit a fluid under an applied potential gradient. The term hydraulic conductivity is frequently used interchangeably with the term permeability, but they are not truly interchangeable. (Hydraulic conductivity is a measure of the quantity of water at a specified temperature that will flow through a unit cross-sectional area of a porous material per unit of time under a unit hydraulic gradient.)

$$P = \frac{Q_m I}{A_d} \quad [V/L^2] \qquad (2\text{-}2)$$

where:

P = Coefficient of Permeability
Q_m = Flow Rate
I = Hydraulic Gradient
A_d = Cross-Sectional Area

As with porosity, intergranular permeability is influenced by the grain properties of rocks (sand, sandstone, siltstone, shale, etc.). Whereas porosity is not theoretically dependent on grain size, permeability is strongly dependent on this property. The smaller the grains, the larger will be the surface area exposed to the flowing fluid. Since it is the frictional resistance of the surface area that lowers the flow rate (i.e. the smaller the grain size, the lower the permeability), shales are generally good confining intervals. As with effective porosity, permeability also results from interconnected solution channels and fractures as well as from interconnected intergranular spaces.

Permeability values from core samples of units used for injection range from over one hundred gallons per day per square foot (gpd/ft^2) (greater than 1 x 10^{-3} cm/sec) to less than 0.1 gpd/ft^2 (less than 1 x 10^{-6} cm/sec); but, an average value of less than 1 gpd/ft (1 x 10^{-5} cm/sec) for an overall interval would be considered to be very low, and a value of 0.5 to 5 gpd/ft^2 (1 x 10^{-4} to 1 x 10^{-3} cm/sec) would be good to very good. Shales, which are considered to be suitable confining strata, have permeabilities on the order of 10^{-5} gpd/ft^2 (less than 1 x 10^{-9} cm/sec), or thousands of times less than an adequate injection interval. As with porosity, permeability can be measured on core samples in the laboratory or by tests performed in the borehole (see Chapter 7).

In evaluating the suitability of an injection or confining unit, injection-zone thickness is as important as permeability. Saturated injection-zone thickness multiplied by permeability is the transmissivity of the rock unit, the rate at which fluid at the existing fluid viscosity and density is transmitted through a unit width of aquifer at a unit hydraulic gradient. The unit of transmissivity (T) is gallons per day/foot, square feet/day or square meter/second.

The permeability of an injection zone to two or more fluids of differing capillary properties is not the same as the permeability to a single fluid. When two fluids, for example water and oil, are flowing simultaneously through a rock, the permeability to either is lower than it would be if the rock were fully saturated with one of the fluids.

Compressibility

The compressibility of an elastic medium is defined as:

$$\beta = \frac{-\partial V}{V \partial P} \qquad [F/L^2]^{-1} \qquad (2\text{-}3)$$

where:

β = Compressibility of Medium
V = Volume
P = Pressure

The compressibility of an aquifer includes the compressibility of the rock material and of the contained fluids. To account for the compressibility of both, engineers often arbitrarily use a compressibility which ranges from 5×10^{-6} to 1×10^{-5} psi^{-1} [3.4×10^{-2} to 6.9×10^{-2} $(N/m^2)^{-1}$] compared with the compressibility of water alone which is about 3×10^{-6} psi^{-1} [2.1×10^{-2} $(N/m^2)^{-1}$) (Amyx, et al. 1960). Van Everdingen (1968) uses this procedure in arbitrarily selecting a fluid and rock compressibility of 6×10^{-6} psi^{-1} [4.1×10^{-2} $(N/m^2)^{-1}$] for the example calculations that he presents.

A parameter related to compressibility is the storage coefficient (S) which is defined by Lohman (1972). The storage coefficient is the volume of water an aquifer releases or takes into storage per unit surface area per unit change in hydraulic head. Storage-coefficient values are dimensionless and normally range from 5×10^{-5} to 5×10^{-3} for confined aquifers. The storage coefficient may be estimated, or it may be determined from aquifer tests.

Temperature

The temperature of the aquifer and its contained fluids is important because of the effects that temperature has on fluid properties. The temperature of shallow ground

water is generally about 2°F to 3°F (1.2°C to 1.8°C) greater than the mean annual air temperature. Below the shallow ground-water interval, the temperature increases at an average rate of about 1.5°F per 100 feet of depth (3°C per 100 meters) but the rate of increase is variable and may range from as much as 5°F (9.8°C) to less than 1°F (2.0°C) per 100 feet of depth (9.8°C to less than 2.0°C per 100 m) (Levorsen, 1967). This temperature increase with depth is termed the geothermal gradient. The geothermal gradient is determined from temperature measurements made in deep wells and is calculated by dividing the difference between the temperature at a point in the subsurface and the mean annual surface temperature by the depth to the observation point. Geothermal gradient maps for the United States have been prepared by the American Association of Petroleum Geologists, Tulsa, Oklahoma, and can be obtained from that organization.

State of Stress

In a sedimentary-rock sequence, the total normal vertical stress increases with depth of burial under increasing thickness of overburden. It is commonly assumed that the normal vertical stress increases at an average of about 1 psi per foot of depth (2.26 N/m^2 per meter). The lateral stresses may be greater or lesser than the vertical stresses, depending on geologic conditions (Warner and Lehr, 1977). In areas where crustal rocks are actively compressed, lateral stresses may exceed vertical ones. In areas where crustal rocks are not in active compression, lateral stresses may be less than the vertical stresses. Prior to drilling a well, lateral stress may be estimated from hydraulic-fracturing data of nearby wells and/or knowledge of the tectonic state of the region in which the well is located. Only now is the tectonic state of various regions being determined. For example, Kehle (1964) concluded, as a result of hydraulic fracturing data from four wells, that the stresses at well locations in Oklahoma and Texas were representative of an area that was tectonically in a relaxed state. Sbar and Sykes (1973) characterized much of the eastern and north-central United States as being in a state of active tectonic compression.

To predict the pressure at which hydraulic fracturing or fault movement would be expected to occur, it is necessary to estimate the state of stress at the depth of the

injection zone. On the other hand, determination of the actual fracturing pressure allows computation of the state of stress (Kehle, 1964).

The general equation for total normal stress across an arbitrary plane in a porous medium is (Hubbert and Willis, 1972):

$$S = p + \sigma \qquad [F/L^2] \qquad (2\text{-}4)$$

where:

S = Total Stress
p = Fluid Pressure
σ = Effective or Intergranular Normal Stress

Effective stress, as defined by Equation 2-4, is the stress available to resist hydraulic fracturing or the stress across a fault plane that acts to prevent movement on that fault. The equation shows that if total stress remains constant, an increase in fluid pressure reduces the effective stress and a decrease in fluid pressure increases effective stress. When the effective stress is reduced to zero by fluid injection, hydraulic fracturing occurs. In the presence of a fault along which shear stress already exists, fault movement will occur before normal stresses across the fault plane are reduced to zero.

2.1.4 Properties of Subsurface Fluids

To evaluate the chemistry of aquifer water and the compatability of the injection fluid, it is necessary to obtain samples after a well is drilled; samples from previously drilled wells may provide a good indication of what will be found. Geophysical logs are also useful for estimating the dissolved-solids content of aquifer water in intervals that are not sampled (see Chapter 7). The range of dissolved ions present in ground water is so great that a complete chemical analysis is seldom performed. In most instances, an analysis will be made for the principal ions and others on a selected basis. Other fluid properties that may be important in site evaluations are viscosity, density, pressure, and compressibility.

Chemistry

Chemical analyses of ground water are useful for correlation of stratigraphic units, interpretation of subsurface-flow systems, and calibration of borehole logs. The chemistry of contained water is important because of the possibility of reaction with injection fluid and effects on the integrity of well components.

Table 2.1 lists the chemical and physical determinations that may be made for the naturally occurring water in an injection zone. The routine determinations characterize the general geochemical nature of the water. The additional analyses suggested for an injection zone are for the purpose of predicting the reactivity of that water with the injection fluid, and would be selected on the basis of reactions that are suggested by the chemistry of the two fluids. Samples of water taken from shallow fresh-water aquifers should be analyzed more completely for minor elements so that their baseline quality is well established and the presence of any introduced contaminants can be detected.

Viscosity

Viscosity is the property of a fluid to resist flow, and is important in determining the rate of flow of a fluid through a porous medium. The common unit of viscosity is the poise, centipoise or Newton-second per square meter. Both temperature and dissolved solids content can have a significant effect on viscosity. In most cases, the effects will tend to be offsetting, since temperature and dissolved solids content both commonly increase with increasing depth.

Density

The density of a fluid is a measure of its mass per unit volume. While liquid density increases with increasing pressure and decreases with increasing temperature, the changes are very small within the range of pressures and temperatures of interest to injection-well operators. For example, the density of water decreases only 0.04 gm/cm^3 when temperature increases from 60°F to 210°F (15.5°C to 98.8°C), and increases only about 0.04 gm/cm^3 from 0 to

TABLE 2.1
COMMON WATER ANALYSES PERFORMED ON
SUBSURFACE WATER SAMPLES
(Warner and Lehr, 1977)

Determination	Routine Analysis	Injection-Interval Water Analysis
Alkalinity	X	X
Aluminum		X
Barium		X
Calcium	X	X
Chloride	X	X
Dissolved Oxygen		X
Hydrogen ion (pH)	X	X
Iron	X	X
Magnesium	X	X
Manganese		X
Potassium	X	X
Sodium	X	X
Specific Conductance	X	X
Specific gravity	X	X
Sulfate	X	X
Total Dissolved Solids	X	X

14,000 psi (0 to 9.65 x 10^7 N/m^2). A more important influence on water density is the total dissolved solids content. Figure 2.2 shows the effect of various amounts of sodium chloride on density as expressed as specific gravity at 60°F (15.5°C). Since natural brines may differ significantly from sodium-chloride solutions, it may be desirable to develop empirical relationships between density and dissolved solids.

Pressure

A knowledge of fluid pressure in the zone proposed for injection is important. Fluid pressure can be measured directly in the borehole at the depth of the injection zone by performing a drill-stem test (see Chapter 7). Fluid pressure at the injection zone can also be measured indirectly by determining the static water level in the borehole and computing the pressure of the fluid column at the depth of interest.

Figure 2.3 shows how fluid pressure increases with depth in a borehole filled with fresh water having a specific gravity of 1.0. When the average specific gravity of the water is other than 1.0, the rate of pressure increase varies accordingly. For example, a borehole filled with water having a dissolved-solids content of 65,000 mg/l has a specific gravity of 1.035. Fluid pressure, therefore, increases at a rate of 0.45 psi/ft (1.035 x 0.433 psi/ft) (1.02 x 10^4 N/m^2 per meter), and would be 450 psi (3.1 x 10^6 N/m^2) at the bottom of a 1,000-ft-deep (304.8 m) water-filled hole.

Anomalous formation pressures may be encountered at sites selected for injection; the existence of unusually high or low pressures and the possible reasons for their existence should be recognized. Hanshaw and Zenn (1965) list ten possible causes of anomalous pressure: (1) high hydraulic head, (2) rapid loading and compaction of sediments, (3) tectonic forces, (4) temperature effects, (5) osmotic-membrane phenomena, (6) "fossil" pressure corresponding to previous greater depth of burial, (7) infiltration of gas, (8) mineral-phase changes involving water, (9) solution or precipitation of minerals, and (10) water from magmatic intrusions. Of these mechanisms, the first five most commonly occur. Large scale injection or extraction of fluids can also cause anomalous pressure conditions.

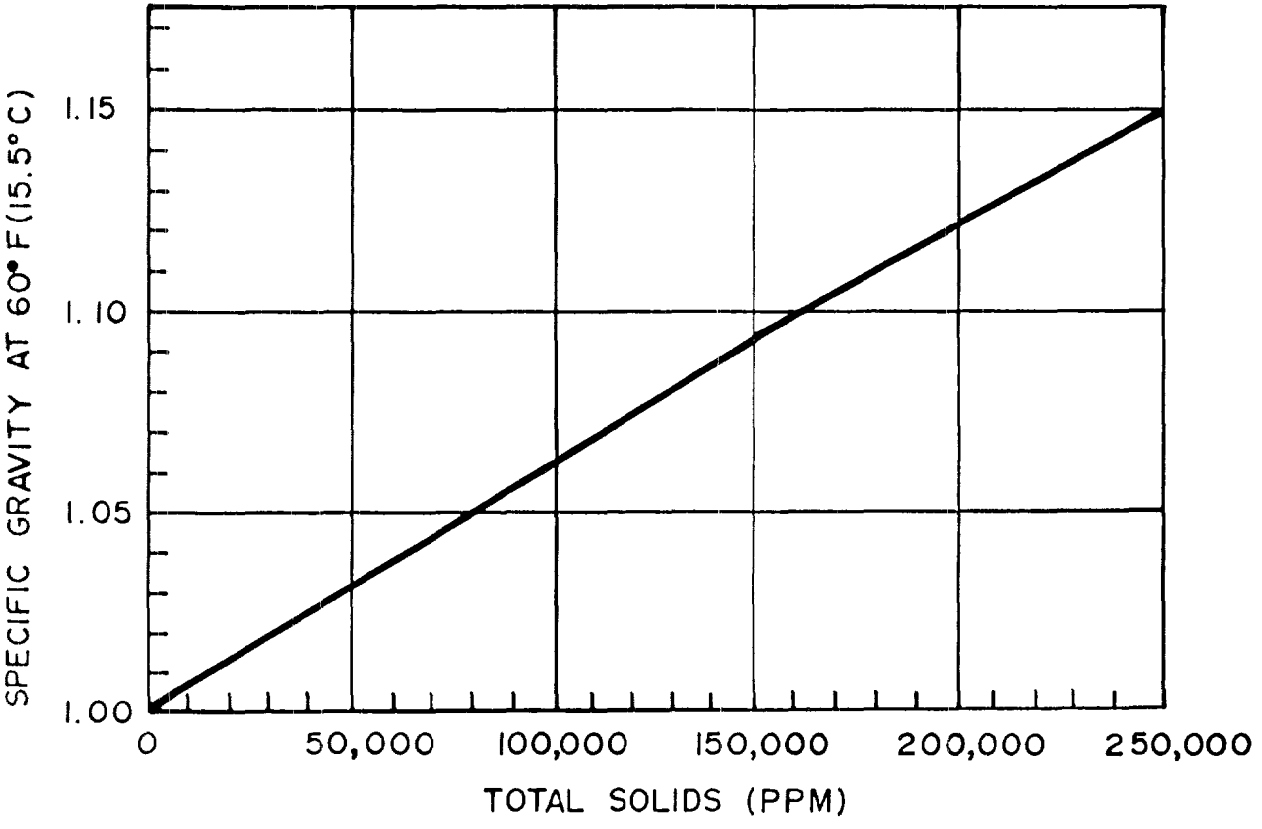

Figure 2.2. Specific gravity of sodium-chloride solutions containing different levels of total dissolved solids

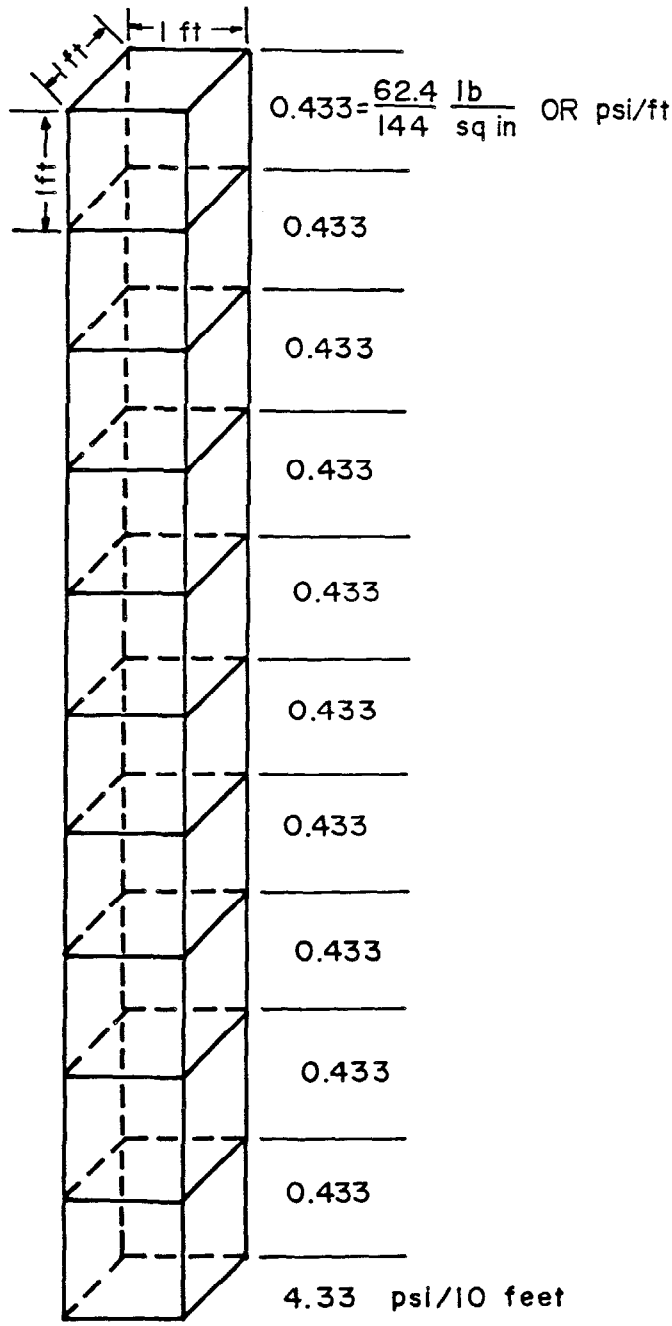

Figure 2.3. Hydraulic pressure gradient in a column of water (Warner and Lehr, 1977)

Compressibility

All pore space in strata used for injection is already fluid-filled. Injection fluid is emplaced by displacing and compressing ground water and by compressing the rock material of the aquifer. The compressibility of water varies both with temperature and pressure; however, water compressibility will generally be within the range of 2.8×10^{-6} to 3.3×10^{-6} psi^{-1}, [1.9×10^{-2} to 2.28×10^{-2} $(N/m^2)^{-1}$].

2.1.5 Subsurface Resources

It is the goal of both regulatory agencies and well operators to prevent jeopardizing underground sources of drinking water, oil or gas, coal, and other subsurface resources. Therefore, the occurrence and distribution of all significant subsurface resources may be determined. This determination is made from reference to published reports and by consultation with public officials, companies, and individuals familiar with subsurface resources of the area. Also, the actual drilling will show the location and nature of resources present at the well site.

2.2 ACQUISITION AND USE OF GEOLOGIC AND HYDROLOGIC DATA FOR WELL-SITE EVALUATION

To predict the performance of injection wells and their effects on the environment, the type of evaluation data described above must be estimated prior to well construction, and the actual geologic characteristics and values for rock and fluid properties determined during well construction and testing. After the geologic and engineering data are obtained, they may be evaluated qualitatively by professionals or they may be used in calculations to predict the probable performance of a well constructed at the site.

2.2.1 Data Obtainable from Existing Sources Prior to Drilling

Prior to drilling, the geologic and engineering data needed for site evaluation are obtained, where available, from Federal and State geological surveys, State oil and gas agencies, State water resources agencies, and some universities. In addition, private companies in the petroleum industry acquire and sell well logs, other subsurface data, and services. In some cases it may be feasible to go to individual oil companies or consultants for subsurface data that are not publicly available.

2.2.2 Surface Geophysical Surveys

It is possible to obtain considerable original subsurface geological information without drilling by the use of surface geophysical methods, including seismic, electrical, magnetic, and gravity surveys. However, it can be anticipated that surface geophysical surveys will not be widely used for injection-well site studies because of the nature of the data obtained and its costs.

2.2.3 Data Obtainable During Well Construction and Testing

A wealth of subsurface geologic and engineering information can be obtained during the drilling and the testing of any well. The extent to which information should be obtained depends on the availability of existing data in the immediate vicinity of the well. Where extensive data are available, such as in a developed oil field, a minimal amount of new information will usually be acquired. At a site where no wells have previously been drilled within miles, it may be necessary to collect all the important information during installation of a test boring or well.

Methods of data collection during drilling of the test well are presented in Table 2.2. Such data can be used to make quantitative calculations concerning injection-zone performance.

TABLE 2.2
METHODS OF OBTAINING DATA ON
THE CHARACTERISTICS OF INJECTION WELLS

A. Coring and collection of cuttings

B. Formation fluid sampling

C. Well logging including:

1. Sample (cuttings and core) logs.

2. Driller's logs.

3. Drilling time logs.

4. Mud logs.

5. Geophysical logs:

a. electrical logs;

b. elastic wave logs;

c. radiation logs;

d. other.

6. Miscellaneous logs:

a. caliper logs;

b. dipmeter logs;

c. deviation logs;

d. production-injection logs.

D. Drill-stem testing.

E. Injectivity or pump testing.

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3. DRILLING AND CASING METHODS

Chapter 3 outlines a general description of drilling techniques, their selection, and their capabilities. The installation of casing and methods of cementing it in the borehole are provided. Special conditions encountered in these operations are also discussed.

3.1 DRILLING TECHNOLOGY

Various methods are used to drill injection wells. The choice of drilling method depends upon the purpose of the well, the geology of the well site, the character of the formations to be drilled, the depth of the injection zone, the availability of drilling equipment, and other site-specific factors. Injection wells are generally drilled in a manner similar to oil, gas, or water wells.

The three major methods used for drilling are the cable-tool method, the rotary method, and the reverse-rotary method. The other less widely used methods will be discussed briefly.

3.1.1 Cable-Tool Drilling

Cable-tool drilling was the method used to drill the first oil wells in the United States (Campbell and Lehr, 1973). Drilling is performed by lifting and dropping a heavy string of tools suspended at the end of a cable. The tools consist of a bit, drill stem, drilling jars, and rope socket (Figure 3.1). As the string strikes consolidated rock, the bit chips the rock into fragments; in unconsolidated sediment, the bit loosens the material. Water is added to the borehole in dry formations to cool the bit and to form a slurry of cuttings which is removed by a sand pump or bailer (Figure 3.2). A check valve retains the slurry in the bailer for removal.

Cable-tool drilling in unconsolidated sediment differs from drilling in consolidated rock. A casing is usually driven into the unconsolidated sediment, the bit is used to loosen the sediment plug inside the casing, water is

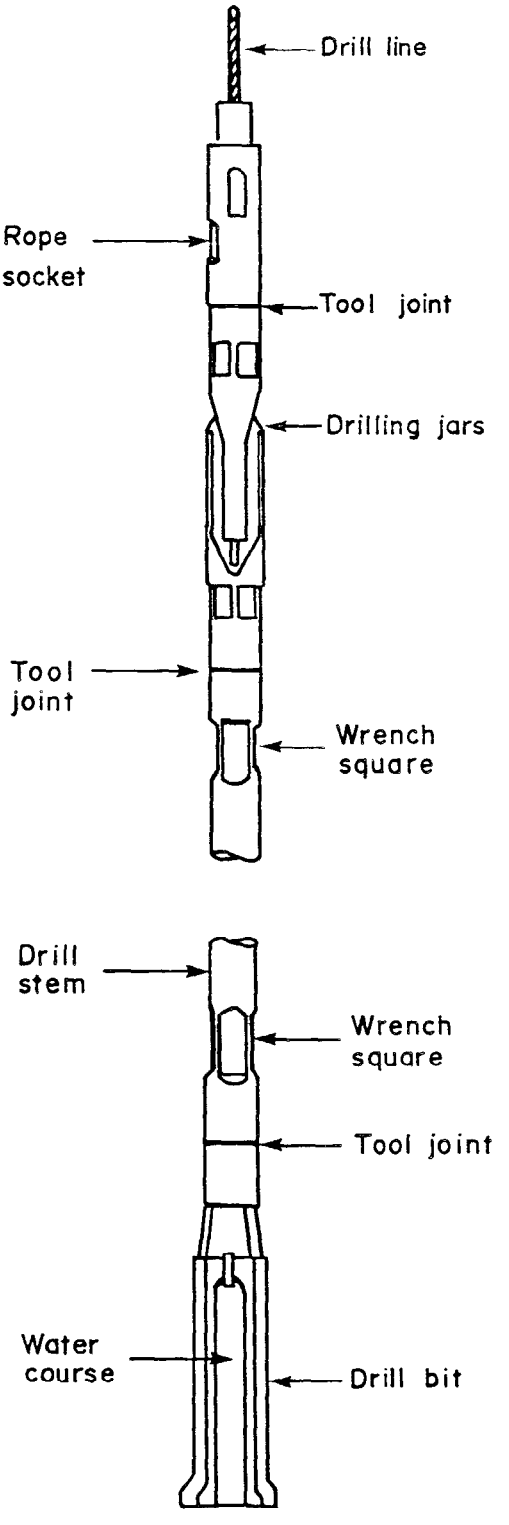

Figure 3.1. Components of the string of tools for cable-tool drilling (Johnson Division, UOP, Inc., 1975)

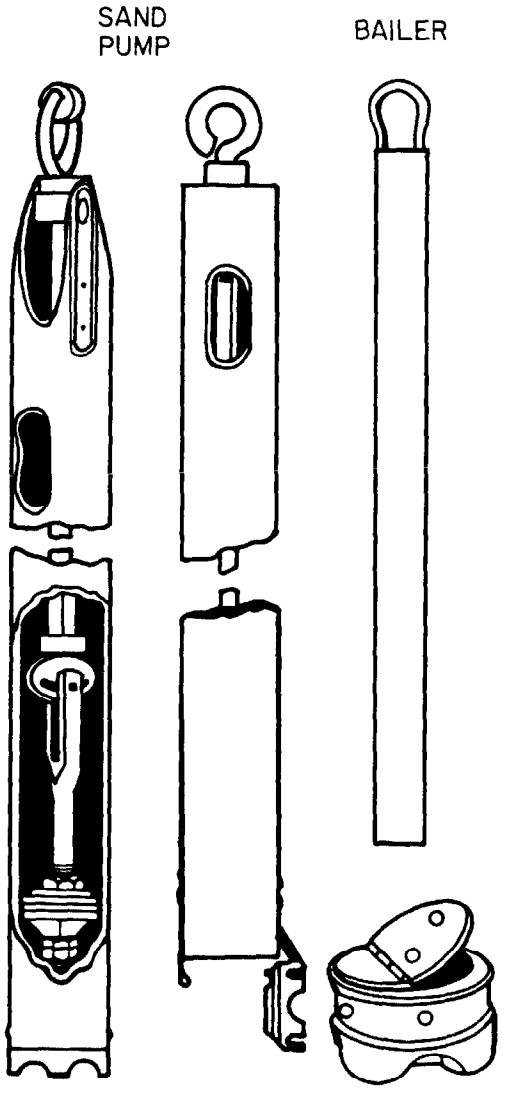

Figure 3.2. Sand pump and bailer used in cable-tool drilling (Johnson Division, UOP, Inc., 1975)

added to the pipe, and the slurry is bailed out. The driving, drilling, and bailing are continued until the casing reaches the final depth. The driven casing cannot always be pushed to the total depth of the well in one length. Casing lengths are limited primarily by friction on the outside and by potential buckling of the pipe. Consequently, it is common to telescope smaller diameter casings in the well for continued drilling to the total depth.

Cable-tool drilling rates are affected by the resistance of the rock, the weight of the drill tools, the diameter of the bit, the length of the stroke, the number of strokes per minute, and the thickness and depth of accumulated cuttings in the borehole (Johnson Division, UOP, Inc., 1975). With increased depth, more time is required to remove drilling tools, bail out the slurry, and reinsert the tools. Longer cable lengths require reduced tool weights and shorter strokes. Although a record depth of 11,145 feet (3,397 m) has been documented (Campbell and Lehr, 1973), such labored drilling has limited well depth to less than a few thousand feet. The cable-tool method is seldom used for construction of injection wells because other drilling methods permit faster completion times, and permit cementing programs to protect underground sources of drinking water. Many old oil and gas wells, constructed by the cable-tool method, may subsequently be converted to injection wells.

The cable-tool method is advantageous when accurate formation samples are necessary. The formation cuttings are not as contaminated with drilling fluid (mud) nor are they as finely crushed as in rotary drilling. Exact depths of formation changes are easier to identify. Other advantages include a low operating cost, low demand for water, and rigs that are well suited to rugged terrain (Campbell and Lehr, 1973; Johnson Division, UOP, Inc., 1975).

3.1.2 Rotary Drilling

The rotary drilling method is the technique most widely used for injection-well drilling (Warner and Lehr, 1977). Rotary drilling became popular in the early 1900s because the method is faster than cable-tool drilling and deeper

holes of larger diameter can be drilled. The rotary-drilling method is used for water-well and injection-well drilling, but the wealth of research and data available comes from the oil and gas industry.

Rotary drilling consists of a rapidly rotating bit which cuts the borehole while drilling fluid is circulated down the drill pipe to remove the cuttings from the hole. The drilling fluid is forced out through the bit to cool and lubricate it. The fluid, carrying cuttings, flows upward to the surface through the annulus formed between the outside of the drill pipe and the borehole. The drilling fluid flows through a ditch or shale shaker where samples may be collected. It then flows into a pit where cuttings settle out and it is finally pumped back down the hole (Campbell and Lehr, 1973; Johnson Division, UOP, Inc., 1975; Warner and Lehr, 1977).

The components of a rotary-drill operation are illustrated in Figure 3.3. At the base of the borehole is a drill bit which is attached to the lower end of a strong-walled pipe called a drill string. The drill string consists of one or more drill collars and several rods. The drill collars concentrate weight near the bit to keep the hole as straight as possible. The drill rods are then attached to the kelly at the top.

The kelly passes through the opening in the rotary table on the drill rig. The kelly is designed to engage the drive bushings in the rotary table and force the entire drill string to turn with the rotary table. As the rotary table and drill string rotate, the kelly slips through the drive bushings feeding the bit downward, thus drilling the hole. The upper end of the kelly connects to a water swivel and the entire string hangs from the swivel suspended from a traveling block in the derrick (Johnson Division, UOP, Inc., 1975).

Various drilling fluids are used in rotary drilling including water, water mixed with clay, oil-based fluids, air, gas, or foam. The drilling fluids most commonly used are emulsion muds which are a suspension of solids and droplets of liquids in a second liquid, or drilling muds which are a suspension of solids in a liquid. A common drilling mud is composed of bentonite clay and water (Campbell and Lehr, 1973; Petroleum Extension Service, 1975).

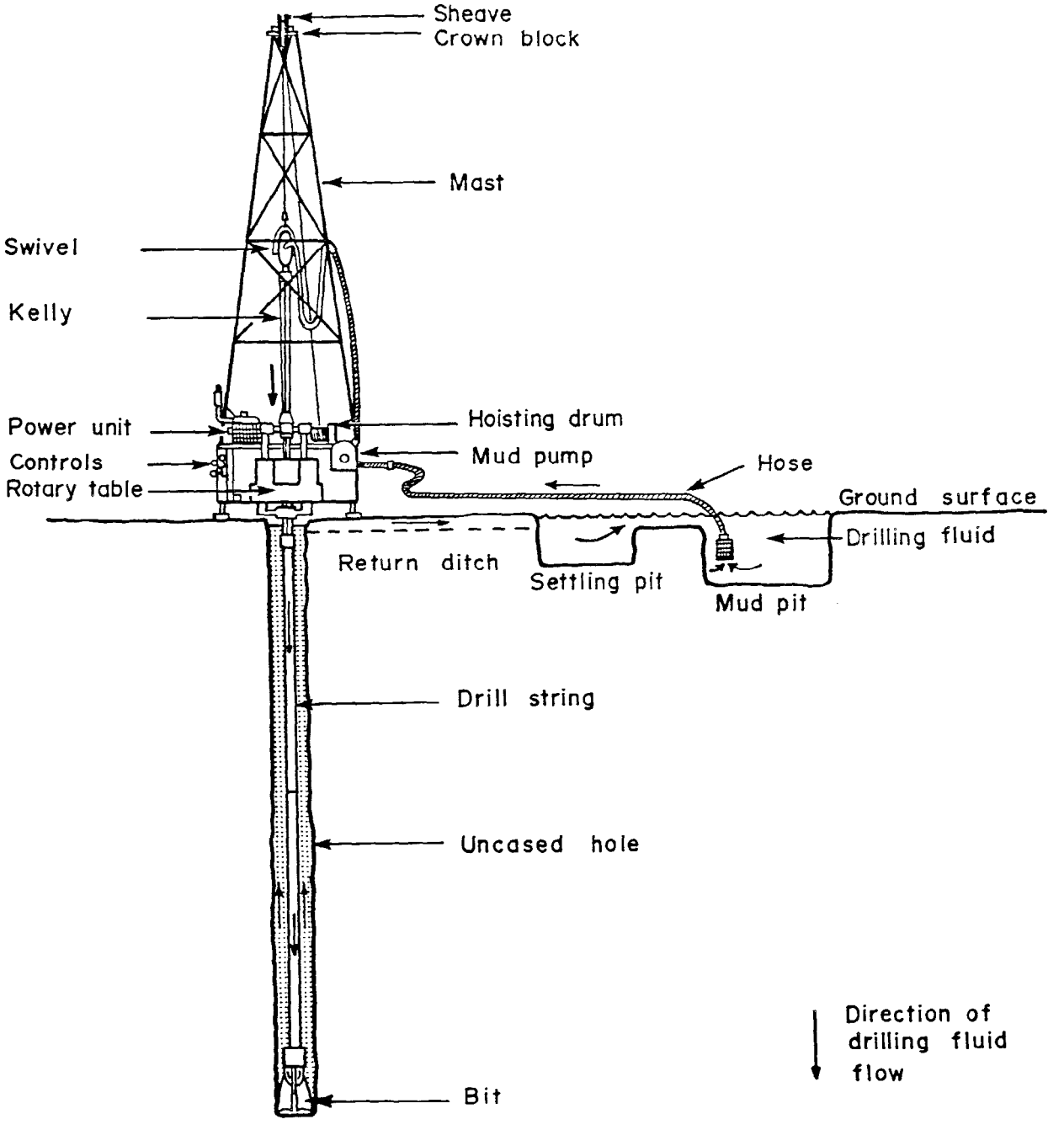

Figure 3.3. Components of the rotary drilling operation

The drilling fluid is used to clean the borehole and keep it free of cuttings. The ability of a drilling fluid to transport cuttings out of the hole is dependent upon the rate of circulation of the fluid and the characteristics of the fluid itself. Some drilling fluids keep cuttings in suspension when circulation stops during bit changes and drill-rod connections, whereas others (air, gas, and water-based drilling fluids) allow cuttings to settle. The borehole should be properly cleaned before circulation is stopped to prevent settling of cuttings. Cuttings carried to the surface in the drilling fluid are collected for analysis to allow geologic interpretation.

Hydrostatic pressure exerted by the column of drilling fluid helps prevent the borehole wall from caving and prevents inflow of formation water, oil, or gas. Minimum drilling-fluid weights are desirable to allow maximum drilling rates and to lessen lost-circulation problems. With increased formation pressures, however, the weight of the drilling fluid must be increased.

A build-up of drilling fluid on the borehole wall produces a wall cake (filter cake or mud cake). This layer of wall cake helps to prevent the borehole wall from caving. Wall cake also prevents drilling-fluid loss (lost circulation) to the formation during drilling. Special drilling fluid additives such as polymers, sawdust, and lime are used to produce wall cake that is highly effective in preventing lost circulation. It is important to control the build-up of wall cake to prevent sticking of drilling tools or other equipment in the hole.

The decision to use a particular type of drilling fluid is dependent on expected downhole temperature and pressure, total borehole depth, geologic formations, total diameter of casing, thickness of cement seals, constraints of time and money, and availability of drilling rigs and associated equipment. A summary of drilling fluid information is presented in Table 3.1.

The bit and drilling fluid are interdependent factors of the rotary-drilling operation. The two basic types of bits used for drilling are the roller-type for rock formations, and the drag-type for unconsolidated formations. The roller bit exerts a crushing and chipping action on consolidated rock. Drag bits shear and scrape unconsolidated and

TABLE 3.1
DRILLING-FLUID CHARACTERISTICS

Type of Drilling Fluid	Primary Benefit or Limitation
I. WATER-BASED MUDS	
1) Fresh-water muds (none or few chemical additives)	This is a common type of fluid used for drilling the surface hole and generally uses formation clays for the mud. Large volumes of relatively soft fresh water are needed. These muds are inexpensive but are usually used only for shallow formations.
2) Chemically-treated muds	These fluids are used as deflocculants, generally in areas of soft water and natural clays. Chemically treated muds are beneficial for reducing viscosity, gel strength and filtration rate but they cannot withstand temperatures above 93°C (200°F). These muds are not effective when contaminated by calcium or salt.
3) Salt-water muds	Salt-water muds minimize excessive hole enlargement during drilling of a salt formation. Seawater muds are generally used for offshore drilling operations. Limitations of these muds include high costs, potential corrosion problems, bentonite yield is reduced, and formation evaluation methods are less effective (especially specific potential logs).

TABLE 3.1 (Cont'd)

Type of Drilling Fluid	Primary Benefit or Limitation
4) Oil-emulsion muds (oil-in-water muds)	Oil-emulsion muds lessen sloughing of shale formations, limit hole enlargement, increase bit life, and increase drilling rates. Oil-emulsion muds are more expensive than other water-based muds.
II. OIL-BASED MUDS	
Invert emulsion muds (water-in-oil) and oil based muds	These muds allow for more rapid drilling rates than water-based muds. There is no swelling or shrinkage of clays, pipe sticking is reduced, and shale problems lessened. Oil-based muds are more temperature stable than water-based muds and are beneficial in salt formations by limiting hole enlargement. Mud costs are high and there is a potential for water-contamination problems.
III. AIR-GAS FLUIDS	
1) Air or natural gas	Air or natural gas provides maximum penetration rates with low costs. There is no formation damage and no wallcake buildup. The method is advantageous in areas of cavernous limestone or highly fractured rock which would cause lost circulation in conventional rotary drilling.

TABLE 3.1 (Cont'd)

Type of Drilling Fluid	Primary Benefit or Limitation
2) Mist	Mist is used when there is too much natural formation fluid to drill with air. This method requires 30 to 35 percent more air pressure than in dry air drilling with the potential result of sloughing.
3) Foam	Foam lifts cuttings from hole and provides good hole cleaning capabilities in addition to reducing hole sloughing. Bit life is generally improved over dry air drilling.
4) Aerated mud	Aerated muds are used when it is impossible to drill with air, lost circulation is minimized but corrosion may be severe. This method requires the use of good quality, low gel strength mud with sufficient surface casing to limit destruction of upper hole.

soft formations. A jet of drilling fluid is run through the drill bit to cool it, to clean it, and to flush cuttings from the borehole. Figure 3.4 illustrates the various types of bits used in rotary drilling.

Rotary drilling is generally considered the fastest, most convenient, and least expensive drilling method, especially in unconsolidated formations (Freeze and Cherry, 1979). This technique provides the opportunity to drill wells of various diameters and greater depths than with cable-tool drilling.

Several disadvantages inherent in the rotary-drilling operation involve the mixing of formation cuttings from different depths which can cause inaccurate descriptions of formations, clogging of permeable formations by wall-cake build-up in the borehole, and contamination of cement. Other problems can arise because certain types of drilling fluids and additives interfere with geophysical logging (Campbell and Lehr, 1973).

3.1.3 Reverse-Circulation Rotary Drilling

Reverse-circulation rotary drilling is accomplished by utilizing gravity to run the drilling fluid down the annulus around the drill pipe. The drilling fluid picks up the cuttings at the bottom of the hole and is pumped up through holes in the drill bit. The fluid and cuttings move upward inside the drill-string assembly and are pumped to a settling pit, then finally back to the borehole annulus (Johnson Division, UOP, Inc., 1975). Figure 3.5 presents a schematic drawing of reverse-circulation operations. This drilling method is not commonly used for injection wells except in areas of high water production or high hydrostatic head.

Drilling fluid, made with bentonite or other additives, is rarely used in reverse-circulation drilling. The drilling fluid used is more the consistency of muddy water than of mud. Since water is lost to all permeable formations, a considerable amount of make-up water may be necessary in this type of operation and it must be available at the site. Such high water losses commonly occur above the water table (Campbell and Lehr, 1973).

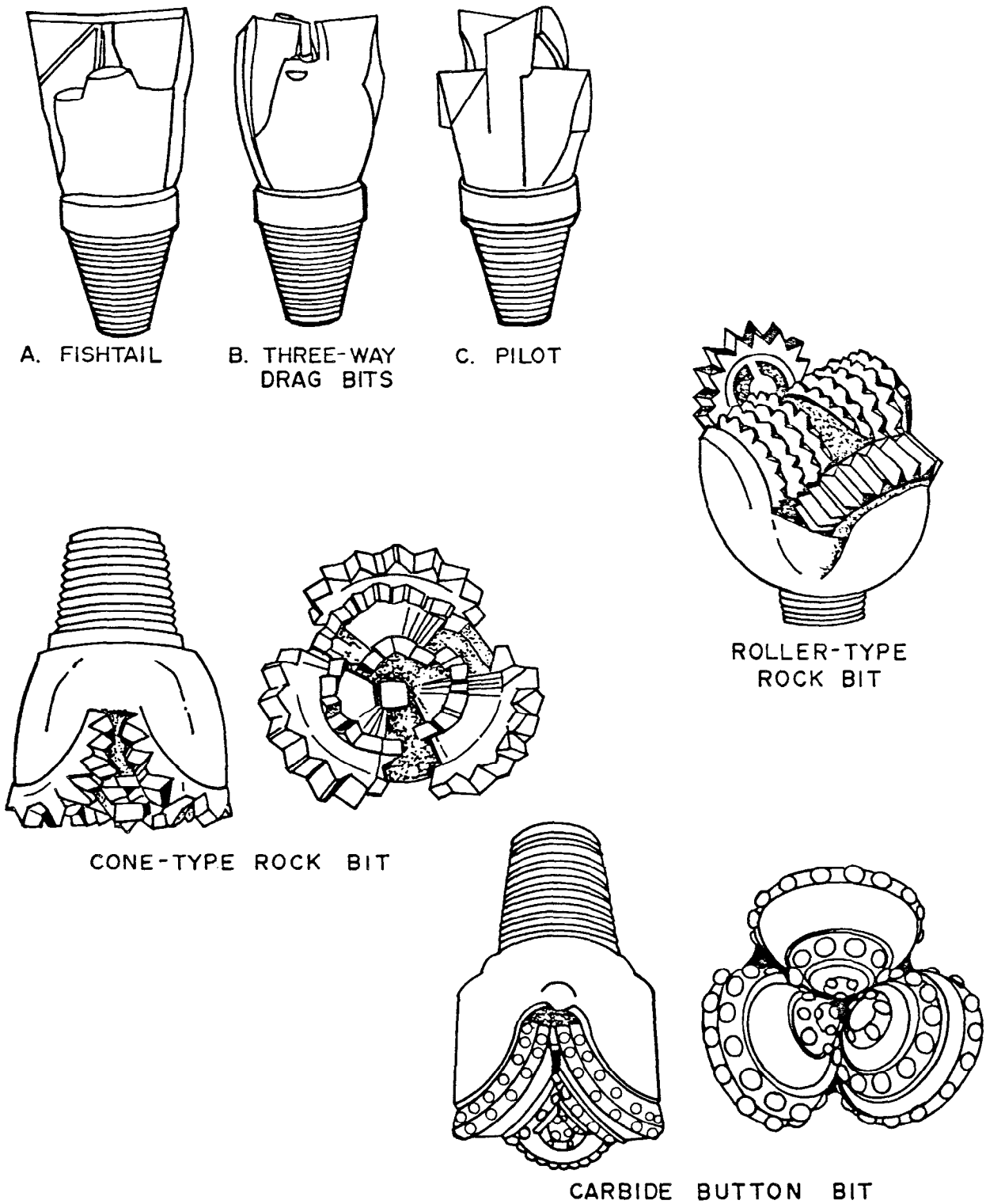

Figure 3.4. Drill bits used in rotary drilling (Speedstar Division, n.d.)

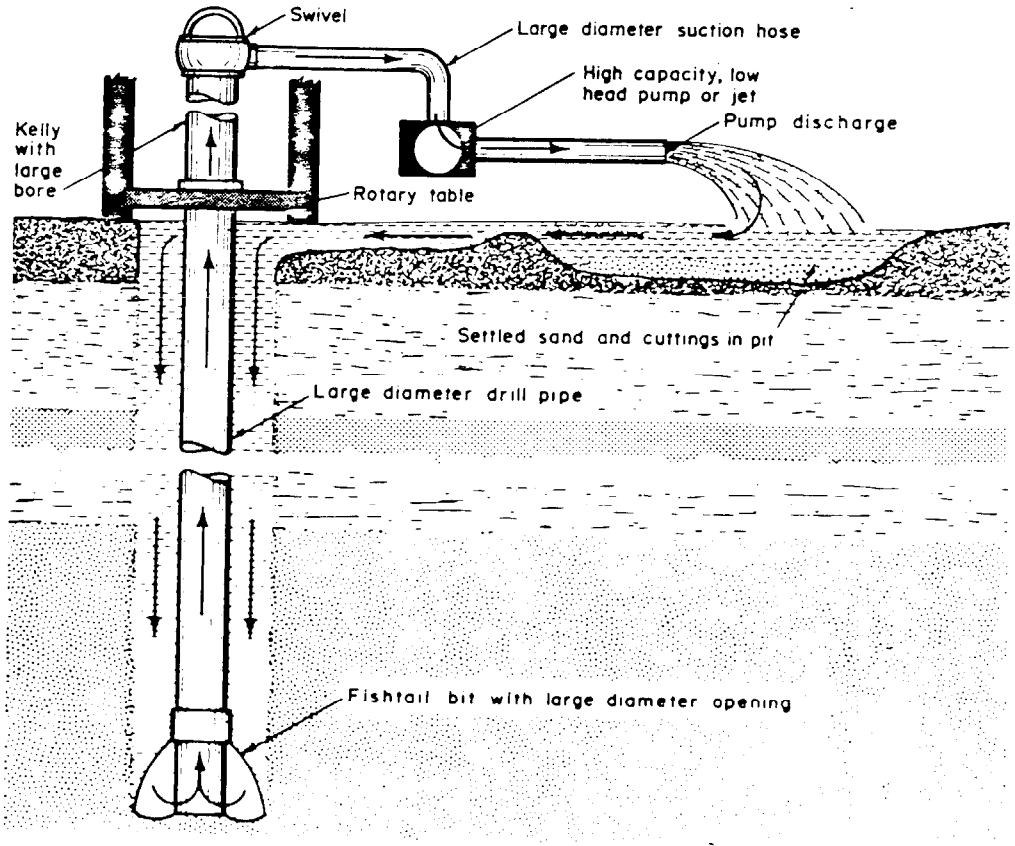

Figure 3.5. Principles of reverse-circulation rotary drilling (Johnson Division, UOP, Inc., 1975)

Reverse-circulation drilling is an inexpensive method, especially when making large diameter holes [up to 60 inches (1.5 m)]. Favorable conditions for the use of this method include drilling in sand, silt or clay, and in areas where the static water level is 10 feet (3.04 m) or more below the ground surface (Campbell and Lehr, 1973; Johnson Division, UOP, Inc., 1975).

3.1.4 Other Drilling Techniques

Other drilling techniques, both conventional and experimental, are used to drill injection wells. Several adaptations of the conventional rotary operation used are air-rotary, foam-rotary, mist-rotary, air-percussion rotary, and jet drilling. The primary objective of using air-drilling, foam-drilling, or mist-drilling fluids is to increase penetration rates. The addition of percussion techniques to conventional rotary rigs also increases penetration rates which generally lowers drilling costs.

Novel techniques are primarily used for special situations and many are still in the experimental stages. These methods have been introduced to drill more efficiently, more rapidly, and more economically. The experimental techniques include turbodrilling; electrodrilling; chemical, explosion, implosion and erosion drilling; pellet and modified turbine; electric arc; electron beam; forced flame; jet piercing; laser; plasma; spark; ultrasonic; and electrohydraulic drilling (Campbell and Lehr, 1973). It is beyond the scope of this chapter to evaluate these techniques; however, these methods may prove to be effective and popular in future injection-well drilling.

3.2 DRILLING PROBLEMS

Many serious problems including deviated holes, lost circulation of drilling fluids, hole sloughing, and well kicks may be encountered during drilling. Any one of these problems can lead to several other problems if allowed to go unchecked (Society of Petroleum Engineers of AIME, 1973, rev. ed.; Moore, 1974; and Petroleum Extension Service, 1975, rev. ed.). Prevention and alertness is stressed as the best practice for limiting drilling problems.

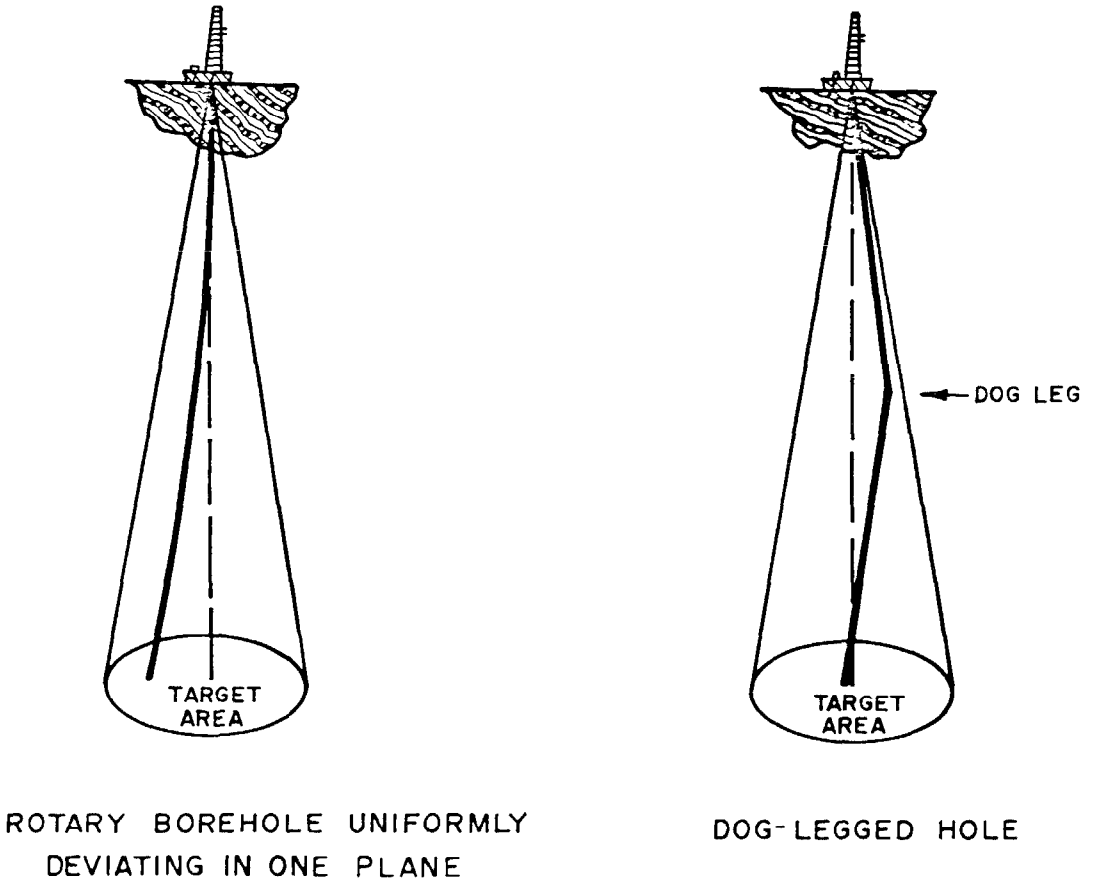

Figure 3.6. Examples of borehole deviations (Petroleum Extension Service, 1968)

Drilling fluid chemistry, fluid pressure, and casing programs are variables used to control drilling problems, yet ultimately the physical characteristics of the site will dictate the measures to be used.

3.2.1 Deviated Holes

It is generally recognized that no borehole is perfectly straight but all have deviations from the vertical. Deviated holes normally do not pose problems to well construction or to cementing unless there are sudden changes in angle and angle direction. These abrupt changes are termed dog-legs and can be so severe that casing cannot be run into the hole, geophysical logging cannot be performed, and stuck drill pipe (keyseating) can occur. Drilling operations in such holes can cause severe wear on the drill pipe, drill collars, and casing which can result in fatigue failures. Severely deviated holes can pose problems with well completion such as gravel packing, cementing, and remedial operations. Figure 3.6 illustrates the difference between uniformly deviating holes and a dog-legged hole.

Directional surveys are run to determine the amount and direction of deviation, but total deviation is not nearly as important as the changes in angle direction over short distances in the borehole. Multishot directional surveys and gyroscopes have been developed to provide information concerning both angle and direction of the borehole.

3.2.2 Lost Circulation

One of the most common problems in rotary drilling is lost circulation of the drilling fluid. Lost circulation can occur at any depth where total pressure exerted by the drilling fluid exceeds the formation pressure. Drilling fluids then migrate into the formation. If circulation is not reestablished, drilling may stop because cuttings are not removed, the hole collapses, or the drill bit cannot cut new hole because it is not lubricated. This problem occurs in various environments including cavernous rocks, very coarse and permeable sand and gravel, naturally fractured

formations, or formations which are fractured by the hydrostatic pressure of the drilling fluid. Both Moore (1974) and the Petroleum Extension Service (1975, rev. ed.), provide detailed information concerning circulation losses in various geologic environments.

Common solutions to lost circulation in shallow formations include changing the drilling fluid properties by using flocculating agents such as lime, or cement; chemical additives such as polymers, soda ash, and sodium hydroxide; or inert fillers such as sawdust, cotton seed hulls, nut shells, or cellophane. Coarse materials such as shells, etc., added to the drilling fluid can help plug the formation openings which are taking fluid. In severe cases of lost circulation, the entire zone may be cemented or cased to prevent further losses (Moore, 1974; Petroleum Extension Service, 1975, rev. ed.).

3.2.3 Hole Sloughing

Sloughing typically occurs in shale and clay formations when the formation pore pressure exceeds the hydrostatic pressure within the borehole, or when there is turbulent flow in the annulus which promotes sidewall erosion (Moore, 1974). Problems associated with hole sloughing include keyseating, hole enlargement, excessive build-up of solids in the drilling fluid, and hole bridging (Warner and Lehr, 1977). Sloughing of the borehole wall tends to increase drilling fluid volumes and can also cause difficulties in successfully logging the borehole (Petroleum Extension Service, 1975, rev. ed.).

To prevent sloughing or limit its adverse effect to borehole stability, lime or gypsum may be added to the drilling fluid. Oil-emulsion and oil-based drilling fluids can be used to limit water hydration of the clay minerals.

Drilling-fluid density may be increased to add wall support (Warner and Lehr, 1977). Increasing the circulation rate of the drilling fluid provides more rapid removal of clay or shale solids.

Hole enlargement can also occur in soluble evaporite formations. A common method for preventing this problem is the use of salt-saturated drilling fluids (Warner and Lehr, 1977).

3.2.4 Well Kicks

A kick occurs whenever formation pore pressure exceeds hydrostatic pressure and is great enough to raise the drilling fluid to the surface. Kicks can occur during all stages of well construction including completion, remedial operations, or servicing. A kick that is not controlled can result in a blowout causing fluid flow from the well. Well blowouts can be dangerous to drilling personnel and can sacrifice the integrity of the well. The general causes of blowouts include insufficient drilling-fluid weight, failure to keep the borehole filled with fluid, swabbing effects (pressure surges caused by running drill pipe or casing), lost circulation, or thinning of drilling fluid by gas or water (Moore, 1974; Society of Petroleum Engineers of AIME, 1973, rev. ed.).

Warning signals alert the crew to implement actions to prevent a blowout. Warning signals include any of the following: (1) well kicks; (2) sudden increase in drilling rates; (3) increase in fluid volume at the surface; (4) decrease in pump pressure and increase in pump speed; (5) continued drilling-fluid flow after the pump is shut down; (6) formation gas or water in the drilling fluid; or (7) proper volumes of replacement drilling fluid not accepted in the borehole as the drill string is pulled out.

Procedures for control of well kicks and blowouts necessitate proper surface equipment including chokes, back-pressure valves, and blowout preventers. Kicks while running or pulling pipe can be eliminated by reducing the rate of pipe movement or by pumping a safety margin of fluid into the hole to compensate for withdrawn pipe volume (Petroleum Extension Service, 1975, rev. ed.).

3.3 WELL-COMPLETION TECHNIQUES

The geology of the site dictates whether the well must be screened or perforated through the injection zone to keep out unconsolidated sediments, or whether the well can be an open-hole completion. Following the decision on the type of well completion, the method of drilling is chosen, and the depth and size of the well is then determined. The size and type of casing is determined by starting

with the injection casing at the bottom of the well and working up to the surface.

Figure 3.7 depicts the various steps in well construction. Step 1 shows the bit ready to break ground (spudding), and Step 2 shows the hole being drilled by the rotary method. The first string of casing is lowered into the borehole and cemented into place by pumping a cement slurry through the bottom of the casing and up the annulus (Step 3). The cement is allowed to harden.

If other casings are put deeper in the hole, a smaller diameter drill bit is inserted and the hole is drilled deeper (Steps 4 and 5). A smaller diameter casing is placed in the borehole and cemented (Step 6). Following the hardening of the cement, a smaller diameter drill bit is inserted and the plugs are drilled out (Step 7). The well is drilled to a depth where the next casing will be placed (Step 8).

The drilling, casing, and cement program continues until the injection interval is drilled out. The injection interval is either screened, or the casing is perforated, or an open hole is drilled in the formation. Downhole equipment is installed and injection operations are initiated. Deep injection wells commonly have several casings cemented in the borehole. Figure 3.8 shows the various casing types and typical depths for setting casing.

3.3.1 Casing Selection

The selection of casing size and casing material is determined before drilling is begun. Casing selection is influenced by several variables including the setting depth, total diameter of drilled well, formation temperature and pressure, and quantity and chemical quality of injected fluid.

Casing is used to prevent the hole from caving, and when cemented properly, to prevent contamination of underground sources of drinking water, to confine injection fluids to the borehole, and to provide a method of controlling injection pressure (Warner and Lehr, 1977). Of primary concern in casing selection is the ability of the

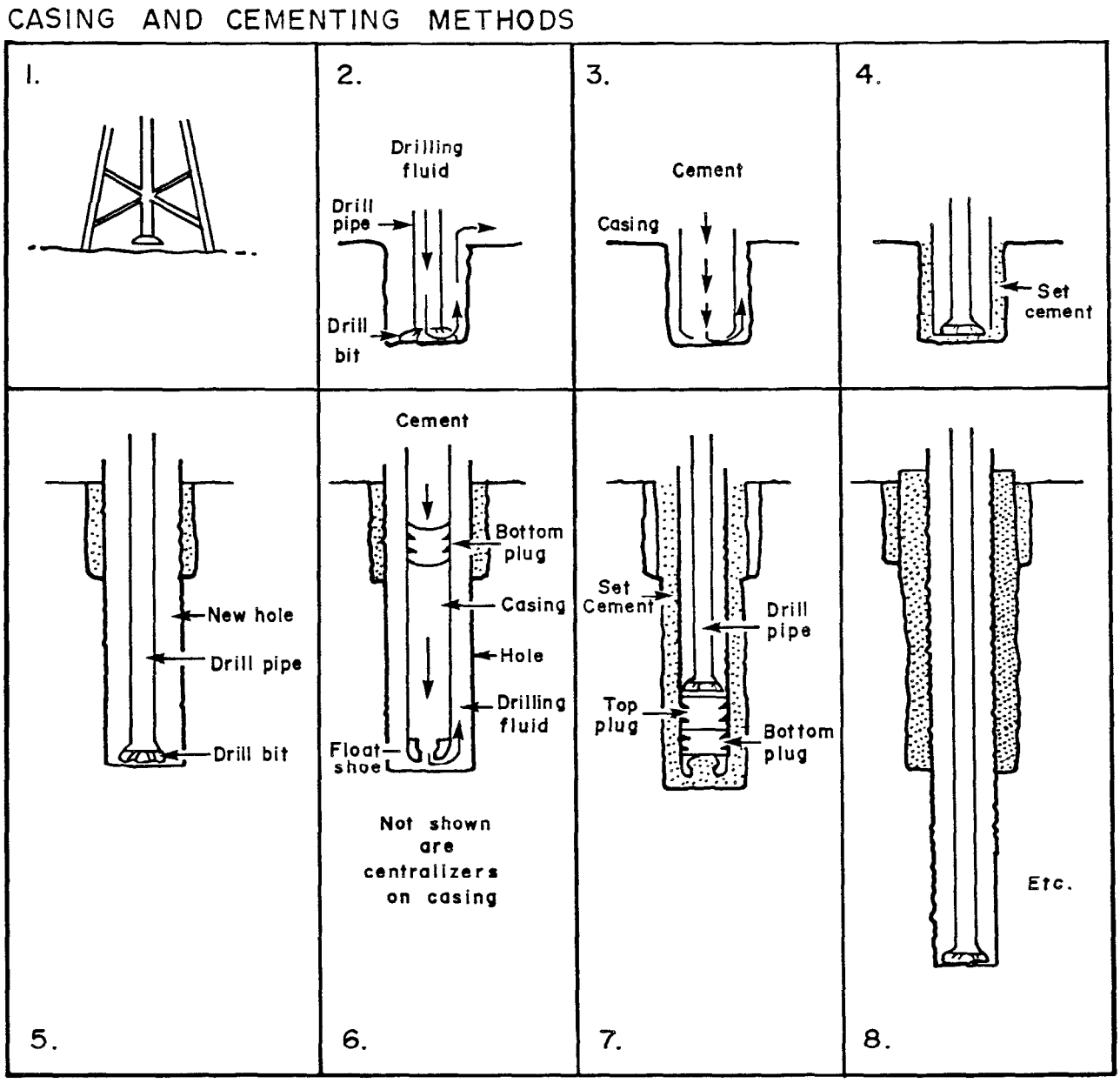

Figure 3.7. Principles of casing and cementing a borehole (Clement and Parker, 1977)

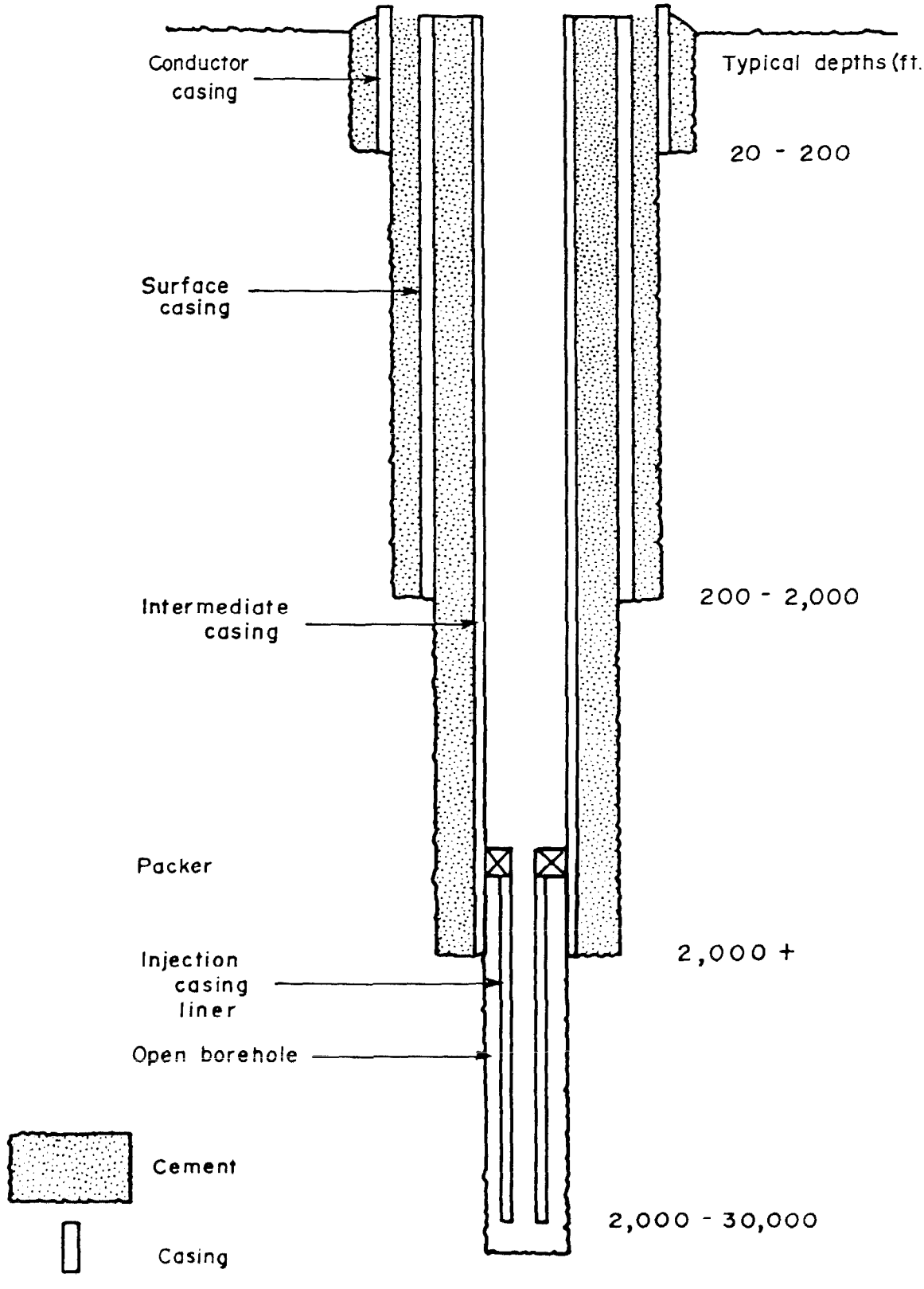

Figure 3.8. Well casing program and typical depth of setting different casings

casing to withstand the forces of internal pressure, external pressure, and axial loading or tension (Smith, 1976; Petroleum Extension Service, 1978; Warner and Lehr, 1977). The strength of the casing must be considered during insertion into the borehole (running), during the transference of weight from the derrick to the wellhead (landing), and during cementing operations.

Smith (1976) reports that lengths of casing (strings) are designed with a safety factor of 1.5 to 1.8 for tensile strength, 1.0 to 1.25 for internal pressure stress, and 1.125 for collapse stress. Computer programs are available from manufacturers for use in the design of casing strings which consider the influencing factors mentioned above (Smith, 1976). Warner and Lehr (1977) provide mathematical equations and steps to determine internal pressure, external collapse pressure, and maximum allowable suspended weight in the borehole.

Many injection wells, especially Class I and Class II wells, are completed with more than one string of casing cemented in the hole. Three casing strings are commonly used, the surface string, one or more intermediate strings, and the injection string. Conductor pipe and liner strings may also be used. The various casing strings are described below.

Conductor Casing

Conductor casing is used to stabilize the top of the borehole to prevent washing out around the base of the rig; it can also serve as a conduit to raise circulating fluid for return to the pit and it can be used for the attachment of a blowout preventer. Conductor pipe may serve to protect lower casing strings from corrosion and to support some of the well head load in areas of inadequate ground support (Petroleum Extension Service, 1978). This string of casing may be installed by driving and may not be cemented in the hole. Common pipe and hole sizes are 16-inch (40.6 cm) pipe in a 20-inch (50.8 cm) hole and 20-inch (50.8 cm) pipe in a 26-inch (66.0 cm) hole (Clement and Parker, 1977).

Surface Casing

When conductor pipe is not used in a well, the surface casing is usually the string of casing set in the hole to protect the well from caving by unconsolidated sediments and to protect fresh-water aquifers from injection-fluid contamination. The setting depth of the surface casing may be only 200 feet (61 m) or it may be as deep as 4,500 feet (1,372 m)(Petroleum Extension Service, 1978). The surface string must be deep enough to reach competent formations which will not fracture or break down from the optimum density of drilling fluid needed to reach the intermediate casing depth or the bottom of the hole. Common diameters of surface casing are 13-3/8 inch (34.0 cm) casing in a 17-1/2 inch (44.5 cm) hole, 10-3/4 inch (27.3 cm) casing in a 15 inch (38.1 cm) hole, and 9-5/8 inch (24.5 cm) casing in a 12-1/4 inch (31.1 cm) hole (Clement and Parker, 1977). These diameters will vary depending upon bottom-hole diameters and bit sizes, tubing sizes, the diameter of workover equipment, and the nature of the formations penetrated.

Intermediate Casing

Intermediate casing strings are used to protect the hole by sealing off weak formations that could fracture from the use of heavy drilling fluids. This string is especially important for protecting against lost circulation in shallower formations and it can be used to block off high pressure zones to allow the use of lighter drilling fluids deeper in the borehole. Common pipe and hole sizes are 9-5/8 inch (24.5 cm) casing in a 12-1/4 inch (31.1 cm) hole, 8-5/8 inch (21.9 cm) casing in a 12-1/4 inch (31.1 cm) hole, or 7-3/4 inch (19.7 cm) casing in a 9-1/2 inch (24.1 cm) hole (Clement and Parker, 1977).

Injection Casing

The injection casing is the last string of casing set. This string protects other formations from the injection fluids and can house the tubing and packer if tubings are used to inject fluids (see Chapter 5). This string is

cemented to ensure a pressure-tight bond around the casing. The injection casing is usually subjected to the greatest pressures in the well and consequently is constructed of the strongest material. The injection casing is set through or to the top of the injection zone. Common casing and hole sizes are 7-5/8 inch (19.4 cm) in a 9-1/2 inch (24.1 cm) hole, or 5-1/2 inch (14.0 cm) casing in a 7-7/8 inch (20.0 cm) hole (Clement and Parker, 1977).

Shyrock and Smith (n.d.) suggest two to three inches (5.1 to 7.6 cm) of additional borehole diameter around the casing couplings for all casing strings, to allow the development of adequate cement sheath around the pipe. Specific details on casing materials and strengths are presented in Cnapter 4.

Liner

From the bottom of the intermediate casing to deeper parts of the well, hangs a section of casing that is called a liner. Liners are not always used, but are advantageous due to lower costs of shorter casing strings. Liner size depends upon the number to be set and the size of the injection equipment to be used. Common liner and hole sizes are 8-5/8 inch (21.9 cm) casing in a 9-1/2 inch (24.1 cm) hole, 7 inch (17.8 cm) casing in an 8-3/4 inch (22.2 cm) hole, 5-1/2 inch (14.0 cm) casing in a 6-3/4 inch (17.1 cm) hole, 5 inch (12.7 cm) casing in a 6-1/2 inch (16.5 cm) hole, and 4-1/2 inch (11.4 cm) casing in a 6-1/8 inch (15.6 cm) hole (Clement and Parker, 1977).

3.3.2 Casing Installation

The casing and cementing lesson published by the Petroleum Extension Service (1978) provides a thorough, step-by-step discussion of casing installation including information on casing design, field handling and maintenance of casing, hole preparation, casing tools, and associated problems. The following discussion is adapted from that paper.

Drill pipe will generally be out of the hole for 12 to 24 hours while logging surveys are performed. During

this time, the hole may have sloughed and bridged preventing running of casing. Also, the drilling fluid may have formed a cake on the walls which can cause casing strings to stick, creating conditions for a poor cementing job, increasing well cost for squeeze cementing, or leading to redrilling. It is good practice to recondition the borehole after logging by running drill collars and a used bit into the hole to clear bridges. The drilling fluid is then circulated at least twice to clean out the borehole.

Casing is installed in stages where there is more than one string. The general procedure begins by suspending the casing lengths from the derrick. The threads are cleaned and lubricated. A guide shoe is attached to the bottom of the first casing length of each string to slip the casing past small ledges of debris in the borehole. The guide shoe is made of heavy steel and concrete.

Centralizers and scratchers are attached outside the casing to aid in the cementing operations. Scratchers are used to clean the borehole of the wall cake to assure a strong bond between the cement and the hole wall. Like the centralizers, the scratchers also help to center the string and to distribute cement uniformly around the casing.

After casing lengths have been joined, the string of casing is run into the borehole. The method generally used for running strings is called floatation. A float collar placed on the bottom lengths of casing keeps drilling fluid out of the casing string and produces the bouyancy necessary to float the casing in a drilling-fluid filled hole. The casing is filled with drilling fluid periodically to limit potential collapse of the string by the high external pressure of the drilling fluid surrounding the pipe.

Casing is run slowly to prevent formation damage and lost circulation from pressure surges. Casings equipped with scratchers and centralizers are generally run more slowly than casings without. Before landing the casing and cementing the string, drilling-fluid is circulated through the casing until wall cake and cuttings stop coming out of the hole.

The transfer of the weight of the casing string from the derrick to the wellhead is referred to as landing the

casing. The casing is attached to the wellhead by a casing hanger which also seals the annulus between the outer and inner strings. To prevent buckling, bursting, collapsing, or stretching the string during landing, the weight transfer usually occurs during the cementing operation. Figure 3.9 shows potential problems associated with improperly landed casing.

3.3.3 Primary Cement Selection

The primary cement is the first cement put into the borehole after the casing string is run. The cement fills the annular space between the casing string or strings and hole wall. The major functions of the primary cement are to restrict movement of fluids between the surface and the subsurface, to support the casing, to prevent pollution of underground sources of drinking water, and to prevent casing corrosion. Table 3.2 presents factors which must be considered when designing the primary cementing program.

A large amount of literature is available on cementing from advances in the petroleum industry. This information should be consulted for additional data concerning cementing methods, additives, equipment, and quality control (Smith, 1976; Allen and Roberts, 1978; Petroleum Extension Service, 1978; Warner and Lehr, 1977).

To prevent contaminating the cement, the borehole is flushed with preflushes to remove wall cake and drilling fluid before cementing the casing. Scratchers may be used to mechanically remove wall cake. Cement functions can be greatly impaired if the drilling fluid (especially those containing special additives) is allowed to mix with the cement slurry.

The selection of cement and cement additives is based on depth and temperature. The additives selected are valuable in allowing the cement to set-up faster, in changing the density and strength of the base cement, in limiting slurry loss to formations, in reducing cost, and in increasing resistance to corrosion. (Cements and cement additives are discussed in Chapter 4.)

The best method for determining the volume of cement necessary is to make a caliper survey of the hole diameter. The Petroleum Extension Service (1978) reports that the

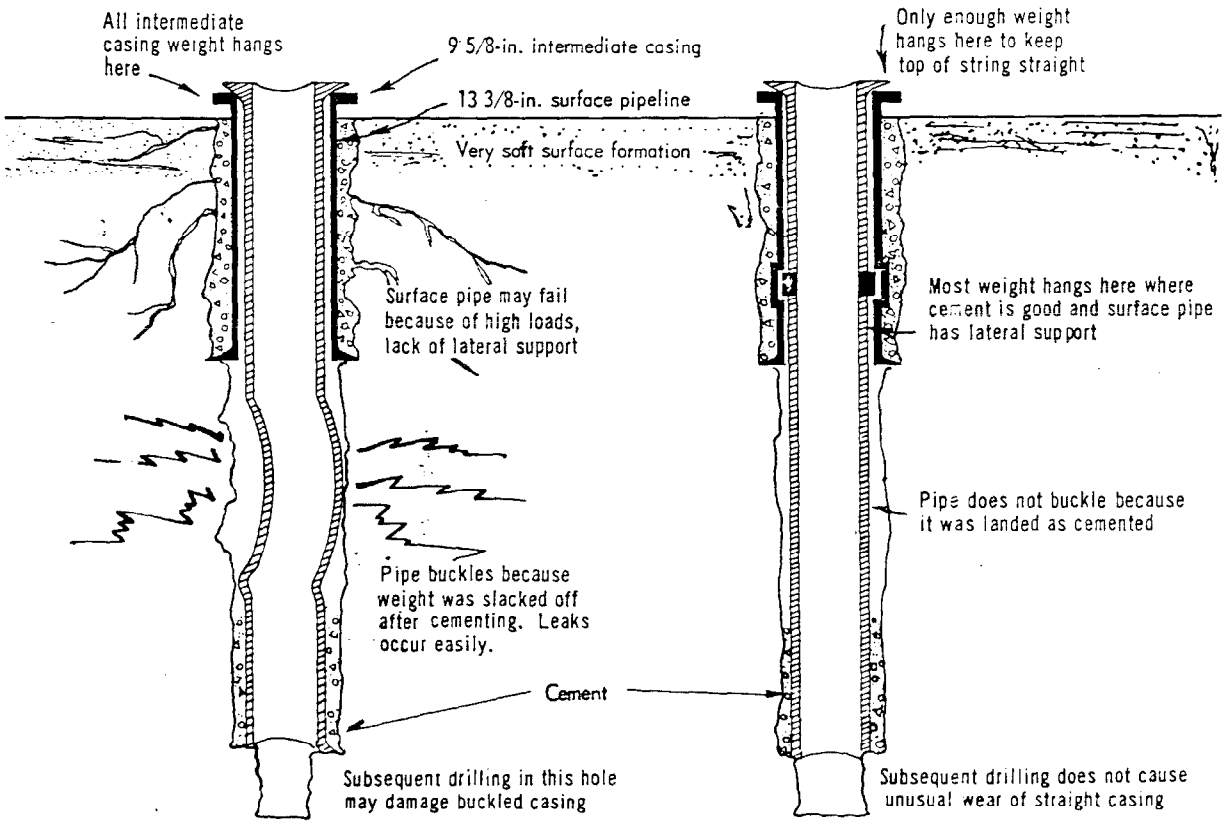

Figure 3.9. Conditions associated with improper and proper methods of landing casing (Petroleum Extension Service, 1978)

TABLE 3.2
ITEMS TO CONSIDER IN PLANNING FOR
PRIMARY CEMENTING
(Smith, 1976)

Factors of Influence
BOREHOLE Diameter, depth, temperature, deviation, formation properties.
DRILLING FLUID Type, properties, weight, compatibility with cement.
CASING Design, size of thread, setting depth, floating equipment, centralizers, scratchers, stage tools.
RIG OPERATIONS Time and rate of placing casing, circulation time before cementing.
CEMENT COMPOSITION Type, volume, weight, properties, additives, mixing, pretesting of well blend with field water.
MIXING AND PUMPING UNITS Type of mixer, cementing head, plugs, spacers, movement during cementing, displacing fluids.

number of barrels of grout per 1,000 feet of hole can be estimated by multiplying the diameter of open hole (in inches) by itself. The outside casing diameter (in inches) is squared and subtracted from the open-hole calculation to yield the general cement requirements of the hole. Frequently, the hole will take more cement slurry than calculated because some cement is lost to the formation.

Water of drinking quality is generally used for mixing cement. A dependable source assures adequate quantities of cement for the well. The temperature of water can influence the mixing and set-up rate of the cement. Additional information on cement mixing is available in the Petroleum Extension Service (1978) and Smith (1976). The density of the cement slurry is generally monitored and recorded throughout the cementing operation to assure that proper water to solids ratio is maintained. The slurry density is usually greater toward the end of the job to permit stronger bonds around the shoe joint.

Cementing plugs are frequently used to separate the cement from any drilling fluid or displacing fluid (Allen and Roberts, 1978) used to place the cement slurry. A bottom plug can precede the cement to clear drilling fluid from the inside of inner casings. A top plug, which serves as a shutoff when the cement is in place and which separates the displacing fluid from the cement, may also be used (Smith, 1976).

Table 3.3 presents several failures that can occur during the cementing operations. Factors which contribute to these failures are also presented in the table.

3.3.4 Primary Cementing Techniques

Various methods are used for cementing well casing. Each may be applied to special situations, but the normal displacement method is the most frequently used. Smith (1976) serves as a basis for the following section in which the various methods are briefly discussed. Figure 3.10 presents the various techniques generally used in primary cementing.

When using the normal displacement method, cement is pumped through the casing and out of the casing shoe into

TABLE 3.3
FACTORS THAT CONTRIBUTE TO
CEMENTING FAILURES
(Smith, 1976)

Type of Failure	Contributing Factor
Premature setting in casing	Contaminants in mixing water. Incorrect temperature estimate. Dehydration of cement in annulus. Use of improper cement. Plugged cement shoe or collar. Insufficient retarder.
Failure to bump plug	Lodging of plug in head. Running of top plug on bottom. No allowance for compression. Incorrect displacement calculations.
Incomplete mixing	Mechanical failure. Insufficient water or pressure. Failure of bulk system.
Gas leakage in annulus	Insufficient hydrostatic head. Gelation at cement/drilling fluid. Failure of cement to cover gas bearing zones. Cement dehydration.
Channeling	Contact of pipe with formation. Poor drilling fluid properties (high plastic viscosity and high yield point).
Too-rapid setting of cement	Improper water ratio. Incorrect temperature assumption. Mechanical failures. Wrong cement or additives for well conditions. Hot mixing water. Slurry allowed to remain static to perform rig operation. Improper choice of drilling fluid/cement spacers.

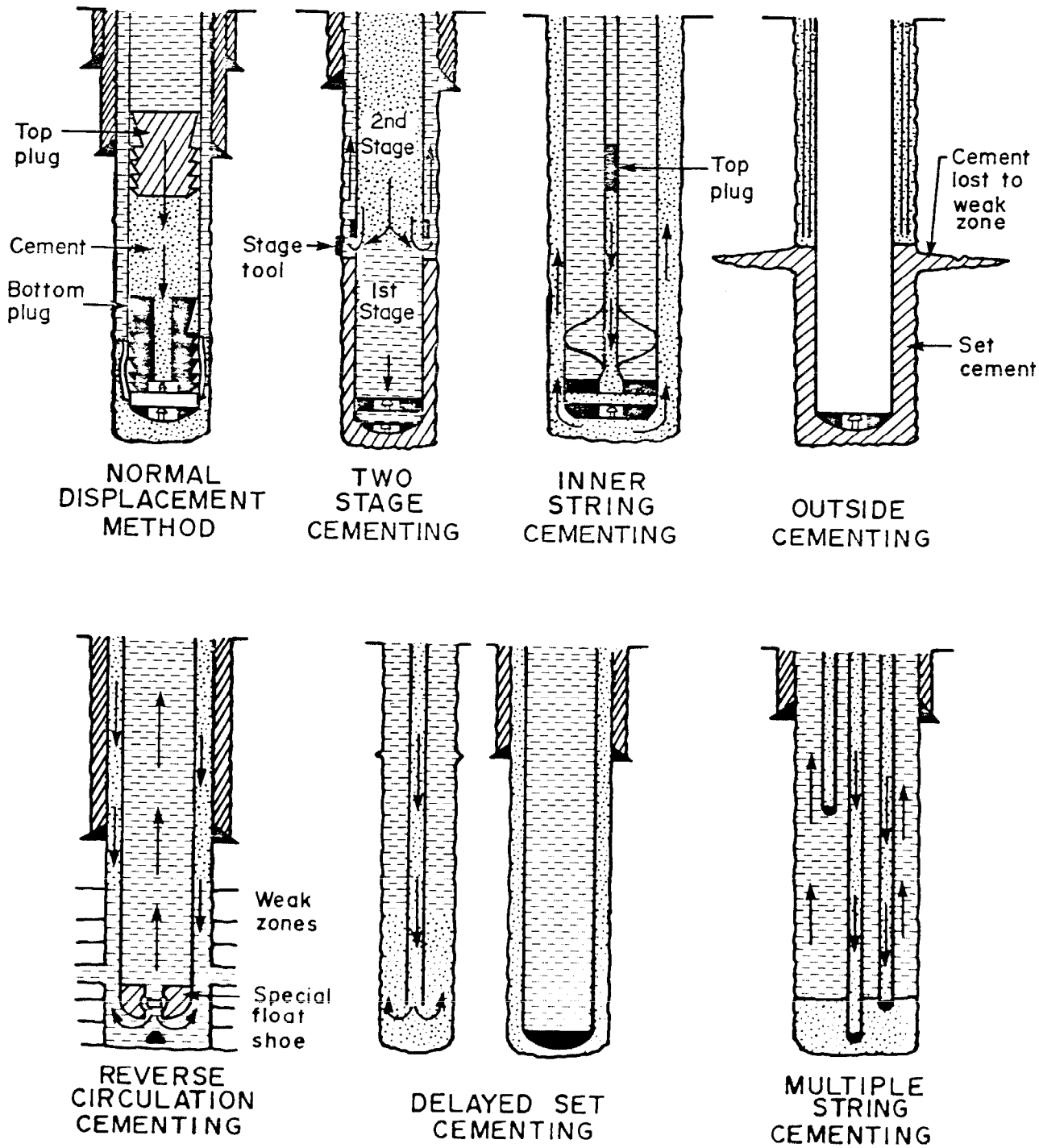

Figure 3.10. Techniques used in primary cementing (Smith, 1976)

the annulus between the casing and borehole wall, or between a larger diameter casing and the casing string being cemented. Special adaptors and continuous cementing heads are used for this single-stage method. All casing strings including the conductor pipe, surface pipe, intermediate strings, and injection string may be cemented with this technique.

The cement slurry is generally mixed and pumped at the fastest possible rate without delays or interruptions to keep the slurry in turbulent flow, to remove wall cake, and thereby, to increase chances for a secure bond to the formation walls. Too much pressure on the casing and surface connections may cause ruptures, however, and too much flow in the annulus may cause formation damage which could contribute to formation loss.

The stage cementing method performs primary cementing in several steps, or stages. It is typically used for wells having critical fracture gradients when weak formations are exposed and will not support hydrostatic head during cementing. Stage cementing is also used in wells requiring long columns of cement. A major disadvantage of stage cementing is the immobility of the casing after the first stage of cementing. This increases the possibility of drilling-fluid channeling and limits the amount of drilling fluid removed from the annulus.

Inner-string cementing, a third method, is used for large diameter casing. Tubing or drill pipe is commonly used as an inner string to pump the cement. This procedure reduces the cementing time and the volume of displacement fluid required to pump the plug. It prevents having to drill out the large volume of cement that a large casing would hold if it has been cemented in the conventional manner.

Remedial work sometimes uses the annulus method of cementing. This technique is commonly used for conductor or surface casing to bring the top of the cement to the surface. This is done by pumping cement through tubing or a smaller diameter pipe run between the casings or between casing and the hole wall.

When it is not possible to pump the cement slurry in turbulent flow without breaking down the weak zones above the casing shoe, the reverse circulation cementing technique

may be used. This method involves pumping the slurry down the annulus and displacing the drilling fluid back up through the casing. It allows for a wider range in slurry compositions, so that heavier, or slow-setting cement, can be placed at the lower portion of casing, and lighter, or accelerated cement, can be placed at the top of the annulus. A major drawback of this method is that the period of drilling fluid displacement cannot be detected from pump pressure. This leads to errors in the calculation of annular volume of required amounts of cement slurry, and of volume of displacing fluid necessary to achieve complete cement placement.

To obtain a more uniform cement sheath around the casing, delayed-set cementing is used. A slow-setting cement slurry containing a filtration-control additive is placed in the borehole before running the casing. The cement is pumped down the drill pipe and up the annulus. The drill pipe is then removed from the well, and the casing is sealed at the bottom and lowered into the unset cement slurry. After the slurry is set, the well can be completed using conventional methods. This technique has been used in tubingless completion wells by placing the slurry down one string and lowering multiple tubing strings into the unset cement.

One disadvantage of this method is that the longer set-up times increase well construction costs. Cements used in the delayed-set technique usually contain 6 to 8 percent bentonite and a dispersant to control filtration. Adequate quantities of retarder are used to delay setting time for 18 to 36 hours. (See Chapter 4 for further information).

Special problems encountered during cementing include problems intrinsic to high temperature zones, gas zones, soluble formations, deep wells, geothermal wells, steam injection wells, deviated wells, and wells using multiple strings (Allen and Roberts, 1978; Smith, 1976). These problems are discussed as they apply to specific types of injection wells in Chapters 8, 9, and 10.

3.3.5 Secondary Cementing Methods

Secondary cementing is used when leaks develop in primary cement or when abandoning operations are needed.

Oil-well literature provides a great deal of information on these procedures (Clement and Beirute, 1977; Allen and Roberts, 1978; Smith, 1976)

Squeeze cementing is a remedial method in which a cement slurry is forced into a formation or into an area in the annulus to fill perforations, to repair casing holes, to seal leaking liner tops, to seal lost circulation zones, to supplement primary cementing jobs, or to abandon holes. A typical squeeze operation is presented in Figure 3.11.

There are two general methods in squeeze-cementing operations, high and low pressure techniques. The high pressure technique involves formation fracturing while pumping the cement slurry under pressure. This technique has many disadvantages, including high fluid loss, making the low pressure technique more desirable (Figure 3.12) and more commonly used. Low fluid-loss cement is pumped into the perforated zone and sufficient pressure is applied to form a cake of dehydrated cement in the perforations (Figure 3.13). Final squeeze pressures are recommended to be 200 to 300 psi (1.38×10^6 to 2.0×10^6 N/m^2) less than formation fracture pressures (Allen and Roberts, 1978). In addition, Allen and Roberts note that a full column of 15.5 lb/gal (1.88 kg/l) cement frequently exerts enough pressure to fracture the formation with no additional surface pressure.

Squeeze operations begin when cement is spotted over perforations in the casing using tubing and packers. Pressure is added with occasional hesitations (refer to Figure 3.14) to dehydrate cement in perforations. After the final pressure is reached, the pump is shut down to assure no pressure bleed-off. Reverse circulation of cement may then be used to wash out excess cement from perforations.

Fractured and vugular formations and long perforation sections present the most severe squeeze problems. Long perforation intervals [over 50 feet (15.2 m)] are difficult to squeeze successfully in one operation because the top perforations tend to seal off faster than deeper perforations, a result of cement dehydration. Water is squeezed out of the cement slurry and wall cake forms. Such differential dehydration is successfully combated by use of high fluid-loss cement (Clement and Beirute, 1977). Vugular, carbonate formations and highly fractured rocks accept

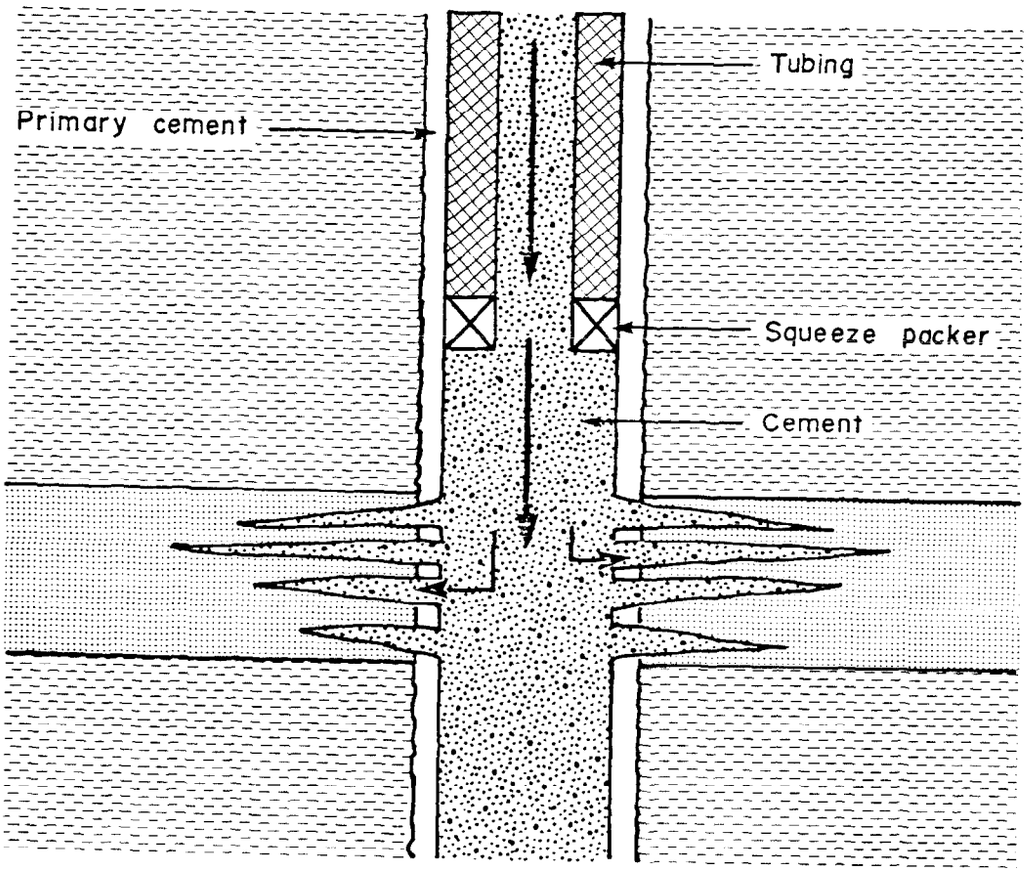

Figure 3.11. Squeeze-cementing operation using packer to control pressure and flow (Smith, 1976)

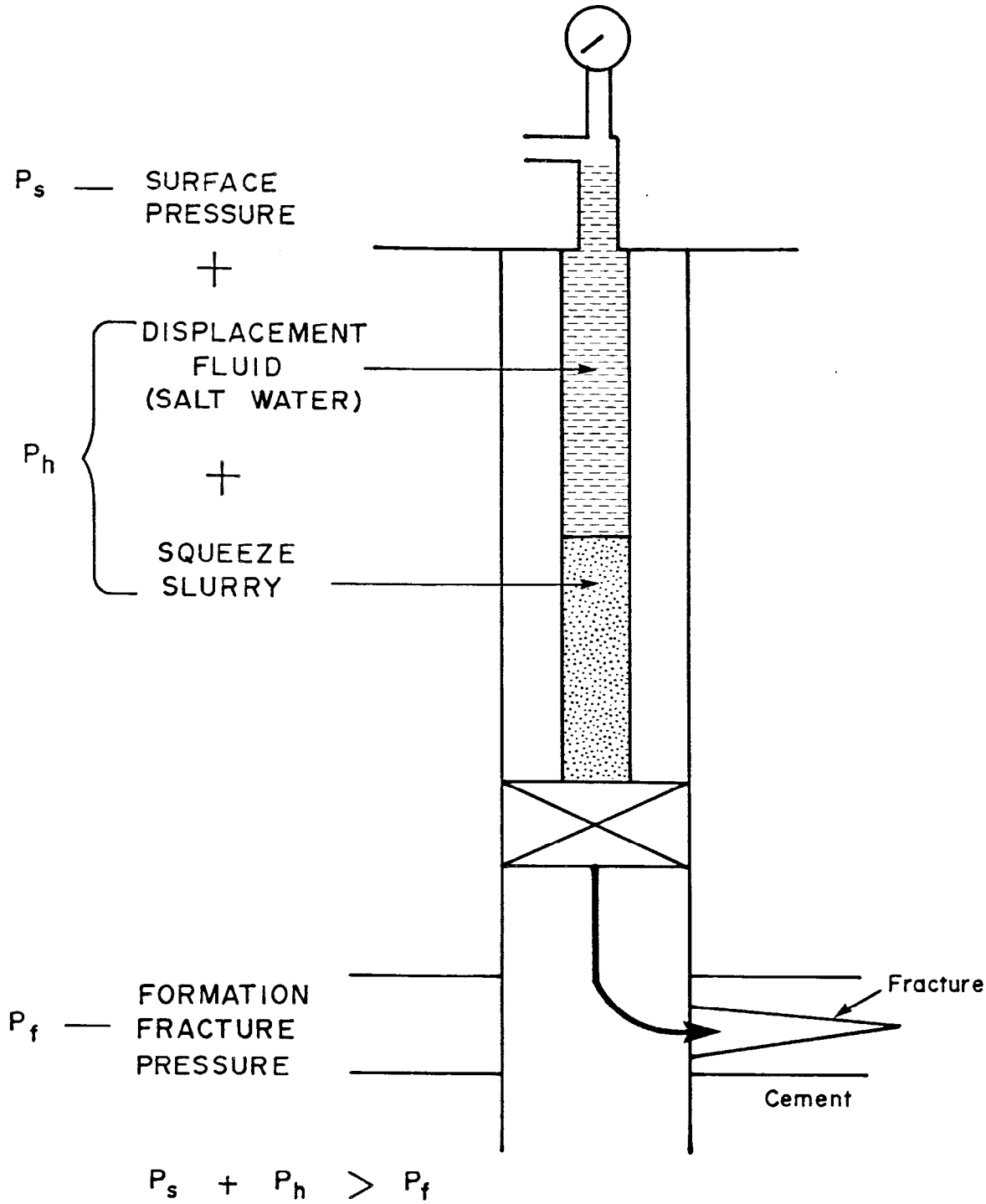

Figure 3.12. Principles of high-pressure squeeze cementing (Smith, 1976)

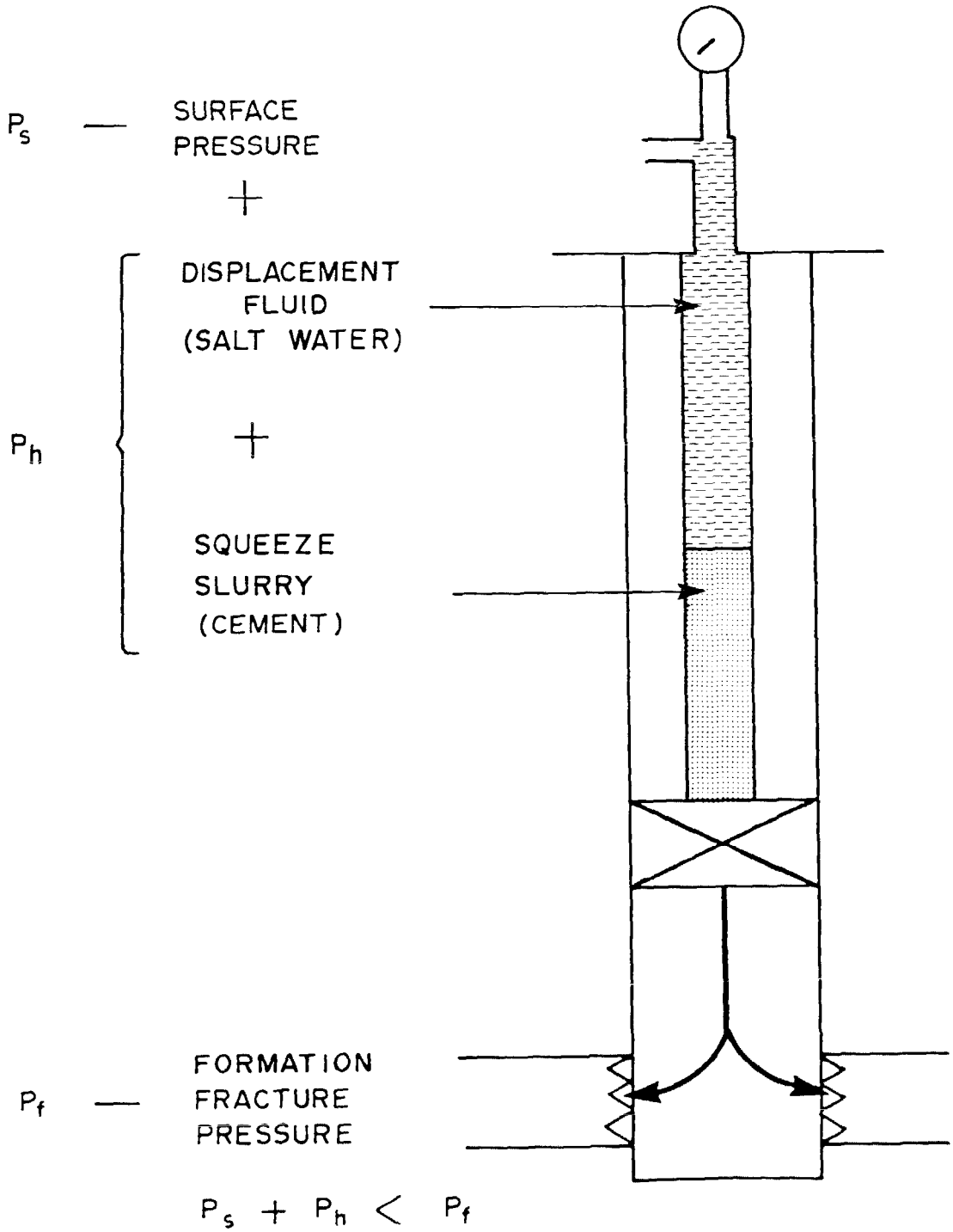

Figure 3.13. Principles of low-pressure squeeze cementing (Smith, 1976)

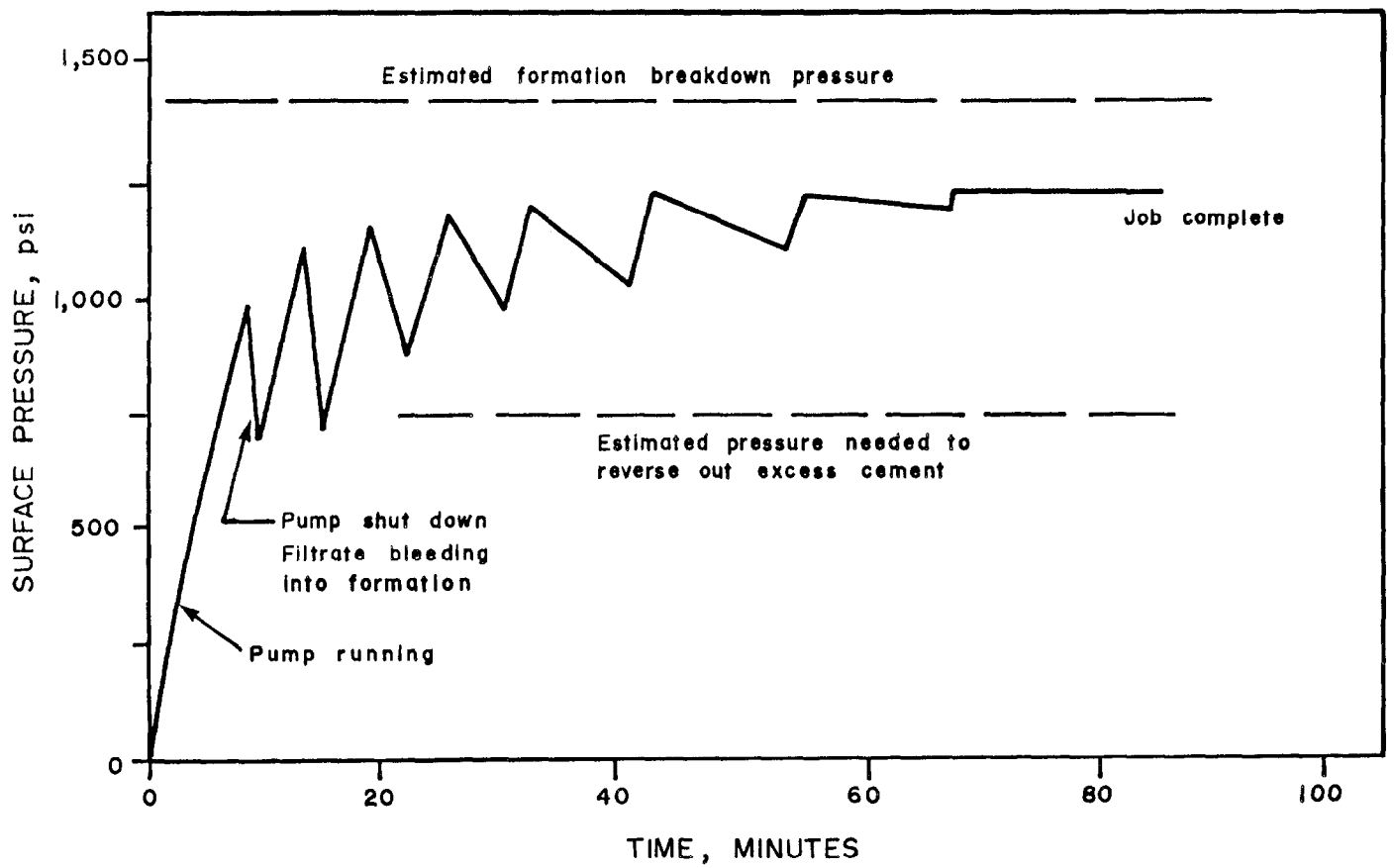

Figure 3.14. Generalized pressure-recording chart for squeeze cementing using the hesitation technique (Allen and Roberts, 1978)

large volumes of cement without adequate support for cement slurries to bridge against. Thixotropic cements are often used in these situations.

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4. CONSTRUCTION MATERIALS

In completing injection wells, materials of sufficient strength and durability can be selected that will insure the mechanical integrity of the well and thereby prevent environmental degradation and economic loss. Construction materials used for completing injection wells are generally classified into three groups which include: casings (tubular goods), cements and cement additives, and ancillary equipment and materials such as centralizers, scratchers, and annulur fluids. Other equipment and materials such as packers, valves and fittings, screens, and drilling fluids are described in Chapters 3 and 5.

4.1 CASING

Casing is the pipe material placed inside the borehole that transmits fluids through the well into the injection zone. Casing is usually distinguished from tubing with respect to its function and its location in the well. Casing refers to the outer pipe string, often cemented in place to maintain structural integrity in the borehole (see Figure 4.1). Tubing usually refers to the innermost pipe string through which injection usually takes place. It is often separated from concentric strings of casing by an annulur fluid and can be removed easily from the well. However, in tubingless completions, the innermost casing can also be referred to as the injection casing.

The primary functions of casing are to prevent the hole from caving, to confine the injection fluid to the well, to prevent contamination of underground sources of drinking water, and to provide a method of pressure control. In completing injection wells, four types of casing may be used, but may not always be necessary. These include: conductor casing, surface casing, intermediate casing, and injection casing (see Chapter 3 for more details on casing strings).

The selection of casing used in completing an injection well is generally based on internal and external pressure on the well, axial loading (compressive and tensile stresses) exerted on the well, temperature of injection fluid and well environment, and corrosive action of injection fluids

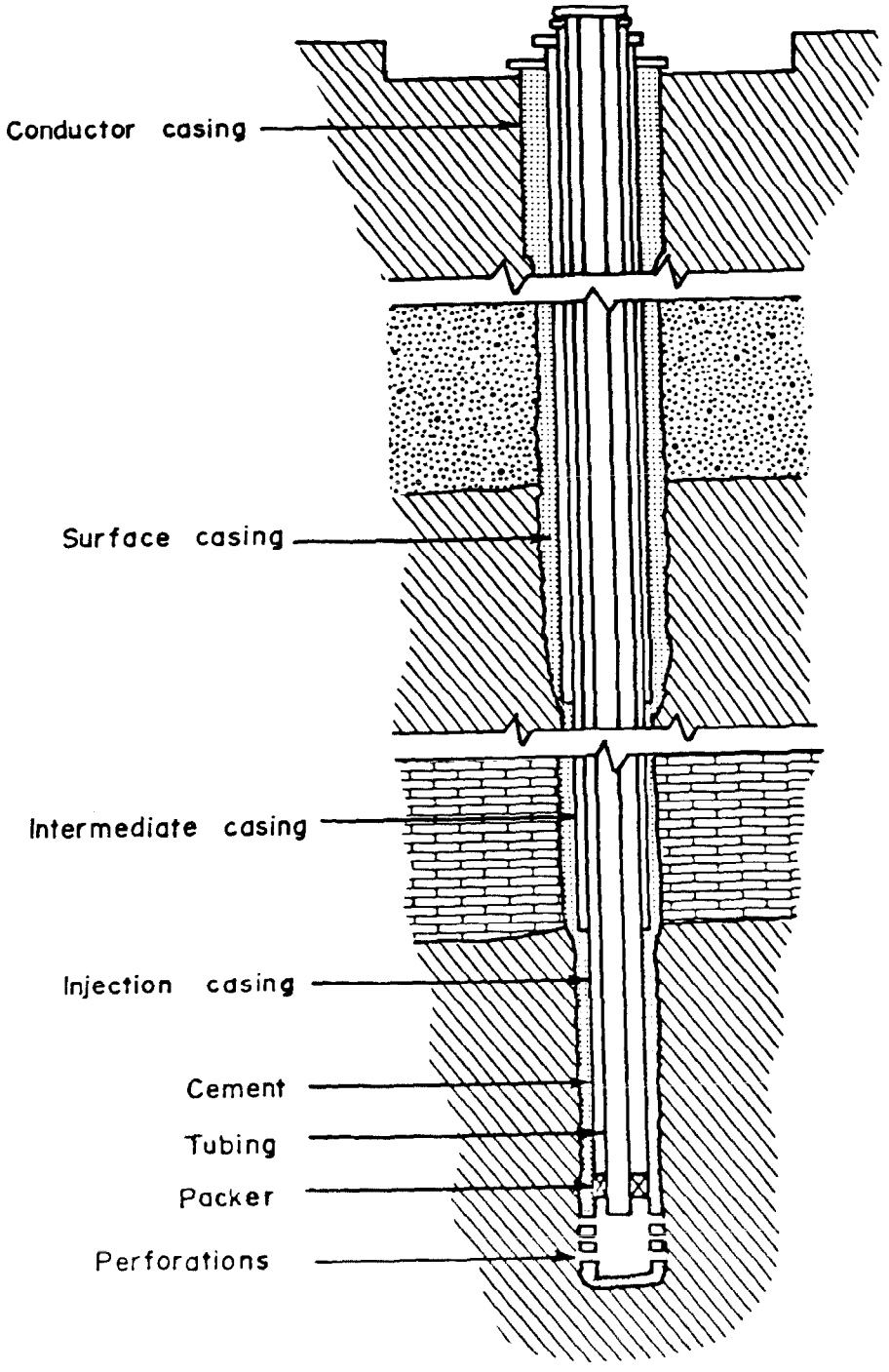


Figure 4.1. Casing and cementing program for a Class I injection well

and/or fluids or formations surrounding the well. Any or all of these stresses, if incompatible with casing characteristics can cause failure of the well and subsequent release of injection fluids into surrounding formations or underground sources of drinking water. Internal pressure can cause the casing material to burst, while external pressure can result in collapse of the pipe body. Compressive stresses, as a result of buoyancy or tensile stresses due to the hanging weight, can cause joint failure. In addition to physical stresses, corrosion can be the primary cause of mechanical-integrity failure of the well (Warner and Lehr, 1977; Allen and Roberts, 1978).

Every injection well is exposed to some degree of corrosion. Generally, it is impossible or too expensive to completely control all corrosion. However, from a material selection viewpoint, there are steel alloys and nonmetal casings available which may improve the ability of the injection well to resist corrosion (see Chapter 6 for a detailed discussion of corrosion and its control).

The physical properties of casing, including collapse resistance, internal yield pressure, joint yield strength, and pipe-body yield strength, are of primary importance in determining performance. These properties affect the ability of the injection well to maintain mechanical integrity. Collapse resistance and internal-yield pressure are critical in determining the ability of the casing to withstand external and internal pressures exerted on the pipe, respectively. Similarly, joint-yield strength and pipe-body yield strength determine the ability of casing to withstand axial loadings exerted on the pipe body.

4.1.1 Steel Casing

The most commonly used material for casing is steel. Table 4.1 lists several grades of steel as specified by the minimum yield strength of the material by the American Petroleum Institute (API). The API has also developed specifications for the chemical characteristics of casing which include the requirement that the material be made from open-hearth, electric furnace, or basic oxygen steel with maximum allowable percentages of phosphorus (0.040 percent) and sulfur (0.060 percent) [API Specification 5A (1979), 5AC

TABLE 4.1
API YIELD-STRENGTH SPECIFICATIONS FOR VARIOUS GRADES OF STEEL CASING AND TUBING
(API SPEC 5A, 1979; 5AC, 1979; 5AX, 1976)

Grade	Yield Strength (psi) Min.	Max.
H-40	40,000	80,000
J-55	55,000	80,000
K-55*	55,000	80,000
C-75	75,000	90,000
L-80	80,000	95,000
N-80	80,000	110,000
C-95*	95,000	110,000
P-105	105,000	135,000
P-110*	110,000	140,000

* Specifications apply to use of this grade of material for casing only.

(1979) and 5AX (1976)]. For restricted yield-strength casing, API has developed more detailed specifications concerning the chemical properties of the material as shown in Table 4.2. In general, metallurgical properties of specific brands are held as proprietary information by the manufacturer and are not sought out by purchasers as a basis for selection. Usually selection is based on the physical properties of the material.

Table 4.3 and 4.4 present detailed descriptions of the performance properties for several grades and sizes of standard API pipe. The joint-yield strengths presented in Table 4.3 assume a standard API eight-round thread-type joint. However, yield strengths may vary if other couplings such as buttress or extra clearance couplings are used.

Figure 4.2 shows the standard API coupling connections used in joining steel casing. The different types of API couplings include:

1. Non-Upset Connection (NU). A coupling wherein the joint has less strength than the pipe body, 10-round thread form (10 threads per inch).

2. External Upset Connection (EUE). A coupling wherein the joint has greater strength than the pipe body, 8-round thread form.

3. Special Clearance Couplings. Standard API couplings which have been turned down to allow more clearance between coupling and outer casing or borehole. Special clearance coupling-type thread forms such as buttress-thread connections have been developed for NU casing which, unlike the API NU connection, have 100 percent joint strength. (Allen, and Roberts, 1978).

4. Integral Joint/Extreme-Line Type Connections. These connections, are of a single male and female type union. Several different types are available which provide extra clearance and sealing characteristics.

All joints must be filled with a thread lubricating compound during make-up. However, several proprietary special joints have been manufactured which rely on a metal-to-metal seal (Armco, 1981).

TABLE 4.2
CHEMICAL (PERCENT) AND HEAT TREATMENT REQUIREMENTS
FOR RESTRICTED YIELD STRENGTH CASING AND TUBING
(API SPEC 5AC, 1979)

Grade	Type	Carbon		Manganese		Molybdenum		Chromium		Nickel	Copper	Phosphorus	Sulfur	Silicon	Heat Treatment
		min.	max.	min.	max.	min.	max.	min.	max.	max.	max.	max.	max.	max.	
C-75	1	...	0.50	...	1.90	0.15	0.40	*	*	*	*	0.04	0.06	0.35	Normalized and tempered
C-75	2	...	0.40	...	1.50	...	...	...	...	...	...	0.04	0.06	0.35	Quenched and tempered
C-75	3	0.38	0.48	0.75	1.00	0.15	0.25	0.80	1.10	...	...	0.04	0.06	...	Normalized and tempered
L-80	...	...	0.40	...	1.90	...	...	...	...	0.25	0.35	0.04	0.06	0.35	Quenched and tempered
C-95	...	...	0.45	...	1.90	...	...	...	...	...	...	0.04	0.06	0.35	Quenched and tempered

* For Grade C-75, Type 1, chromium, nickel and copper combined shall not exceed 0.50 percent.

TABLE 4.3
MINIMUM PROPERTIES OF CASING
(API SPEC. 5C2, 1980)

DIMENSIONS						MINIMUM COLLAPSE PRESSURE (psi)						MINIMUM INTERNAL YIELD PRESSURE (psi)						JOINT YIELD STRENGTH (1000 LBS)												
																		SHORT THREAD								LONG THREAD				
OD SIZE (IN.)	WEIGHT PER FOOT NOM (LBS)	WALL THICKNESS (IN.)	ID (IN.)	DRIFT (IN.)	COUPLING OD (IN.)	H-40	J-55 K-55	C-75	N-80 L-80	C-95	P-110	H-40	J-55 K-55	C-75	N-80 L-80	C-95	P-110	H-40	J-55	K-55	C-75	L-80	N-80	C-95	P-110	J-55	K-55	C-75	L-80	N-80	C-95	P-110
4½	9.50	0.205	4.090	3.985	5.000	2770	3310					3190	4380					77	101	112						162	180	212	212	223	234	279
	10.50	0.224	4.052	3.927	5.000		4010						4790						132	148								257	257	270	284	338
	11.60	0.250	4.000	3.875	5.000		4960	6130	6350	7010	7560		5350	7290	7780	9240	10680		154	170												408
	13.50	0.290	3.920	3.795	5.000			8170	8540	9650	10870			8460	8820	10710	12410															
	15.10	0.337	3.826	3.701	5.000						14320						14420															
5	11.50	0.220	4.560	4.435	5.563		3060						4240						133	147						182	201					
	13.00	0.253	4.494	4.369	5.563		4140						4670	7770	8290	9640	11400		189	186						223	248	295	295	311	326	388
	15.00	0.296	4.408	4.283	5.563		5550	6870	7250	8090	8830		5700	8500	10140	12040	13840		207	228								378	374	398	418	495
	18.00	0.362	4.276	4.151	5.563			10000	10490	12010	13450			10140	10810	12840	14870											468	466	490	515	613
	21.40	0.437	4.126	4.001	5.563			11960	12760	15150	17650			10140	10810	12860	14870											538	538	567	596	708
	24.10	0.500	4.000	3.875	5.563			13500	14480	17100	19800																					
5½	14.00	0.244	5.012	4.887	6.050	2630	3120					3110	4270					138	172	188						217	239					
	15.50	0.275	4.950	4.825	6.050		4040						4810						202	222						247	272	327	338	348	374	445
	17.00	0.304	4.892	4.767	6.050		4910	6070	6280	6830	7480		5320	7250	7740	9190	10840		229	262								403	416	428	460	548
	20.00	0.361	4.778	4.653	6.050			8440	8830	10000	11080			8610	8190	10810	13640											473	489	502	540	643
	23.00	0.415	4.670	4.545	6.050			10460	11160	12820	14620			9280	9880	11730	13580															
6 5/8	20.00	0.288	6.049	5.924	7.390	2520	2970					3040	4180					184	245	267						288	280					
	24.00	0.352	5.921	5.796	7.390		4560	5570	5760	6290	6710		5110	6970	7440	8830	10230		314	342						340	372	453	473	481	548	641
	28.00	0.417	5.791	5.666	7.390			7030	8170	9200	10140			8260	8816	10460	12120											552	576	566	665	761
	32.00	0.475	5.675	5.550	7.390			9030	10320	11600	13200			9410	10040	11920	13800											638	666	677	769	904
7	17.00	0.231	6.538	6.413	7.656	1450						2310						122														
	20.00	0.272	6.456	6.331	7.656	1580	2270					2720	3740					178	234	254						313	341	416	435	442	505	
	23.00	0.317	6.366	6.241	7.656		3270	3770	3830	4150			4360	5940	6340	7530			284	308						367	401	488	511	518	583	683
	26.00	0.362	6.276	6.151	7.656		4320	5260	5410	5870	6210		4980	6790	7240	8600	9860		334	384								562	587	597	683	787
	29.00	0.408	6.184	6.059	7.656			6760	7020	7820	8510			7650	8160	9690	11220											633	661	672	768	897
	32.00	0.453	6.094	5.969	7.656			8230	8600	9730	10768			8490	9080	10780	12460											703	734	746	853	998
	35.00	0.498	6.004	5.879	7.656			9710	10180	11640	13010			8660	9240	10970	12700											767	801	814	931	1087
	38.00	0.540	5.920	5.795	7.656			10880	11398	13420	15110			8660	9240	10970	12700															
7 5/8	24.00	0.300	7.025	6.900	8.500	2040						2760						212								348	377					
	26.40	0.328	6.969	6.844	8.500		2880	3280	3490	3710			4140	5650	6020	7150			316	342								461	482	490	560	
	29.70	0.375	6.875	6.750	8.500			4870	4790	5120	5340			6450	6890	8180	9470											542	568	575	659	789
	33.70	0.430	6.765	6.640	8.500			6320	6580	7280	7850			7400	7900	9380	10860											615	664	674	772	901
	39.00	0.500	6.625	6.500	8.500			8430	8810	9880	11060			8610	9180	10900	12620											751	788	798	914	1068
	42.80	0.562	6.501	6.376	8.500			10240	10810	12400	13810			8670	10320	12250	14190											852	892	905	1037	1210
	47.10	0.625	6.375	6.250	8.500			11290	12040	14300	16550			8840	10490	12460	14430											953	997	1013	1159	1353
8 5/8	24.00	0.264	8.097	7.972	9.625		1370						2850						244	283												
	28.00	0.304	8.017	7.892	9.625	1840						2470						233								417	452					
	32.00	0.352	7.921	7.796	9.625	2210	2530					2880	3930					278	372	402						488	528					
	36.00	0.400	7.825	7.700	9.625		3450	4020	4100	4360			4460	6090	6490	7710			434	468								640	678	688	789	
	40.00	0.450	7.725	7.600	9.625			5358	5520	6010	6380			6850	7300	8670	10040											742	776	788	904	1055
	44.00	0.500	7.625	7.500	9.625			6880	6950	7730	8400			7810	8120	9640	11160											834	874	887	1017	1188
	49.00	0.557	7.511	7.386	9.625			8200	8570	9690	10720			8480	9040	10740	12430											939	983	997	1144	1336
9 5/8	32.30	0.312	9.001	8.845	10.625	1460						2270						254								453	489					
	36.00	0.352	8.921	8.765	10.625	1740	2020					2560	3520					294	384	423						570	561					
	40.00	0.395	8.835	8.679	10.625		2570	2980	3090	3330			3950	5390	5750	6820			452	488								694	727	737	847	
	43.50	0.435	8.755	8.599	10.625			3750	3810	4130	4430			5930	6330	7510	8700											776	813	825	948	1108
	47.00	0.472	8.681	8.525	10.625			4630	4750	5080	5310			6440	6870	8150	9440											852	893	905	1040	1213
	53.50	0.545	8.535	8.379	10.625			6380	6620	7330	7930			7430	7930	9410	10900											999	1047	1062	1220	1422
10¾	32.75	0.279	10.192	10.036	11.750	880						1820						205														
	40.50	0.350	10.050	9.894	11.750	1420	1580					2280	3130					314	420	450												
	45.50	0.400	9.950	9.794	11.750		2090						3580						493	528												
	51.00	0.450	9.850	9.694	11.750		2700	3100	3220	3490	3670		4030	5490	5860	6980	8080		565	606	755	794	804	927	1080							
	55.50	0.495	9.760	9.604	11.750			3950	4020	4300	4630			6040	6450	7860	9260				843	884	895	1032	1203							
	60.70	0.545	9.660	9.504	11.750						5860						9760								1338							
	65.70	0.595	9.560	9.404	11.750						7490						10650								1472							
11¾	42.00	0.333	11.084	10.928	12.750	1070						1860						307														
	47.00	0.375	11.000	10.844	12.750		1510						3070						477	509												
	54.00	0.435	10.880	10.724	12.750		2070						3560						588	608												
	60.00	0.489	10.772	10.616	12.750		2660	3070	3180	3440			4010	5460	5830	6920			849	893	869	913	924	1066								
13 3/8	48.00	0.330	12.715	12.559	14.375	770						1730						322														
	54.50	0.380	12.615	12.459	14.375		1130						2730						514	547												
	61.00	0.430	12.515	12.359	14.375		1540						3090						595	633												
	68.00	0.480	12.415	12.259	14.375		1950	2270	2260	2320			3450	4710	5020	5970			675	718	905	952	963	1114								
	72.00	0.514	12.347	12.191	14.375			2590	2670	2820				5040	5380	6390					978	1029	1040	1284								
16	65.00	0.375	15.250	15.062	17.000	670						1940						439														
	75.00	0.438	15.124	14.936	17.000		1020						2630						710	752												
	84.00	0.495	15.010	14.822	17.000		1410						2980						817	865												
18 5/8	87.50	0.435	17.755	17.567	20.000	630	630					1630	2250					659	764	794												
20	94.00	0.438	19.124	18.936	21.000	520	570					1630	2110					581	784	824						807	866					
	106.50	0.500	19.000	18.812	21.000		770						2410						813	980						1057	1113					
	133.00	0.635	18.730	18.542	21.000		1500						3060						1192	1253						1380	1453					

Table 4.4
Tubing Minimum Performance Properties
(Allen & Roberts 1978)

Tubing Size		Nominal Weight			Grade	Wall Thickness (in.)	Inside Dia. (in.)	Threaded and Coupled				Integral Joint		Collapse Resistance (psi)	Internal Yield Pressure (psi)	Joint Yield Strength		
									Coup. Outside Dia.									
Nom (in.)	OD (in.)	T & C Non-Upset (lb/ft)	T & C Upset (lb/ft)	Int Jt (lb/ft)				Drift Dia. (in.)	Non-Upset (in.)	Upset Reg. (in.)	Upset Spec. (in.)	Drift Dia. (in.)	Box OD (in.)			T & C Non-Upset (lb)	T & C Upset (lb)	Int. Jt. (lb)
3/4	1.050	1.14	1.20		H-40	.113	.824	.730	1.313	1.660				7,680	7,530	6,360	13,300	
	1.050	1.14	1.20		J-55	.113	.824	.730	1.313	1.660				10,560	10,360	8,740	18,290	
	1.050	1.14	1.20		C-75	.113	.824	.730	1.313	1.660				14,410	14,120	11,920	24,940	
	1.050	1.14	1.20		N-80	.113	.824	.730	1.313	1.660				15,370	15,070	12,710	26,610	
1	1.315	1.70	1.80	1.72	H-40	.133	1.049	.955	1.660	1.900		.955	1.550	7,270	7,080	10,960	19,760	15,970
	1.315	1.70	1.80	1.72	J-55	.133	1.049	.955	1.660	1.900		.955	1.550	10,000	9,730	15,060	27,160	21,960
	1.315	1.70	1.80	1.72	C-75	.133	1.049	.955	1.660	1.900		.955	1.550	13,640	13,270	20,540	37,040	29,940
	1.315	1.70	1.80	1.72	N-80	.133	1.049	.955	1.660	1.900		.955	1.550	14,550	14,160	21,910	39,510	31,940
1 1/4	1.660			2.10	H-40	.125	1.410					1.286	1.880	5,570	5,270			22,180
	1.660	2.30	2.40	2.33	H-40	.140	1.380	1.286	2.054	2.200		1.286	1.880	6,180	5,900	15,530	26,740	22,180
	1.660			2.10	J-55	.125	1.410					1.286	1.880	7,660	7,250			30,500
	1.660	2.30	2.40	2.33	J-55	.140	1.380	1.286	2.054	2.200		1.286	1.880	8,500	8,120	21,360	36,770	30,500
	1.660	2.30	2.40	2.33	C-75	.140	1.380	1.286	2.054	2.200		1.286	1.880	11,580	11,070	29,120	50,140	41,600
	1.660	2.30	2.40	2.33	N-80	.140	1.380	1.286	2.054	2.200		1.286	1.880	12,360	11,810	31,060	53,480	44,370
1 1/2	1.900			2.40	H-40	.125	1.650					1.516	2.110	4,920	4,610			26,890
	1.900	2.75	2.90	2.76	H-40	.145	1.610	1.516	2.200	2.500		1.516	2.110	5,640	5,340	19,090	31,980	26,890
	1.900			2.40	J-55	.125	1.650					1.516	2.110	6,640	6,330			36,970
	1.900	2.75	2.90	2.76	J-55	.145	1.610	1.516	2.200	2.500		1.516	2.110	7,750	7,350	26,250	43,970	36,970
	1.900	2.75	2.90	2.76	C-75	.145	1.610	1.516	2.200	2.500		1.516	2.110	10,570	10,020	35,800	59,960	50,420
	1.900	2.75	2.90	2.76	N-80	.145	1.610	1.516	2.200	2.500		1.516	2.110	11,280	10,680	38,180	63,960	53,780
2 1/16	2.063			3.25	H-40	.156	1.751					1.657	2.325	5,590	5,290			35,690
	2.063			3.25	J-55	.156	1.751					1.657	2.325	7,690	7,280			49,070
	2.063			3.25	C-75	.156	1.751					1.657	2.325	10,480	9,920			66,910
	2.063			3.25	N-80	.156	1.751					1.657	2.325	11,180	10,590			71,370
2 3/8	2.375	4.00			H-40	.167	2.041	1.947	2.875					5,230	4,920	30,130		
	2.375	4.60	4.70		H-40	.190	1.995	1.901	2.875	3.063	2.910			5,890	5,600	35,960	52,170	
	2.375	4.00			J-55	.167	2.041	1.947	2.873					7,190	6,770	41,430		
	2.375	4.60	4.70		J-55	.190	1.995	1.901	2.875	3.063	2.910			8,100	7,700	49,450	71,730	
	2.375	4.00			C-75	.167	2.041	1.947	2.875					9,520	9,230	56,500		
	2.375	4.60	4.70		C-75	.190	1.995	1.901	2.875	3.063	2.910			11,040	10,500	67,430	97,820	
	2.375	5.80	5.95		C-75	.254	1.867	1.773	2.875	3.063	2.910			14,330	14,040	96,560	126,940	
	2.375	4.00			N-80	.167	2.041	1.947	2.875					9,980	9,840	60,260		
	2.375	4.60	4.70		N-80	.190	1.995	1.901	2.875	3.063	2.910			11,780	11,200	71,930	104,340	
	2.375	5.80	5.95		N-80	.254	1.867	1.773	2.875	3.063	2.910			15,280	14,970	102,990	135,400	
	2.375	4.60	4.70		P-105	.190	1.995	1.901	2.875	3.063	2.910			15,460	14,700	94,410	136,940	
	2.375	5.80	5.95		P-105	.254	1.867	1.773	2.875	3.063	2.910			20,060	19,650	135,180	177,710	
2 7/8	2.875	6.40	6.50		H-40	.217	2.441	2.347	3.500	3.668	3.460			5,580	5,280	52,780	72,480	
	2.875	6.40	6.50		J-55	.217	2.441	2.347	3.500	3.668	3.460			7,680	7,260	72,580	99,660	
	2.875	6.40	6.50		C-75	.217	2.441	2.347	3.500	3.668	3.460			10,470	9,910	98,970	135,900	
	2.875	8.60	8.70		C-75	.308	2.259	2.165	3.500	3.668	3.460			14,350	14,060	149,360	186,290	
	2.875	6.40	6.50		N-80	.217	2.441	2.347	3.500	3.668	3.460			11,160	10,570	105,570	144,960	
	2.875	8.60	8.70		N-80	.308	2.259	2.165	3.500	3.668	3.460			15,300	15,000	159,310	198,710	
	2.875	6.40	6.50		P-105	.217	2.441	2.347	3.500	3.668	3.460			14,010	13,870	138,560	190,260	
	2.875	8.60	8.70		P-105	.308	2.259	2.165	3.500	3.668	3.460			20,090	19,690	209,100	260,810	
3 1/2	3.500	7.70			H-40	.216	3.068	2.943	4.250					4,630	4,320	65,070		
	3.500	9.20	9.30		H-40	.254	2.992	2.867	4.250	4.500	4.180			5,380	5,080	79,540	103,610	
	3.500	10.20			H-40	.289	2.922	2.797	4.250					6,060	5,780	92,550		
	3.500	7.70			J-55	.216	3.068	2.943	4.250					5,970	5,940	89,470		
	3.500	9.20	9.30		J-55	.254	2.992	2.867	4.250	4.500	4.180			7,400	6,980	109,370	142,460	
	3.500	10.20			J-55	.289	2.922	2.797	4.250					8,330	7,950	127,250		
	3.500	7.70			C-75	.216	3.068	2.943	4.250					7,540	8,100	122,010		
	3.500	9.20	9.30		C-75	.254	2.992	2.867	4.250	4.500	4.180			10,040	9,520	149,140	194,260	
	3.500	10.20			C-75	.289	2.922	2.797	4.250					11,360	10,840	173,530		
	3.500	12.70	12.95		C-75	.375	2.750	2.625	4.250	4.500	4.180			14,350	14,060	230,990	276,120	
	3.500	7.70			N-80	.216	3.068	2.943	4.250					7,870	8,640	130,140		
	3.500	9.20	9.30		N-80	.254	2.992	2.867	4.250	4.500	4.180			10,730	10,160	159,090	207,220	
	3.500	10.20			N-80	.289	2.922	2.797	4.250					12,120	11,560	185,100		
	3.500	12.70	12.95		N-80	.375	2.750	2.625	4.250	4.500	4.180			15,210	15,000	246,990	294,530	
	3.500	9.20	9.30		P-105	.254	2.992	2.867	4.250	4.500	4.180			13,050	12,310	208,900	271,970	
	3.500	12.70	12.95		P-105	.375	2.750	2.625	4.250	4.500	4.180			20,040	19,690	321,990	386,570	
4	4.000	9.50			H-40	.226	3.548	3.423	4.750					4,060	3,960	72,000		
	4.000		11.00		H-40	.262	3.476	3.351		5.000				4,660	4,540		123,070	
	4.000	9.50			J-55	.226	3.548	3.423	4.750					5,110	5,440	99,010		
	4.000		11.00		J-55	.262	3.476	3.351		5.000				6,590	6,400		[illegible]	
	4.000	9.50			C-75	.226	3.548	3.423	4.750					6,750	7,420	[illegible]		
	4.000		11.00		C-75	.262	3.476	3.351		5.000				8,410	8,600		[illegible]	
	4.000	9.50			N-80	.226	3.548	3.423	4.750					6,590	7,910	144,010		
	4.000		11.00		N-80	.262	3.476	3.351		5.000				8,930	9,170		146,140	
4 1/2	4.500	12.60	12.75		H-40	.271	[illegible]	[illegible]	[illegible]	[illegible]				4,500	4,220	[illegible]	[illegible]	
	4.500	12.60	12.75		J-55	.271	[illegible]	[illegible]	[illegible]	[illegible]				[illegible]	[illegible]	[illegible]	[illegible]	
	4.500	12.60	12.75		C-75	.271	[illegible]	[illegible]	[illegible]	[illegible]				[illegible]	[illegible]	[illegible]	[illegible]	
	4.500	[illegible]	[illegible]		N-80	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]				[illegible]	8,430	[illegible]	[illegible]	

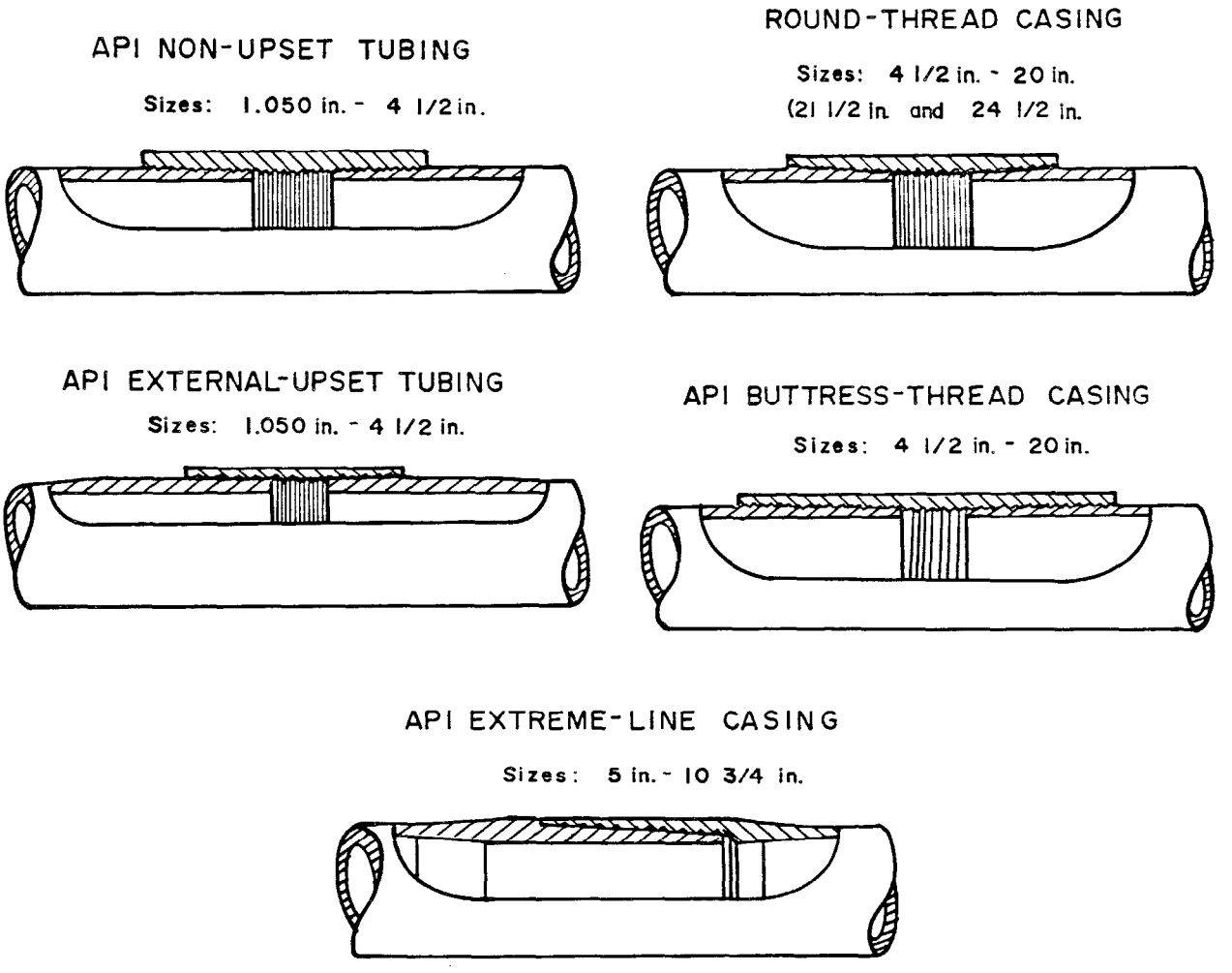


Figure 4.2. Standard API coupling connections for joining steel casing (Halliburton Services, 1981)

The corrosion rate of steel casing is highly dependent upon the environment surrounding the well and the chemical characteristics of the injection fluid. Table 4.5 presents materials well suited for hydrogen-sulfide, carbon-dioxide, and oxygen corrosion environments. Although many of these materials are quite expensive, their use may prove economical, particularly for the bottom-most strings which contact the injection zone directly. In a recent study (McGright, et al., 1980) casing materials in injection wells associated with geothermal applications were investigated to determine their ability to resist corrosion from brine. The study concluded that API Grade J-55 casing was not suitable for long life requirements of the injection zone, but API Grade N-80 and C-75 exhibited a better resistance. API Grade C-75 in particular, with a lower maximum yield strength [90,000 psi (6.2×10^8 N/m^2) vs. 110,000 psi (7.6×10^8 N/m^2) for N-80], could eliminate the susceptability to delayed failure resulting from hydrogen-sulfide cracking or stress-corrosion cracking.

4.1.2 Plastic Casing

Casing is also made of nonmetal materials. Plastics are organic materials with plastizers, inert fillers, and hardners which give improved mechanical and physical properties. Two major groups of plastic casing have been developed which are applicable to injection-well completion, thermoset plastic and thermoplastic. Themoset plastics are permanently "set" once they are shaped and cannot be subsequently reformed by either chemical action or application of heat. Thermoset plastics include epoxy and vinyl-epoxy resins which can be reinforced with fiberglass.

Thermoplastics, on the other hand, can be formed and reformed repeatedly by the application of heat followed by cooling. Thermoplastics include acrylonitrile-butadiene-styrene (ABS), polyvinyl chloride (PVC), chlorinated PVC (CPVC), and styrene rubber (SR). Both thermoset and thermoplastic casing are highly resistant to electrochemical corrosion, but are susceptible to solvation (physical absorption by a plastic or an organic solvent) (NWWA, 1980; Allen and Roberts, 1978).

Although weaker and more sensitive to temperature and pressure influences than metallic casing materials, plastic

TABLE 4.5
SUITABILITY OF CASING AND TUBULAR GOODS
TO VARIOUS CORROSION ENVIRONMENTS
(Allen and Roberts, 1978)

ACCEPTABLE FOR HYDROGEN SULFIDE

1. Low and medium alloy carbon steels, <1 percent nickel, not finished
2. J-55, C-75, N-80, SOO-90
3. 300 series stainless steel Annealed
4. Incoloy 800 (Ni-Cr-Fe)
5. Incoloy 825 (Ni, Fe, Cr, Mo)
6. Inconel 600 (Ni, Cr)
7. Inconel X-750 (Ni-Cr-Al)
8. Monel 400 (Ni-Cu) Annealed
9. K-monel 500 (Ni-Cu-Mo)
10. Hastelloy C (Ni-Cr-Mo)
11. MP35N (Co-Ni, Cr, Mo)
12. Stellites (Co-Cr-W)
13. Colomonoys (Ni-Cr-B)
14. Cemented carbides (Tungsten Carbide)

UNACCEPTABLE FOR HYDROGEN SULFIDE

1. Low and medium alloy steels, >1 percent nickel or cold finished
2. Free machining steels, >0.08 percent sulfur
3. Stainless steel, cold finished or precipitation hardened
4. K-monel, cold finished

ACCEPTABLE FOR CARBON DIOXIDE

1. Stainless steels, except free mechining
2. Monels (Ni-Cu)
3. Nickel-iron (Ni-resist)
4. Al-bronze (Cu-Al)

ACCEPTABLE FOR OXYGEN

1. Stainless steels
2. Monels
3. Nickel-iron
4. Al-bronze

casing is extremely well suited for the injection of highly corrosive fluids. The most commonly used thermoset casing consists of epoxy-resin fiberglass-reinforced material. Based on temperature resistance and strength, epoxy resins are superior to other types of resins (Allen and Roberts 1978). Tables 4.6 and 4.7 include the specifications and physical properties for one brand of commercially available thermoset casing. Maximum pressures and temperatures for epoxy resin-fiberglass reinforced casing are approximately 300 psi (2.1×10^6 N/m^2) and 150°F (65.5°C), respectively. Joint make-up for epoxy resin is similar to the coupling and connection techniques used for steel. Epoxy resin has been replacing the use of thermoplastic casing such as PVC, because of improved strength and higher temperature rating (Allen and Roberts, 1978). (The API has tentatively established specifications for reinforced thermosetting resin casing and tubing under API Spec 5AR, 1975.)

Table 4.8 describes typical physical properties of thermoplastic materials. Maximum operating temperatures for ABS, PVC, and SR casing are approximately 100°F (37.7°C). Thermoplastic casing of similar wall thickness and diameter as thermoset casing is generally weaker. However, compared to steel, thermoplastic casing has a greater resiliency, flexibility, and abrasion resistance. Joint make-up for thermoplastic casing can be formed through either traditional threaded and coupled connections or by solvent cementing.

Perhaps the single most important factor limiting the use of thermoplastic casing in completion of injection wells is sensitivity to temperature. For example, the heat of hydration of some cements used for completing the injection well could increase the surrounding temperature enough to cause a solvent cement joint to fail, or could reduce the strength of the casing. As a result, the use of concentrated quick-drying cement is not recommended for use in wells cased with thermoplastic materials (NWWA, 1980). However, within given operating temperatures, the strength and durability of thermoplastic casing has permitted its use in water-well completions to depths of over 2000 feet (610 m) (American Society for Testing and Materials, 1977).

With respect to corrosion resistance, thermoset and thermoplastic materials are uniquely superior to metallic materials. Since plastics are nonconductors, they are not

TABLE 4.6
OPERATING CONDITIONS OF FIBERGLASS CASING
(Koch Fiberglass Products Co., 1981)

	TBS-210		TBS-810		TBS-1010	
	3 in.	4 in.	3 in.	4 in.	3 in.	4 in.
SPECIFICATIONS:						
Wt-lbs/ft	.88	.95	1.40	1.80	1.90	2.95
O.D., inches	3.50	4.50	3.65	4.70	3.76	4.86
I.D., inches	3.36	4.36	3.36	4.36	3.36	4.36
Wall, inches	.08	.10	.15	.175	.20	.25
Upset O.D.	3.80	4.90	4.225	5.225	4.376	5.65
OPERATING CONDITIONS:						
Pressure, psi	300	300	800	800	1,000	1,000
Collapse, psi	100	75	500	250	1,000	1,000
Temperature, °F	150	150	150	150	150	150
Tensile pounds across joint	11,000	15,000	18,000	19,000	-	-
Pipe body, psi	11,700	16,000	20,000	26,000	-	-

TABLE 4.7
OPERATING CONDITIONS AND PHYSICAL PROPERTIES
OF FIBERGLASS TUBING
(Koch Fiberglass Products Co., 1981)

	K-1250, Gray				K-2000, Black			
	2-3/8 in.	2-7/8 in.	3-1/2 in.	4-1/2 in.	2-3/8 in.	2-7/8 in.	3-1/2 in.	4-1/2 in.
SPECIFICATIONS:								
Wt-lbs/ft	1.20	1.40	2.40	3.05	1.40	1.70	3.00	3.73
O.D., in.	2.39	2.85	3.50	4.58	2.50	2.93	3.73	4.70
I.D., in.	2.00	2.43	3.00	4.00	2.00	2.43	3.00	4.00
Wall, in.	0.19	0.21	0.25	0.29	0.25	0.27	0.31	0.35
Upset O.D., in.	3.25	3.75	4.75	5.25	3.25	3.83	4.88	5.75
OPERATING CONDITIONS AT 150°F:								
Pressure, psig	1,500	1,500	1,500	1,500	2,000	2,000	2,000	2,000
Collapse, psig	1,250	1,100	1,000	1,000	2,000	1,750	1,500	1,500
Tensile pounds	9,000	10,500	11,000	12,000	10,000	12,500	15,000	12,000
Temperature, °F	150	150	150	150	150	150	150	150
Pressure, psig	1,875	1,875	1,875	-	3,000	3,000	3,000	-
Mill test, mill test tensile, lbs	9,000	10,500	11,000	-	10,000	12,500	15,000	-
PHYSICAL PROPERTIES:								
Ultimate failure, internal, psig	3,800*	4,050	3,600	-	6,000	4,600	4,500	-
short term, psig	3,800**	4,200	3,900	-	4,200	5,000	4,600	-
Ultimate collapse	4,500*	3,200	4,400	-	9,400	9,600	10,200	-
pressure, psig	4,500**	3,100	4,200	-	9,100	9,250	9,500	-
Ultimate tensile	43,000*	55,550	78,000	-	50,000	57,750	79,000	-
across joint, lbs	36,000**	48,750	70,000	-	39,000	48,000	75,000	-
Modulus of elasticity in tension	3.4×10^4				3.5×10^6			
Linear coefficient of thermal expansion In./1000 ft/°F	0.09				0.09			
Specific gravity	1.90				1.90			
Flow factor, Hazen Williams	150				150			

TABLE 4.8
TYPICAL PHYSICAL PROPERTIES OF THERMOPLASTIC
WELL CASING MATERIALS AT 73.4°F
(NWWA, 1980)

Property	ASTM Test Method	ABS Cell Class, per D-1788		PVC Cell Class, per D-1784		SRR Cell Class, per D-18922
		434	533	12454-B&C	14333-C&D	4434AA
Specific gravity	D-792	1.05	1.04	1.40	1.35	1.05
Tensile strength, psi	D-638	6,000*	5,000*	7,000*	6,000*	3,100*
Tensile modulus of elasticity, psi	D-638	350,000	250,000	400,000*	320,000*	320,000
Compressive strength, psi	D-695	7,200	4,500	9,000	8,000	5,000
Impact strength, Izod, ft-lb/inch notch	D-256	4.0*	6.0*	0.65	5.0	0.9
Deflection temperature under load (264 psi), °F	D-648	190*	190*	158*	140*	180
Coefficient of linear expansion, in/in-°F	D-696	5.5×10^{-5}	6.0×10^{-5}	3.0×10^{-5}	5.0×10^{-5}	4.8×10^{-5}

* These are minimum values set by the corresponding ASTM Cell Class designation. All others represent typical values.

susceptible to corrosion by galvanic and electrochemical effects. They are also resistant to chemical attack by oil and water and are unaffected by microbial agents. Plastic casing has been used for such applications as injection of waste pickle liquors (Bayazeed and Donaldson, 1973) and for injection of acids in uranium leaching mines (Koch Fiberglass Products Company, 1981). However, such materials may be susceptible to organic solvents such as acetone, methyl ethyl ketone, toluene, trichloroethylene, turpentine, and xylene (NWWA, 1980; Allen and Roberts, 1978). Plastics can also be used for liners for metallic casing to protect against corrosion.

4.2 CEMENT

Well-construction service companies indicate that the single most important factor in insuring well integrity is obtaining a satisfactory primary-cementing job. Primary cementing involves the placement of cement in the annulus between the borehole and the outermost casing and/or the concentric strings of casing, to restrict fluid movement between formations as well as to support and to bond the casing (Warner and Lehr, 1977). In addition, the low permeability of cement protects the casing from corrosive salt-water zones and microbial agents and isolates high pressure or lost-circulation zones.

4.2.1 General Manufacture, Composition, and Characteristics of Completion Cement

The most common cement used in well completion is Portland cement. Portland cement is manufactured by calcining raw materials consisting of limestone, clay, and shale (or other materials high in calcium chloride) in a rotary kiln at temperatures between 2600°F to 2800°F (1427°C to 1538°C) (Moore, 1974). The resulting material (clinker) is finely ground with a controlled amount of gypsum (1.5 to 3 percent by weight) to form the finished cement. In addition to the raw materials, other substances such as sand, bauxite, or iron oxides may be added to adjust the chemical composition of the clinker and to achieve specific types of Portland cement.

Cement contains four compounds that aid in the formation of a rigid structure (hydration). Generically, the compounds contain lime, silica, alumina, and iron expressed as:

1. Tricalcium silicate (C_3S) is the major compound found in most Portland cement and is the principal strength producing material. It is responsible for early strength development ranging from 1 to 28 days.

2. Dicalcium silicate (C_2S) is a slow-hydration compound and accounts for the gradual gain in strength which occurs over an extended period of time.

3. Tricalcium aluminate (C_3A) promotes rapid hydration and controls the initial set and thickening time of the cement slurry. It increases the susceptibility of cement to sulfate attack; high sulfate-resistant cement must have 3 percent or less C_3A.

4. Tetracalcium aluminoferite (C_4AF) is a low heat-of-hydration compound. High concentrations of C_4AF tend to promote strength retrogression. An excess of iron oxide will increase the amount of C_4AF and decrease the amount of C_3A in the cement.

Table 4.9 presents typical compositions of various classes of cements according to the relative concentration of the four compounds (Moore, 1974). In addition, the table shows the fineness of the grind of each class of cement and lists cement properties that may be desired and the associated controlling factors.

Table 4.10 provides specifications for the API oil-well cement classes in terms of mixing-water requirements, cement-slurry weight, well depth, and static temperature. In addition, sulfate resistance, susceptibility to extreme temperatures and pressures, and compatibility with cement additives are identified for several classes of cement.

Two important criteria in selecting a cement are compressive strength development and thickening time (pumpability time) (see Tables 4.11 and 4.12). Both of these criteria are primary factors determining the waiting on

TABLE 4.9
TYPICAL COMPOSITION OF PORTLAND CEMENT
(Moore, 1974)

API Class	Compounds (percent)				Wagner Fineness (Sq.Cm./Gram)
	C_3S	C_2S	C_3A	C_4AF	
A	53	24	>8	8	1600 - 1800
B	47	32	<5	12	1600 - 1800
C	58	16	8	8	1800 - 2200
D & E	26	54	2	12	1200 - 1500
G & H	50	30	5	12	1600 - 1800

Property:	How Achieved:
High early strength	Increasing the C_3S content, finer grinding
Better retardation	Control C_3S, C_3A contents and grind coarser
Low heat of hydration	Limiting the C_3S and C_3A content
Resistance to sulfate attack	Limiting the C_3A content

TABLE 4.10
API CEMENT CLASSIFICATION
(API Spec 10A, 1979)

API Class	Mixing water gal/sack	Slurry weight lb/gal	Well depth ft	Static temperature °F
A	5.2	15.6	0- 6,000	80-170
B	5.2	15.6	0- 6,000	80-170
C	6.3	14.8	0- 6,000	80-170
D	4.3	16.3	6-12,000	170-260
E	4.3	16.3	6-14,000	170-290
F	4.3	16.3	10-16,000	230-320
G	5.0	15.8	0- 8,000	80-200
H	4.3	16.3	0- 8,000	80-200

Class A: Intended for use when special properties are not required. Available only in ordinary type (Type I).
Class B: Intended for use when conditions require moderate to high sulfate-resistance. Available in both moderate (Type II) and high sulfate-resistant types.
Class C: Intended for use when conditions require high early strength. Available in ordinary and moderate (Type III) and high sulfate-resistant types.
Class D: Intended for use under conditions of moderately high temperatures and pressures. Available in both moderate and high sulfate-resistant types.
Class E: Intended for use under conditions of high temperatures and pressures. Available in both moderate and high sulfate-resistant types.
Class F: Intended for use under conditions of extremely high temperatures and pressures. Available in both moderate and high sulfate-resistant types.
Class G: Intended for use as a basic cement as manufactured, or can be used with accelerators and retarders to cover a wide range of well depths and temperatures. Available in moderate and high sulfate-resistant types.
Class H: Intended for use as a basic cement and can be used with accelerators and retarders to cover a wide range of well depths and temperatures. Available in moderate and high sulfate-resistant types.

TABLE 4.11
TYPICAL COMPRESSIVE STRENGTH
OF CEMENT (psi at 24 hr)
(Allen and Roberts, 1978)

Curing Conditions		Class				
Temperature (°F)	Pressure (psi)	A	C	D	G	H
60	0	615	780	*	440	325
80	0	1,470	1,870	*	1,185	1,065
95	800	2,085	2,015	*	2,540	2,110
110	1,600	2,925	2,705	*	2,915	2,525
140	3,000	5,050	3,560	3,045	4,200	3,160
170	3,000	5,920	3,710	4,150	4,830	4,485

* Not recommended at this temperature

TABLE 4.12
HIGH-PRESSURE THICKENING TIME
OF CEMENT
(Allen and Roberts, 1978)

Circulating Temperature (°F)	Class				
	A	C	D	G	H
91	>4:00	>4:00	-	>3:00	3:57
103	3:36	3:10	>4:00	2:30	3:20
113	2:25	2:06	>4:00	2:10	1:57
125	1:40	1:37	>4:00	1:44	1:40

cement (WOC) time, which is the time required to permit the cement to attain sufficient strength to anchor the casing and withstand stresses of subsequent drilling and operation, and to seal permeable zones and confine fracture pressures (Allen and Roberts, 1978). These, as well as other required properties and characteristics of cements, can be obtained through blending specialty cements or by the addition of specific cement additives.

4.2.2 Specialty Cements and Cement Additives

Required properties of the cement to obtain a solid primary-cementing job and to insure the structural integrity of the injection well are shown in Table 4.13. However, such properties are not inherent in all cements to the degree required by specific applications to different environments. For example, high temperatures experienced during primary cementing can cause the cement to set prematurely and inhibit complete placement of the cement. Therefore, several specialty cements and cement additives have been developed to achieve certain properties or alter basic characteristics of standard cement classes. Although sold under numerous trade names, specialty cements basically include: pozzolan slurries, lightweight cements, thixotropic cement, oil-based cement, expanding cement, and calcium aluminate (refractory) cement. (These specialty cements are described along with applications, advantages, and limitations of each type in Table 4.14.)

In general, the creation of new cements or tailoring of standard classes of cement to meet new technology requirements is virtually unlimited, a result of the numerous additives that have been developed. The major cement additive classifications include, accelerators, retarders, density adjusters, lost-circulation materials, filtration (fluid loss) control, and dispersants. A summary of cement additives and additional specialty cements is shown in Table 4.15. (The summary is presented to provide an overview of basic cement additives and does not represent a detailed listing of the numerous additives that have been manufactured.) Several brands of such additives have been developed individually by cementing service industries (see Table 4.16).

TABLE 4.13
CEMENT PROPERTIES AND CHARACTERISTICS
(Allen and Roberts, 1978; Parker, et al, 1977)

Property/Characteristics	Description	Importance
Slurry viscosity	A measure of the thickness of the slurry expressed in units of consistency; cement is a non-Newtonian fluid; viscosity is a function of shear rate.	Viscosities should be kept low for turbulent flow and thus enhance drilling fluid removal. High viscosity enables plug flow cementing.
Thickening time	Time that the cement remains pumpable in the well.	Should be long enough to be pumped into place and short enough to permit operations to resume quickly; normally 2.5 to 3 hours.
Water ratio	Ratio of the weight of water used to the weight of cement; determined by minimum to permit pumpability but avoid solids separation.	Set volume of cement should be equal to slurry volume; free water should be less than 1 percent.
Mixing water	Water mixed with cement to produce slurry.	Fresh water is preferable to avoid unwanted acceleration or retardation of cement due to inorganic or organic compounds, respectively.

TABLE 4.13 (Cont'd)

Property/Characteristics	Description	Importance
Strength Development	Compressive strength of the set cement measured in psi. Pressure and temperature affect the rate of strength development. Compressive strength increases as density increases.	Required to support the casing and seal permeable zones and confine fracture pressures; usually compressive strength of 500 psi is required before drilling operations can proceed.
Density	Weight per volume (lb/gal) of the cement slurry; density should be low enough to be supported by weak formations and heavy enough to control well pressures; the density of the cement should be greater than drilling fluids to ensure adequate displacement.	Affects other properties such as thickening time, compressive strength and permeability.
Fluid loss	The loss of water from the slurry to the formation during cement placement; measured as a rate.	Control of fluid loss is important in order to avoid density and viscosity increases which can inhibit pumpability, block off cement flow, or stick casing; fluid loss control is a particular concern where gas communication is likely.

TABLE 4.13 (Cont'd)

Property/Characteristics	Description	Importance
Permeability	The measure of the ease with which a fluid flows through the connecting pore spaces of rock or cement.	The lower the permeability of the cement the greater the compressive strength and protection of the casing to corrosive formation fluids.
Sulfate resistance	Ability of a cement to resist deterioration in the presence of sulfate ions; sulfite resistance is controlled by concentration of tricalcium aluminate (C_3A): . 3 percent C_3A high sulfate resistance . 8 percent C_3A moderate sulfate resistance.	Sulfate reacts with C_3A to form sulfo-aluminates which upon enlargement develop cracks, in the cement, increasing permeability and decreasing strength.
Heat of Hydration	Heat generated by the chemical reactions of the setting cement; heat developed by cement setting in a 2-inch annulus will increase temperature 30° to 40°F.	Of particular concern in permafrost regime; increased temperature can melt ice lenses and prevent bonding.

TABLE 4.13 (Cont'd)

Property/Characteristics	Description	Importance
Bonding	The state of bond between cement and casing and/or formation; bonding is enhanced by cement expansion; bond strength is estimated with shear-bond and hydraulic-bond tests.	Mechanically supports casing in wellbore and blocks migration of fluids; bond strength increases with compressive and tensile strength.

TABLE 4.14
APPLICATIONS, ADVANTAGES AND LIMITATIONS OF SELECTED SPECIALTY CEMENTS
(Parker, et al., 1977)

Cement	Slurry weight (lb/gal)	Composition	Application	Advantages	Limitations
Pozzolan	13-15	Blend of Class A or H with Pozzolan - either natural diatomaceous earth (Diacel A) or manmade fly ash, properties can be further modified with bentonite or lime.	Used primarily for casing cementing, but also used for squeeze cementing and lost circulation plugs.	Wide range of water rations. Predictable thickening time and compressive strength. Can be used at all depths and temperatures. Highly sulfate resistant. Resist strength retrogression at high temperatures. Compatible with all additives. Very economical.	Compressive strengths are lower than Portland cements.
Light Weight	12-14	Blend of portland cement and calcined shale.	Used both as a filler and completion cement, and in weak formations which could not withstand hydrostatic pressure of normal-weight portland cement.	Wide range of predictable retardation densities. Economical filler slurries. Densified slurries achieve adequate compressive strength. Sulfate resistant with low permeability.	
Thixotropic	11-15	Blends of portland cement and sulfate hemihydrate; and most important is ability to form a gel structure upon cessation of movement.	Designed for cementing lost-circulation zones, vuggy or fractured formations and difficult squeeze cementing. Other applications: Cement casing to eliminate staging. Seal off permeable zones. Reduce gas cutting.	May be used to 240°F bottom hole circulating temperatures. Self-supporting - eliminates fallback or need for "topping out." Reduces gas cutting. Early compressive strength. Pumpable as long as water is not contacted.	Gel cannot be broken after 15 minutes. Cannot be mixed with salt or conventional retarders. High fluid loss.
Oil-Based	(Uses no water)	Blend of liquid hydrocarbon (Diesel), surfactants, and either Class A or H Cement, water is obtained from zone being cemented.	Used to shut off water encroachment, leaking casing or lost circulation zones.	Forms a viscous slurry upon contact with water. High early compressive strength. Pumpable as long as water is not contacted.	Limited availability of diesel or kerosine. Difficult to keep system water-free. Setting may be difficult to control. Flammable.
Expanding	14.0	Blend of portland cement and calcium sulfoaluminate, which expands upon setting.	Used to improve bonding between cement and casing and/or formation, also used for squeeze cementing to seal perforations or holes in casing.	Expands upon setting and and rapidly after setting. Improves bonding.	Limited to below 200°F Deterimentally affected by conventional retarders. Not recommended for use with salt.
Calcium Aluminate (Refractory)		Portland cement blended with limestone and bauxite. Additives include 40 percent silica flour to improve strength retrogression.	Used for cementing wells in both cold and high temperature environments; well suited for geothermal or fire flood wells.	Resists strength retrogression up to 700°F with silica flour or firebrick. Rapid compressive strenght development. Resists corrosive water.	Requires larger retarder concentrations above 200°F. Expensive.

TABLE 4.15
SUMMARY OF CEMENT ADDITIVES
(Shyrock and Smith, 1981)

Type of Additive	Use	Chemical Composition	Benefit	Type of Cement
Accelerators	Reducing WOC time. Setting surface pipe. Setting cement plugs. Combating lost circulation.	Calcium chloride Sodium chloride Gypsum Sodium silicate Dispersants Sea water	Accelerated setting. High early strength.	All API Classes Pozzolans Diacel systems
Retarders	Increasing thickening time for placement. Reducing slurry viscosity.	Lignosulfonates Organic acids CMHEC Modified lignosulfonates	Increased pumping time. Better flow properties.	API Classes D, E, G, & H Pozzolans Diacel systems
Weight-reducing additives	Reducing weight. Combating lost circulation.	Bentonite-attapulgite Gilsonite Diatomaceous earth Perlite Pozzolans	Lighter weight. Economy. Better fillup. Lower density.	All API Classes Pozzolans Diacel systems
Heavy-weight additives	Combating high pressure. Increasing slurry weight.	Hematite Ilmenite Barite Sand Dispersants	Higher density.	API Classes D, E, G, & H
Controlling lost circulation	Bridging. Increasing fillup. Combating lost circulation.	Gilsonite Walnut hulls Cellophane flakes Gypsum cement Bentonite-diesel oil Nylon fibers	Bridged fractures. Lighter fluid columns. Squeezed fractured zones. Minimized lost circulation.	All API Classes Pozzolans Diacel systems
Filtration control	Squeeze cementing. Setting long liners. Cementing in water-sensitive formations.	Polymers Dispersants CMHEC Latex	Reduced dehydration. Lower volume of cement. Better fillup.	All API Classes Pozzolans Diacel systems
Dispersants	Reducing hydraulic horsepower. Densifying cement slurries for plugging. Improving flow properties.	Organic acids Polymers Sodium chloride Lignosulfonates	Thinner slurries. Decreased fluid loss. Better mud removal. Better placement.	All API Classes Pozzolans Diacel systems
Special cements or additives				
Salt	Primary cementing.	Sodium chloride	Better bonding to salt, shales, sands.	All API Classes
Silica flour	High-temperature cementing.	Silicon dioxide	Stabilized strength. Lower permeability.	All API Classes
Mud Kil inhibitor	Neutralizing mud-treating chemicals.	Paraformaldehyde	Better bonding. Greater strength.	API Classes A, B, C, G, & H
Radioactive tracers	Tracing flow patterns. Locating leaks.	Sc 46		All API Classes
Pozzolan lime	High-temperature cementing.	Silica-lime reactions.	Lighter weight. Economy.	
Silica lime	High-temperature cementing.	Silica-lime reactions.	Lighter weight.	
Gypsum cement	Dealing with special conditions.	Calcium sulfate Hemihydrate	Higher strength. Faster setting.	
Hydromite	Dealing with special conditions.	Gypsum with resin	Higher strength. Faster setting.	
Latex cement	Dealing with special conditions.	Liquid or powdered latex.	Better bonding Controlled filtration	API Classes A, B, C, G, & H

TABLE 4.16
BRAND NAMES OF CEMENT ADDITIVES
(Allen and Roberts, 1978)

Product Classification	Product Trade Names				
	Halliburton	Dowell	B.J.	Western	Chemical or Material Description
Accelerators	$CaCl_2$	S-1	A-7	$CaCl_2$	Calcium chloride
	HA-5	D-43	A-8	WA-4	Blend of inorganic accelators
	D-12	A-2	Diacel A	Diacel A	Diacel A
	Salt	Salt	A-5	Salt	Sodium chloride, granulated
H-TLW blends	1:1(etc)	1:1(etc)	-	1:1 Talc	-
Fluid Loss	Halad 9, 11, 14	D-60	Aquatrol 13, 15	CF-1	Low temp. fluid loss control
	-	D-59	-	CF-2	Low temp. fluid loss control
	Diacel LWL	D-8	R-6	Diacel LWL	Carboxymethyl Hydroxyethyl
Liquid Turbulence Inducers	-	D-73	-	-	Cellulose
	CFR-2	D-65,45	Turbo-Mix D-16	TF-4	Polymer
	CFR-1	-	Turbo-Mix D-30	TF-5	-
Weighting Material	Barite	D-31	W-1	Barite	Barite
	Hi Dense 3	D-76	-	WM-2	Hematite
	Hi Dense 2	D-18	W-3	Hmenite	Hmenite
Spacers and Washes	Mud-flush	CW-7	Mud-sweep	WMW-1	Mud thinner-spacer
	Sam 4	Oil-base mud spacer	J-22 and D-4	ASP-4	Oil-base spacer
	-	-	-	ASP-4	Water-base spacer
Latex Extenders	LA-2	D-15, D-78	D-5	CLX-1	Latex cement
	Howco Gel	Bentonite	B.J. Gel	Bentoment	Bentonite
	Gilsonite	Kolite	D-7	Gilsonite	Gilsonite
	Econolite	-	Lo-Dense	Thrifty-Lite	Anhydrous sodium metasilicate
	Pozmix A	Litepoz 3	Diamix A, G, M	Pozment A	Artificial pozzolans
	-	Litepoz 1	Diamix A, M, G	Pozment N	Natural Pozzolans
	Pozmix 140	Litepoz 180	Thermoset	-	Pozzolan-lime mixtures
	Howcolight HLC	D-79	Lo dense	Thrifty-ment	H-poz blends
Anti-Foam	NF-P	D-46	D-6	AF-4	Powdered anti-foam agent
	NF-1	D-47	D-6	AF-L	Liquid anti-foam agent
Mud Decontaminant	Mud Kil-1	K-21	Firm set I	Shur set I	Mud kill patented by Gulf Oil
	Mud Kil-2	K-21	Firm set II	Shur set II	Mud kill patented by Gulf Oil
Silica Sand	Silica flour (reg.)	J-84	D-8	SF-3	325 Mesh silica flour
	Silica flour (coarse)	D-30	-	SF-4	Okla. #1 sand
Thixotropic Cement	Thixotropic cement	Reg. fill-up cement	-	Thixoment	Thixotropic slurries
Lost Circulation	Gilsonite	Kolite D2Y	D-7 Gilsonite	Gilsonite	-
	Cellophane flakes	D-29 jel flakes	Cello-Flake	Cell-O-Seal	-
	-	-	-	Kwik-Seal	-
Retarders	Kembreak	Kembreak	Kembreak	WR-1	Low temp. retarder
	HR-4	D-22	Retroset 2	WR-2	Low temp. retarder (calcium lignosulfonate)
	HR-7	D-13	Retroset 5	WR-4	Low temp. retarder
	HR-12	D-28	Retroset 8	WR-6	High temp. organic retarder
	Diacel LWL	D-8	Retroset 6	Diacel LWL	Diacel LWL carboxymethyl Hydroxethyl cellulose
	HR-20	D-99	R10, R11	-	High temp. retarder
	-	D-93	-	WR-7	Borax

4.3 ANCILLARY EQUIPMENT AND MATERIALS

During construction of the well, casing installation and primary cementing are facilitated by the use of ancillary equipment and materials which include centralizers and scratchers, float shoes and collars, plugs and cement baskets, and displacement fluids and washes/spacers. Additionally, annulus fluids surrounding the injection tubing may be required to control injection-fluid placement, to protect against corrosion, and to monitor injection pressure to detect tubing leakage. The following section will highlight such materials indicating their relative importance and their function in well-construction technology. (Not included with this discussion are other equipment and materials such as packers, valves and fittings, screens, and drilling fluids which are described in Chapters 3 and 5.)

Most ancillary equipment is utilized to obtain satisfactory primary cementing. Table 4.17 provides a summary of equipment that can be used in cementing the casing in the borehole. However, not all of the equipment shown in Table 4.17 is utilized in constructing every well, as some of the equipment has very specific applications.

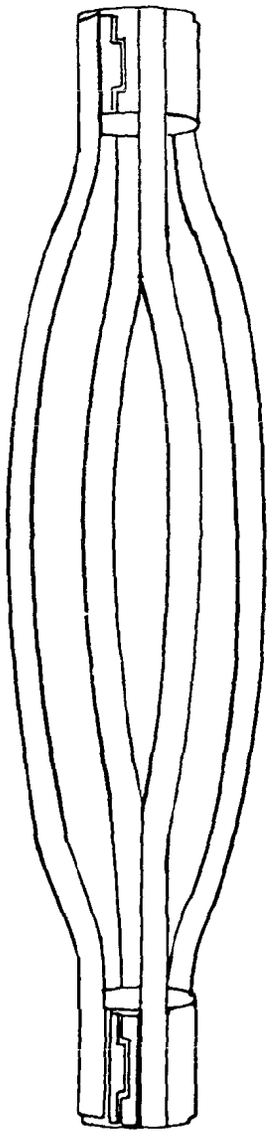
Mechanical devices attached to the outside of the casing enable the casing to be centered in the hole, and thereby facilitate equal distribution of cement surrounding the casing. These devices, referred to as centralizers, (Figure 4.3) are particularly useful for long strings of pipe or for running casing into deviated holes. Some centralizers have built in flanges that cause increased turbulent flow of the cement, which enhances wall cake removal.

Scratchers and wall cleaners may also be attached to the outside of the casing to help remove wall cake and help prepare the formation for bonding with the cement. There are basically two types, reciprocating and rotating, which consist of a steel collar and either bristles or wire loops. Scratchers also reinforce the cement sheath (Figure 4.4).

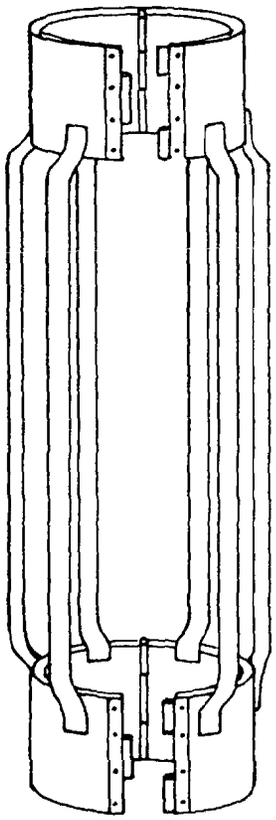
Several different types of floating guide shoes, collars, and plain open end guide shoes are available. Plain open end guide shoes are used to guide the casing past

TABLE 4.17
CEMENT EQUIPMENT AND MECHANICAL AIDS
(Shyrock and Smith, 1981)

Cementing Equipment and Types	Application	Placement
FLOATING EQUIPMENT 1. Guide Shoes	Guides casing into well. Minimizes derrick strain.	First joint of casing
2. Float Collars	Prevents cement flow back. Create pressure differentials to improve bond. Catches cementing plugs.	1 joint above shoe in wells less than 6,000 ft; 2 to 3 joints above shoe in wells greater than 6,000 ft.
AUTOMATIC FILL-UP EQUIPMENT 1. Float Shoes	Same as Float Collars and Guide Shoes except fill-up is controlled by hydrostatic pressure in annulus.	Same as Float Collars or Guide Shoes.
FORMATION PACKER TOOLS 1. Formation Packer Shoes	Packer expands to protect lower zones while cementing.	First joint of casing
2. Formation Packer Collars	-	As hole requirements dictate.
CEMENTING STAGE TOOLS 1. 2-Stage 2. 3-Stage 3. Full Opening Tools	When required to cement two or more sections in separate stages.	Based on critical zones and formation fracture gradients.
PLUG CONTAINERS 1. Quick Opening 2. Continuous Cementing Heads	To hold cementing plugs in string until released.	Top joint of casing at surface of well.
CEMENTING PLUGS 1. Top and Bottom Wiper Plugs 2. Ball Plugs 3. Latch Down Plugs	Mechanical spacer between drilling fluid and cement (bottom plug) and cement and displacement fluid (top plug).	Between well fluids and cement.
CASING CENTRALIZERS 1. Variable Types	Center casing in hole or provide minimum stand-off to improve distribution of cement in annulus, prevent differential sticking.	1 per 1 to 3 joints.
SCRATCHERS OR WALL CLEANERS 1. Rotating	Remove wall cake and circulatable drilling fluid from borehole.	Place through producing formations and 50 to 100 ft above. Rotate pipe 15 to 20 RPM.
2. Reciprocating	Aid in creating turbulence. Improve cement bond.	Placement is same as rotating Reciprocate pipe 10 to 15 ft off bottom.
BRIDGE PLUGS 1. Wire Line 2. Tubing	For permanent or temporary plugging in open hole.	May be placed in well on wire line on tubing or below retrievalbe squeeze packers.
CEMENTING BASKETS AND EXTERNAL PACKERS	For casing or liner where mechanical support is necessary until the cement column sets.	Below stage tools or where weak formations occur downhole.

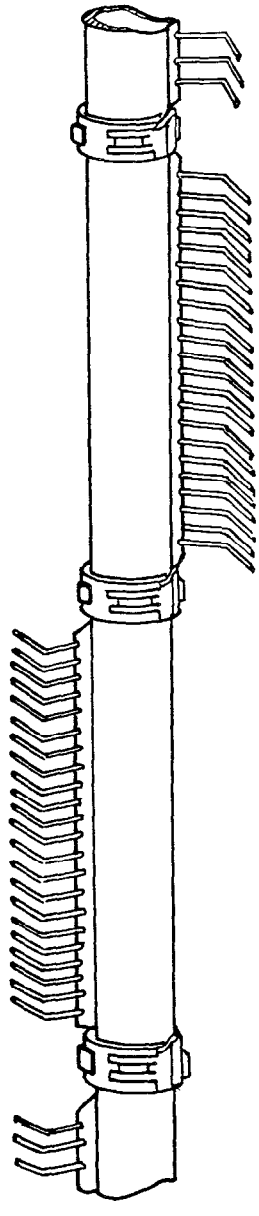


EUE TUBING CENTRALIZER

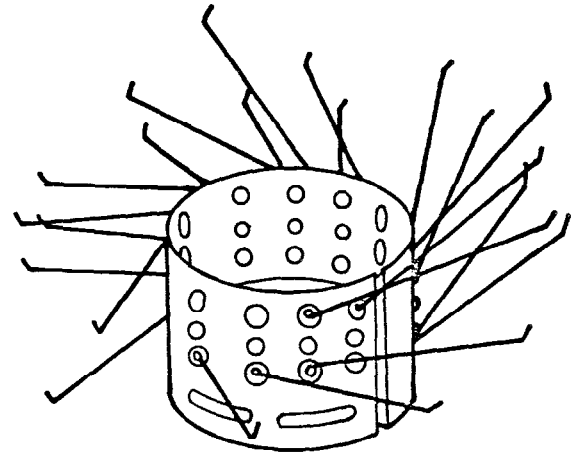


SLIM HOLE TYPE

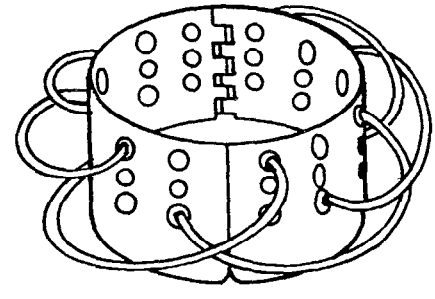
Figure 4.3. Casing centralizers (Halliburton Services, 1981)



ROTO WALL CLEANER



RWC WALL CLEANER



CABLE TYPE WALL CLEANER

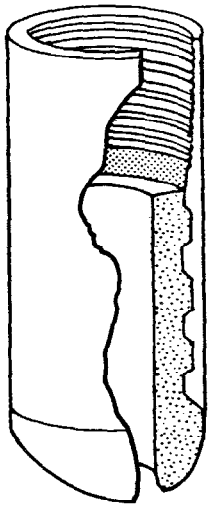
Figure 4.4. Scratchers and wall cleaners (Halliburton, 1981)

any obstruction in the hole. Float guide shoes and float collars serve as a means of floating the casing into the hole and as a back-pressure valve to help prevent any back-flow of cement after it has been placed. Other such equipment, including automatic fill-up float shoes or formation packer shoes, may be used. Formation packers may be particularly useful in completions where low pressure formations must be protected against cement contamination (Figure 4.5).

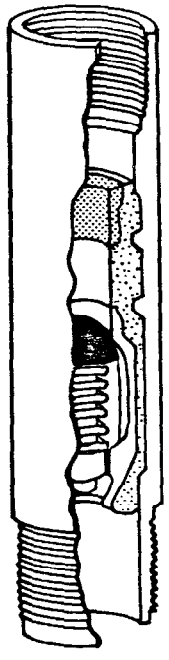
Cementing plugs which are usually made of rubber and aluminum may be used. Top and bottom plugs are used in order to separate the cement from the drilling and displacement fluids. The bottom plug precedes the cement down the casing and wipes drilling fluid from the casing walls. Upon seating on the shoe or collar, the center of the plug ruptures permitting cement to flow through. The top plug is released after all the cement is in the casing ahead of the displacement fluid. The top plug provides a pressure tight seal upon seating with the bottom plug (Figure 4.6).

Various fluids can also be used to achieve efficient drilling-fluid removal and cement placement. The fluids basically consist of spacers and washes, and displacement fluids. Spacers and washes enhance drilling-fluid removal and improve cement bonding. These fluids are usually mixtures of water and surfactants and perhaps scouring agents such as barite, placed in the casing ahead of the cement slurry (Western Co., 1981).

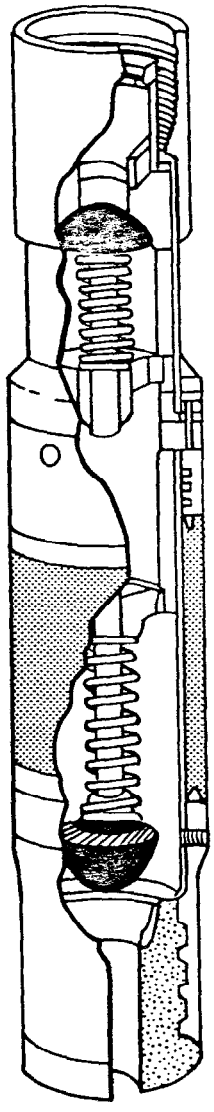
Displacement fluids are put behind the top plug and exert pressure to cause the cement slurry to displace through the casing and up the annulus between the casing and the borehole. For surface and intermediate casing strings, drilling fluid is normally used as the displacement fluid. Depending upon the completion program, freshwater or salt water is used for cementing the injection casing. Either a sugar water or other retarding additive is sometimes placed immediately above the top plug in small diameter casing to inhibit setting of cement that may have bypassed the top plug (Allen and Roberts, 1978). Other equipment used to complete primary cementing includes stage tools, cementing heads, plug containers, cement baskets, and jet mixers (Moore, 1974).



GUIDE SHOE



SUPER SEAL FLOAT COLLAR



FORMATION PACKER SHOE

Figure 4.5. Guide shoes, float collars and packer shoes (Halliburton, 1981)

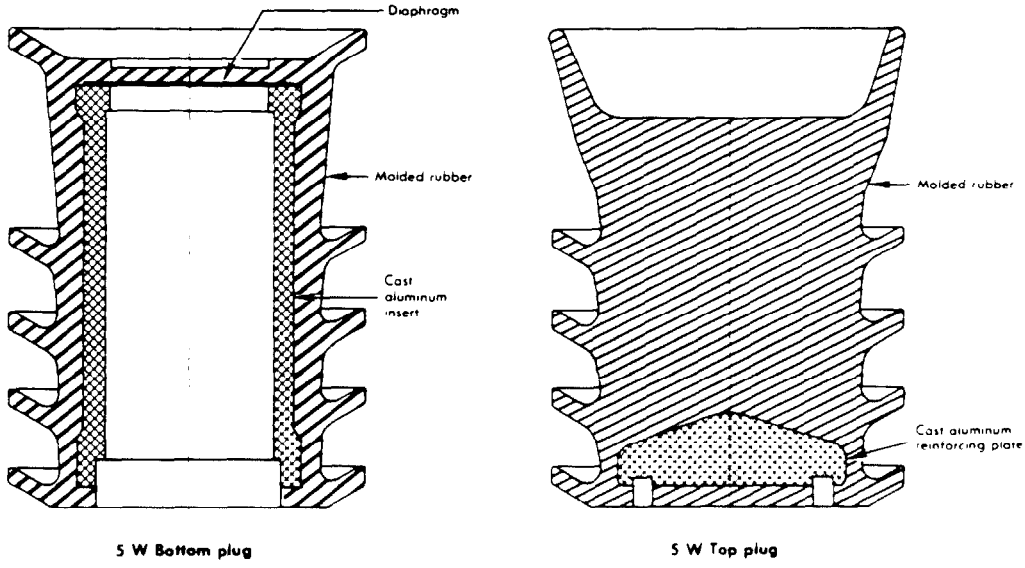


Figure 4.6. Cement plugs (Moore, 1974)

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5. DOWNHOLE, WELLHEAD, AND ANCILLARY EQUIPMENT

This section describes the selection and installation of downhole, wellhead, and ancillary equipment necessary for the operation of a leak-free injection system. As such, the following components are considered: bottom-hole configurations, completion practices, wellhead equipment, and water handling and surface equipment.

5.1 BOTTOM-HOLE CONFIGURATIONS

Selection of a bottom-hole configuration or bottom-hole completion method is an initial step in planning a well. Depending primarily on characteristics of the injection zone, a wide variety of bottom-hole completion methods are used, but generally can be categorized as those applied to competent formations and those applied to incompetent formations. Competent formations include limestone, dolomite, and consolidated sandstone that will stand unsupported in a borehole. The most commonly encountered incompetent formations are unconsolidated sand and gravel that will cave into the borehole if not artificially supported. There are, of course, formations that are generally competent but require some support to prevent sloughing of occasional incompetent intervals or to prevent fractured blocks from falling into the borehole (Warner and Lehr, 1977). The type of injection fluid used, and the possibility of well deepening or multiple-interval injection also affect the selection of completion method.

To date, injection wells have been completed using one of three methods or close variations of them: open-hole completion in competent formations; screened, or screened and gravel-packed in incompetent sand and gravel (also known as liner completion); and fully cased and cemented with the casing perforated in either competent or somewhat incompetent formations (Figures 5.1, 5.2, and 5.3).

5.1.1 Open-Hole Completion

In open-hole completion, casing is set just above the prospective injection interval, either before or after

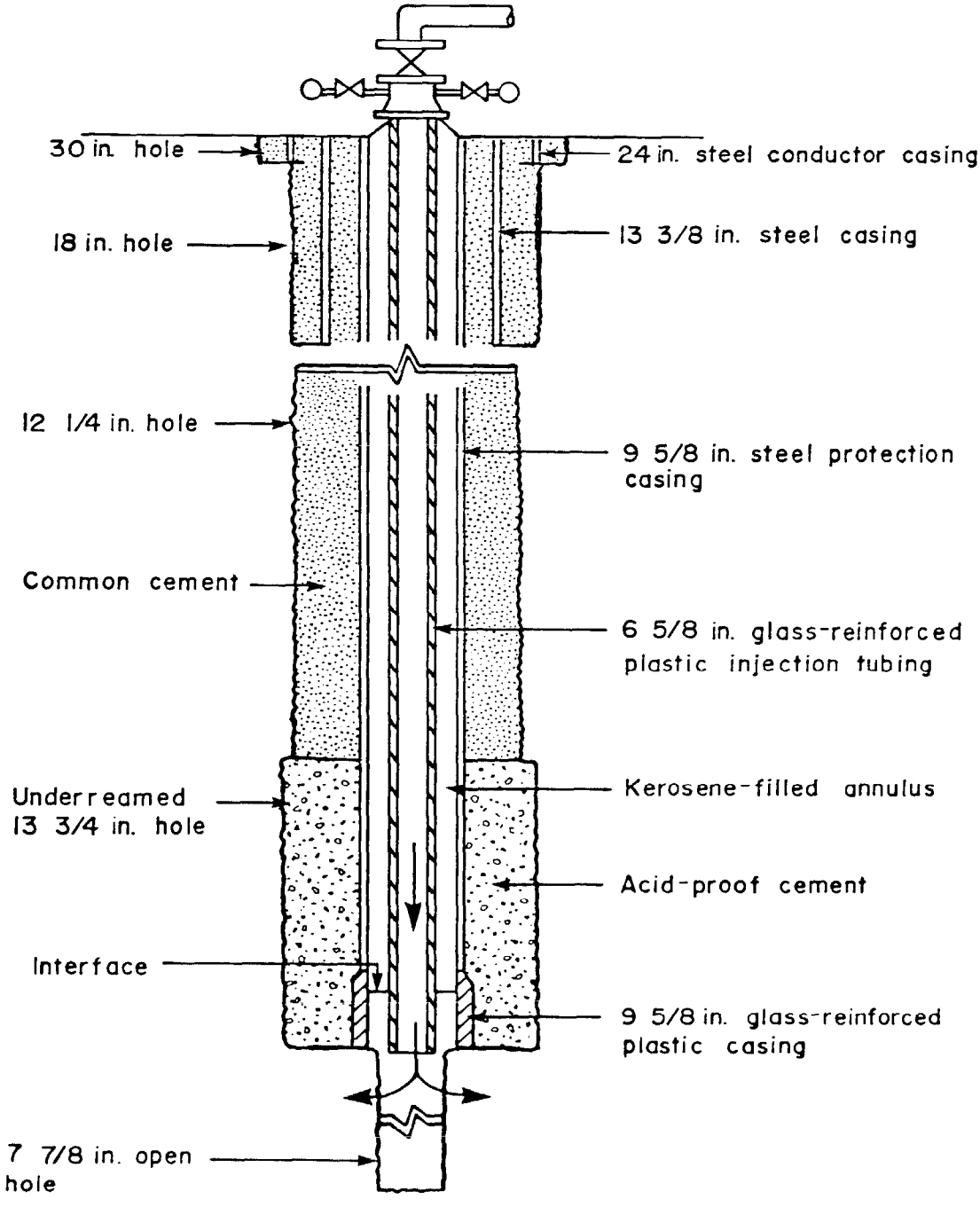


Figure 5.1. Well completion by the open-hole method (Barlow, 1972)

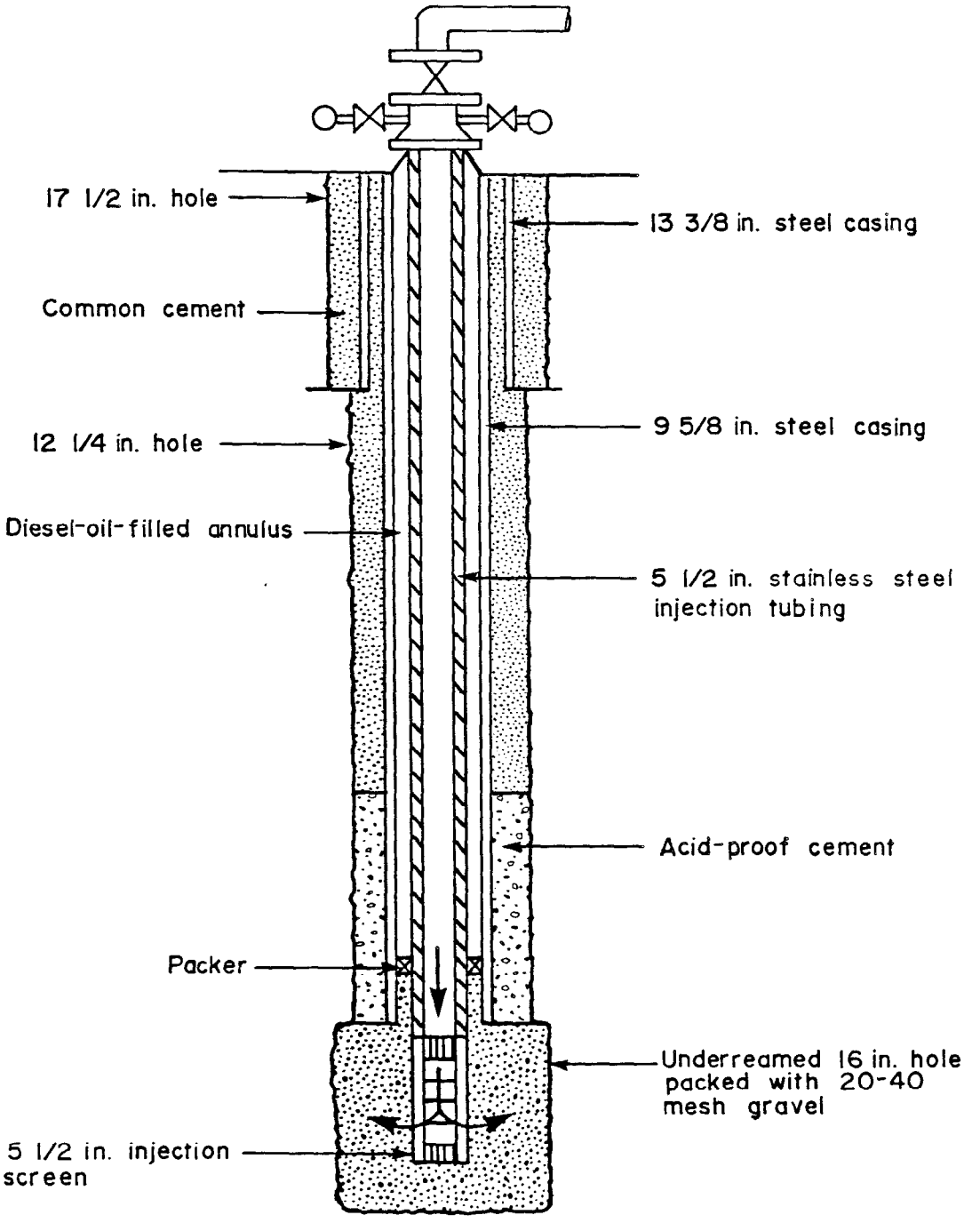


Figure 5.2. Well completion by the screen and gravel pack method (Barlow, 1972)

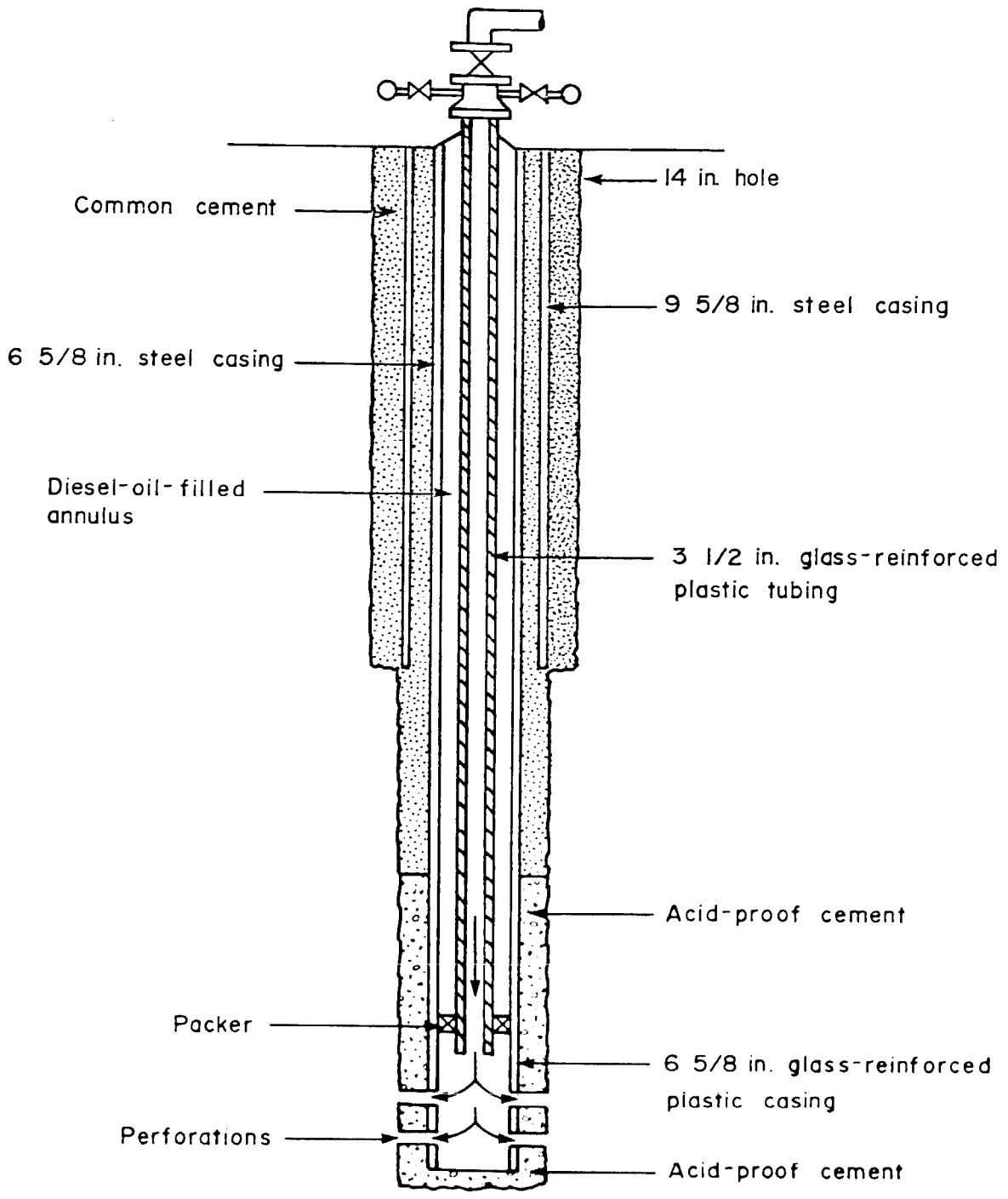


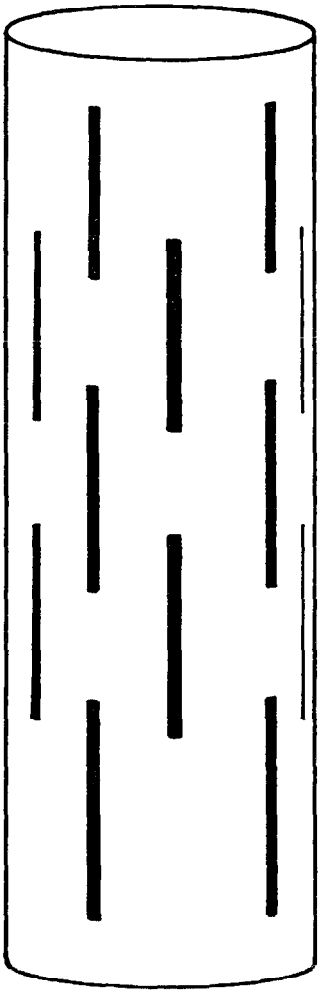
Figure 5.3. Well completion by the cased and perforated method (Barlow, 1972)

the injection zone is drilled, though the usual procedure is to set casing in advance (Petroleum Extension Service, 1971, 1977a). Advantages associated with open-hole completion include: the entire injection interval is exposed to the borehole; little casing and no screen is subject to corrosion by the formation or the injection fluids; no expense is incurred for perforation; the well can easily be deepened; and the well can be converted to a liner or perforated completion, or it can be underreamed to obtain a larger bore for gravel pack (Warner and Lehr, 1977; Allen and Roberts, 1978; Petroleum Extension Service, 1971). In addition to limitation of its use to only competent formations, other disadvantages of this method include limited selective injection into different zones and frequently required cleanout if the formation tends to slough. Also, the casing must be run without logging data on the immediate injection interval if set before penetration of the injection zone (Allen and Roberts, 1978).

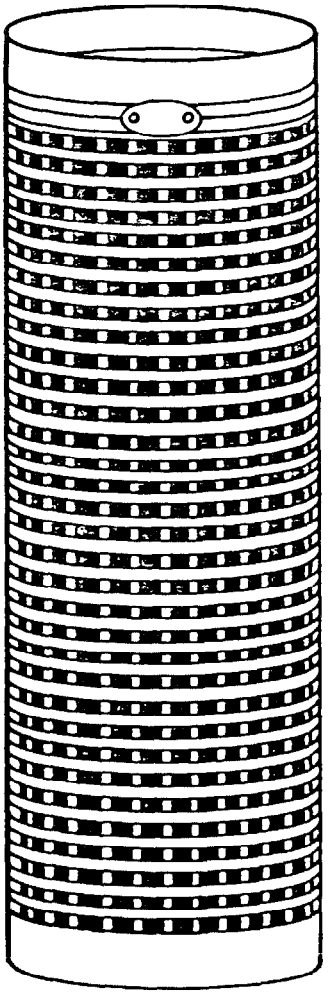
5.1.2 Screened Completion

Screens or liners are used as a means of formation support and sand control. Screens can be set immediately against the formation or can be set in an underreamed formation with gravel packing. Two types of screens are presented in Figure 5.4 and range from slotted pipe to fine-mesh welded screens. Depending upon the corrosiveness of the injection fluid, alloys such as stainless steel, bronze, galvanized steel, or plastics can be used as screening material. A detailed discussion of liner installation is presented by the Petroleum Extension Service (1971).

Many of the advantages and disadvantages of open-hole completion are also characteristic of the screened completion, or the screened and gravel-packed completion. An important benefit of the screen is that it provides some degree of wall support, an advantage in unconsolidated formations. Such support is also necessary in partially consolidated formations used as injection zones, as in the Gulf Coast of Texas and Louisiana, and in California (Warner and Lehr, 1977). Screened wells limit injection of fluids into selected intervals. If the screen is to be removed for plug-back, hole deepening, or squeeze cementing operations, difficulties can be encountered depending on the



SLOTTED CASING



WIRE WRAPPED SCREEN

Figure 5.4. Example of slotted casing and wire-wrapped well screens (Johnson Division, UOP, Inc., 1975)

mechanical condition of the screen and the forces acting upon the screen by the formation.

5.1.3 Perforated Casing Completion

In a perforated casing completion, the injection casing is installed and cemented through the full depth of the well. Selected injection zones are accessed by perforating the casing and the cement with a series of solid projectiles or small shaped-explosive charges. Shot holes are generally less than one-half inch in diameter and will penetrate the casing and several inches of cement and/or rock. This method of completion has been applied to wells in both hard and soft rock areas, and may be most useful for recompletion when additional injection capacity is needed or when it is necessary to abandon the original injection zone (Warner and Lehr, 1977).

Advantages of the perforated completion method include: adaptability to special sand control techniques; adaptability to multiple completion techniques; and provision of maximum support to the formation wall. The technique is not adaptable to special drilling practices that minimize formation damage since the injection well is drilled to total depth before the casing is set. The injection casing must be properly cemented to achieve zone segregation and to minimize formation damage in the injection zone. Cement and other borehole fluids that contact the formation during drilling and cementing operations increase the chances of formation damage that may impair flow rates and lead to higher injection-pressure requirements.

5.1.4 Well Stimulation

Well stimulation refers to chemical and/or mechanical-hydraulic treatment methods used to improve flow characteristics of the borehole and the adjacent formation. Stimulation methods can be applied to new wells after completion and before operation, but can be applied to older wells to maintain or to improve performance. This practice is often referred to as reworking, reconditioning, redevelopment, or rehabilitation.

The five basic stimulation methods are surging or swabbing, shooting, vibratory explosion, pressure acidizing, and hydraulic fracturing. Specific characteristics of the formation to be treated, the method of completion, and the method of operation influence the selection of the stimulation approach. Surging is used in developing shallow wells in unconsolidated sands where screened or liner completion is used to remove fine sediment from the vicinity of the well screen (NWWA, n.d.; Johnson Division, UOP, Inc. 1975). Shooting and other explosive stimulation methods traditionally were used to increase permeability in tight formations, but have been largely eliminated from use.

Stimulation methods used frequently in injection wells include those that improve formation permeability at the borehole and those that impact the injection zone at a distance from the well. Methods that affect the immediate borehole include washes, jet acidization, and detergent washing. These methods are used to remove drilling fluids or other deposits from the borehole face, or to improve permeability within a few inches of the borehole where formation damage from drilling may have occurred (Warner and Lehr, 1977). Hydraulic fracturing or pressure acidization techniques are designed to increase formation permeability significant distances from the well.

Pressure acidization or acid fracturing techniques have been extensively applied in injection wells, particularly in carbonate formations (Petroleum Extension Service, 1977b; Krueger, 1978; Williams and Whiteley, 1978; Gidley, 1978; Williams and Nierode, 1978). Injection of acid into an acid-soluble formation allows dissolution to enlarge voids and increase the permeability of the formation.

Various additives are used in acidization treatments to prevent the corrosion of casing. Corrosion inhibitors are used to prevent the acid from deteriorating steel casing while the acid is in the well. Acids used frequently are hydrocholoric (15 to 28 percent), acetic or formic (10 percent), and hydrofluoric (Petroleum Extension Service, 1981).

Hydraulic fracturing is discussed extensively in the petroleum literature (Allen and Roberts, 1978; Hubbert and Willis, 1970; Krueger, 1978; Petroleum Extension Service, 1981), and is used in developing fractures in tight sandstones or in carbonates to increase permeability. Hydraulic

fracturing employs fluid pressure to develop or extend fractures or cracks in the injection zone. Instead of using an acid to dissolve the matrix, cracks are kept open by injecting entrained proppants such as sand, walnut hulls, or other specialty materials. The fracturing fluids used are generally water-based, such as potassium chloride gels, although other fluids have been used.

A major concern in hydraulic fracturing is the determination of fracture orientation and fracture magnitude. If the fracture extends across the confining beds above or below an injection zone and proppants are injected, a path of migration can be formed. Further research is being conducted in this field to enable better predictions of fracture behavior and fracture propagation in confining zones. Production histories of oil and gas wells indicate the vertical extent of fractures, when in fact they do occur, is limited even if the fracture treatments have employed higher rates and volumes.

5.2 WELL-COMPLETION PRACTICES

Well completion refers to the method of providing a path for transporting the injection fluid to the injection zone. Primarily, well completion depends on the characteristics of the injection fluid, injection pressure, volume injected, length of service, and plans for recompletion (Petroleum Extension Service, 1977a). To a large extent, downhole environments dictate the completion practice.

The three basic completion practices used in injection wells are tubing and packer, tubing with open annulus, and tubingless. Variations on these practices have been adapted to meet a wide range of site-specific applications including injection into multiple annuli, and injection into a tubing with production through the annulus.

5.2.1 Tubing and Packer Completion

Tubing and packer completion can be used with open-hole, screened, and perforated casing bottom-hole configurations. Figures 5.2 and 5.3 are examples of such completion with perforated and screened/gravel-packed configurations. This type of completion isolates the casing from high

pressures and corrosive fluids and the packer prevents injection-fluid circulation in the tubing/casing annulus. In this example, the only points of well equipment and injection fluid contact are at the packer seal and the injection tubing, assuring a leak free system. However, tubing and packer components are exposed to the injection fluid and are subject to chemical degradation, especially where highly corrosive fluids are injected. Plastic coated, fiberglass, or corrosion resistant metal alloy tubing may be appropriate in certain applications (Donaldson, et al., 1974). Further protection from corrosion is possible by filling the annulus with noncorrosive fluids (Petroleum Extension Service, 1977a; Donaldson, et al., 1974).

Tubing and packer completion may be used more frequently than other methods because tubing can be replaced more easily than casing, it provides an additional level of protection to resources outside the casing, and it provides an additional opportunity for monitoring through the tubing/casing annulus (Warner and Lehr, 1977). Design criteria for tubing and packer systems reflects both the physical requirements of the equipment (capacity, axial loading, external pressure, internal pressure, joint stress, and vertical pressure differential), and also the corrosion resistant properties of the materials.

Tubing Selection, Handling, and Installation

Tubing-size selection is based on a series of technical and economic decisions which ultimately affect the casing diameter and drilling program of the entire well system. The primary technical consideration in this selection is the volume of injection fluid and its rate of injection. These considerations determine the velocity of flow and consequently, the amount of pressure dissipated through the tubing (friction pressure). The friction pressure loss for 100 feet (30.5 m) of tubing of various sizes can be calculated using Figure 5.5. This figure assumes injection of water at standard temperature and pressure, an "average" friction factor for the tubing, and laminar flow. Friction pressure losses for circumstances significantly different than the assumed ones would have to be calculated from friction loss equations given in texts on fluid mechanics.

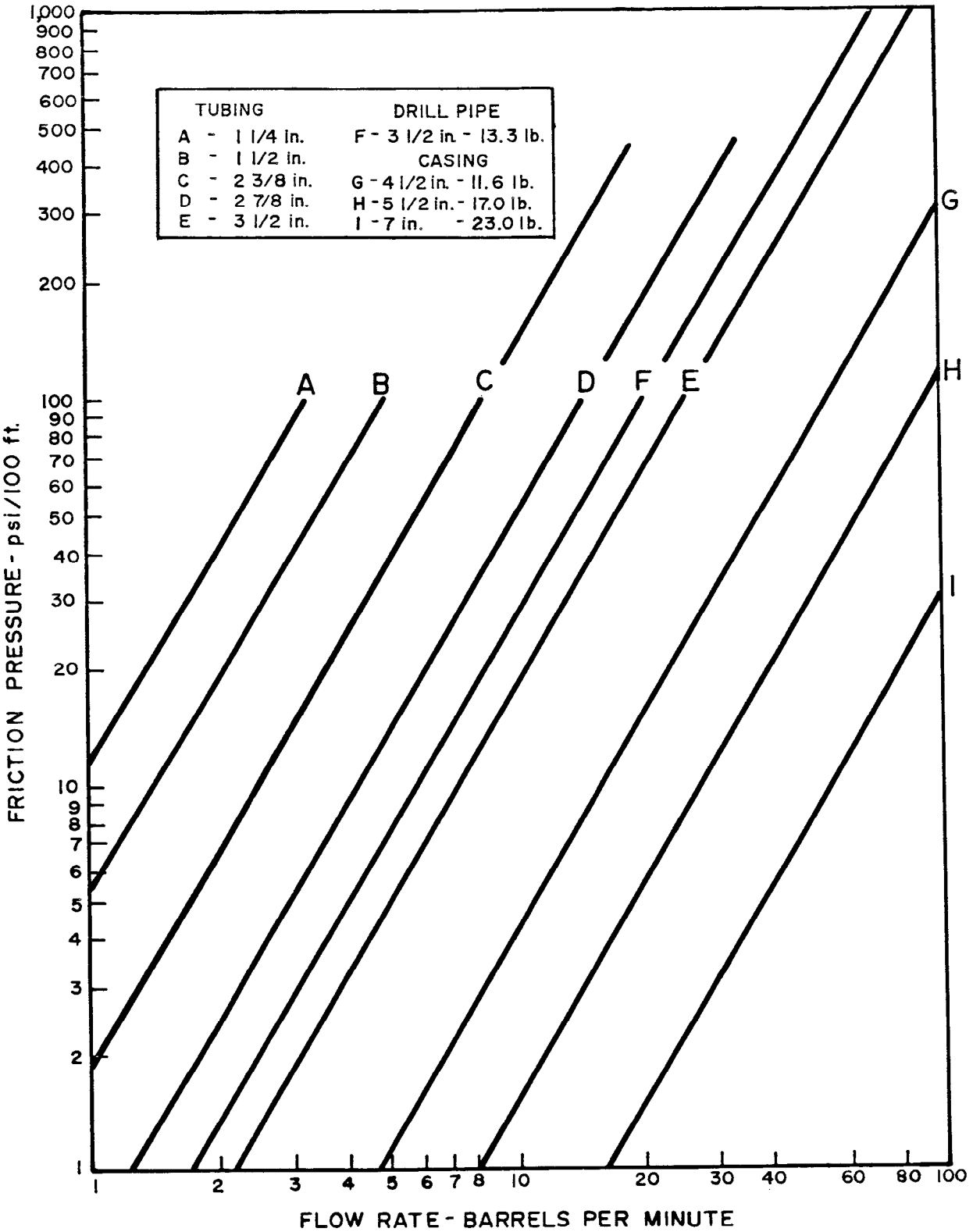


Figure 5.5. Friction pressure loss of common tubing and casing for fluid viscosity of one centipoise (Warner and Lehr, 1977)

Materials used for tubing include steel, reinforced plastics, fiberglass, and stainless steel. Sprayed-on plastic linings are also used, provided a satisfactory seal can be made at the tubing couplings. Plastic tubing, particularly glass-reinforced, is used in shallow wells since plastic tubing in tension has a low resistance to collapse and bursting. Bimetallic tubing has a thin-gage liner of resistant metal swedged to the base-metal wall and has been used successfully in some wells. The liner is folded over the end of the pipe and welded in position. As with plastic-lined steel pipe, couplings utilizing a liquid-tight gasket seal are used to prevent contact between the injection fluid and the unprotected steel of the coupling threads (Warner and Lehr, 1977). Final selection depends largely on the nature of the injection fluid and the physical requirements of the injection well.

Tubing should be inspected before it is run to identify such problems as mill defects, poorly machined threads, or shipping and handling damage to the pipe body, coupling or threads. Hydrostatic pressure tests of tubing and connections may be performed as the tubing is run in the hole. A successful pressure test is not conclusive proof of a lack of mill defects, since these may show up only after a number of cycles of pressure or temperature change.

Tubular goods can be damaged easily during handling, especially in particular grades. Approved practices for running tubing are recommended by the American Petroleum Institute (1980). These recommendations cover all aspects of tubing handling including hoisting the tubing, thread preparation, stabbing, joint make-up, and lowering.

In general, tubing failure can occur from improper selection, improper handling, as well as improper installation. Damage may result in failure of the well system and contamination of underground sources of drinking water.

Packer Selection and Installation

Packers are mechanical devices used to provide a seal between the tubing and the casing or the tubing and the open hole. Packers can be used to separate multiple injection zones, to protect casing from injection pressure and fluids, to isolate a given injection zone, to isolate casing leaks, or to facilitate subsurface safety control.

The two basic classes of packers are retrievable and permanent or drillable. Most packer assemblies are made up of several elements including the sealing element, slips, valves, friction blocks or drag springs, and safety joints.

In conventional packers, the sealing element is a hollow rubber cylinder or sleeve which when compressed causes the rubber to expand, contacting and pressing against the casing. Sufficient force will cause the sealing element to close the annulus between the tubing and the casing. Slips are used to support the packer inside the casing and to prohibit its movement. Some packers have two sets of slips, which work in opposite directions, prohibiting movement regardless of applied weight or differential pressure (Petroleum Extension Service, 1980).

In selecting a packer for an injection well, the following factors are considered: retrievability, reliability, differential pressure and temperature (i.e., formation or injection fluid conditions), corrosiveness of the injection fluid, well depth or bottom-hole completion, the overall objectives of the operation, and the tubing program and wellhead equipment. Each of the general packer types has site-specific applications. In extreme environments, those with high temperatures or with highly corrosive fluids, specialty packers are available from the manufacturers.

There are a variety of packers currently used for injection wells and other well completion purposes. A number of these packers and their applications are discussed below.

Weight-set packers are intended to hold against downward forces of tubing and formation pressure only and are suited for shallow, low-pressure applications where differential pressure from below is unlikely. A typical weight-set packer is shown in Figure 5.6. The weight of the tubing is used to expand the seal element and hold the packer. When employed in injection-well applications, the upward pressure exerted on the packer seal from the injection fluid must not exceed the combined forces of the weight of the tubing and annular pressure. Annular pressure can be increased or hydraulic hold-downs can be employed if a pressure differential exists.

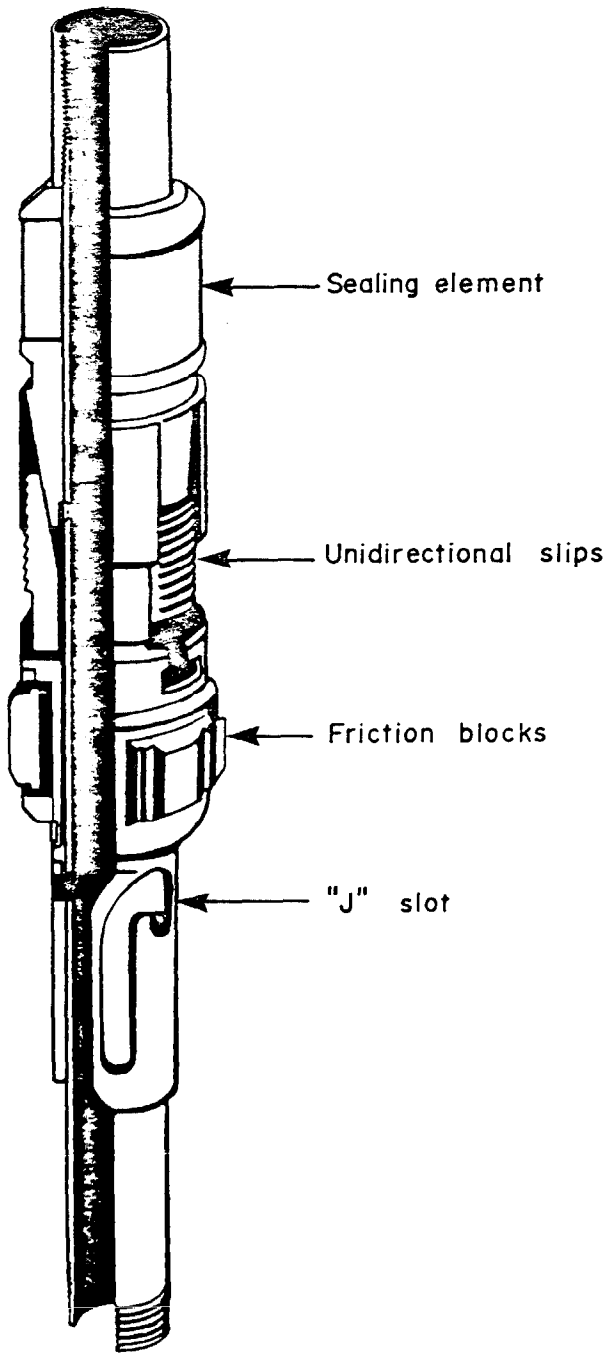


Figure 5.6. Weight-set packer (Allen and Roberts, 1978)

Tension-set packers are similar in design to weight-set packers run upside down. The packer is set by putting tension on the injection tubing. This type of packer is well suited for injection-well use since the injection pressure adds to the tubing tension and maintains the seal. Tension-set packers are sometimes used in shallow applications where the weight of the tubing is not sufficient to use a weight-set packer.

Rotation-set packers or mechanical-set packers are set and released by rotating the tubing. A schematic diagram of a rotation-set production packer is presented in Figure 5.7. This packer works independently of pressure or tubing force in either direction (Petroleum Extention Service, 1977c).

Conventional hydraulic-set packers use fluid pressure to drive a piston cylinder to activate the seal mechanism. The hydraulic pressure is applied through the injection tubing after the tubing is set in the packer. Hydraulic packers are more expensive than the other varieties and are best suited to complex multiple zone completions or applications in which high setting forces are required.

Inflatable or balloon packers can be used to develop a seal in either an open hole or a cased well. Inflatable packers are often used in wells with partially collapsed casing or in specialty injection operations where high pressure differentials are not experienced (Warner and Lehr, 1977). They are useful as formation packers or as external casing packers.

Permanent or drillable packers can be set by wireline, mechanical, or hydraulic means and generally will hold greater pressure differentials than most retrievable packers. As the name suggests, the packer must be broken up or drilled out because standard retrieval is not possible.

Regardless of the type of packer used or the method used of setting it, verification of seating must be made. In most packer types, the packer can be considered seated if it will support the weight of the tubing. In the case of tension-set packers, seating is indicated if the tension on the setting line or string of tubing is greater than that required to lift the tools in the hole (Petroleum Extension Service, 1980).

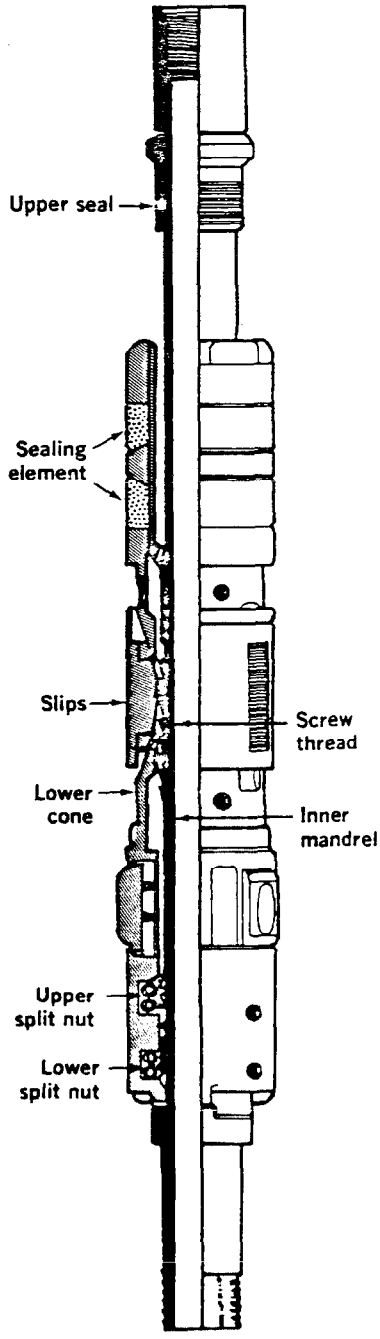


Figure 5.7. Rotation-set packer (Allen and Roberts, 1978)

Once the packer is seated properly, the installation can be tested for leakage. Most packer installations are tested for leakage initially by applying pressure to the tubing and watching for a pressure decline which may indicate a leak in the packer. If the packer has not been set to hold pressure, fluid may flow up the annulus. Monitoring pressure in the casing annulus will determine pressure leaks around the packer (Petroleum Extension Service, 1980).

Special Considerations/Hazards

In high temperature and pressure environments, or in situations where injection fluid temperatures vary, tubing expansion and contraction can unseat the packer or lead to leakage at the packer tubing interface. To lessen the negative impacts of tubing expansion or contraction, temperature or pressure differentials must be minimized or special hardware must be employed. The use of specially weighted annular fluids and surface adjustment of injection fluid temperatures can help minimize problems. In cases where these procedures are impractical or insufficient to fully mitigate problems, use of expansion receptacles is warranted.

Expansion receptacles are used to allow tubing to move freely during expansion and contraction while maintaining a tight seal in a fully seated packer. This is particularly important in deep wells in situations where large changes in temperatures are likely. These tubing/packer connections can eliminate the high tensile or compression stress exerted on tubing where statically attached to the packer (Petroleum Extension Service, 1977, 1971; Allen and Roberts, 1978).

High temperature environments can directly affect packer seals and the operation of release mechanisms. Conventional packer sealing elements, such as Hycar rubber, are generally functional up to 300°F to 350°F (148.7°C to 176.5°C). For higher temperature applications, special sealing elements and specialty packers are used. For example, double sealing elements, metal back ups, and advanced materials (e.g. Teflon) are used to handle increased temperature, pressure and corrosiveness (Allen and Roberts, 1978). These are readily available from the manufacturers.

High-performance packer seals are designed to resist corrosion and high differential pressures. Harder rubber and narrower seal clearances are used for high-pressure operations. Exposure to chemical changes, and differential pressures can cause changes in rubber characteristics and resiliency, and can dissolve the seal in some cases.

Annular Fluids

Annular or packer fluids are used to eliminate downhole pressure differentials and to inhibit corrosion. Packer fluids provide hydrostatic head by exerting pressure across the packer seal. This pressure can be adjusted by varying the density of fluids to eliminate large pressure differentials above and below the packer. In deep wells where potentially high temperatures are encountered, packer fluids can be selected that remain stable and do not convert to corrosive chemicals or contain them. (This is particularly important in deep wells since the high tensile strength steel used tends to be more vulnerable to corrosion than ordinary steel.)

The basic categories of packer fluids are suspended solids-free liquids, water-based muds, and oil-based muds. Solids-free liquids include oil-based and water-based solutions and allow the addition of corrosion inhibitors where appropriate. Oil or diesel fuel are examples of solids-free packer fluid. Oil-based fluids are less dense than aqueous fluids resulting in a lower hydrostatic head, limiting their application in high pressure wells. Clear water-based or aqueous-chemical solutions can be used where higher densities are required. Salts can be added to adjust densities from 8.4 lb/gallon (1 kg/l) freshwater up to 16 lb/gallon (1.9 kg/l) for a high density calcium chloride/zinc solution. Some salt solutions can be corrosive and can require inhibitors (e.g. sodium chromate) for use with freshwater-based fluids.

Water-based packer fluids can be used in certain injection wells; however, in high temperature wells aging accelerates, the pH drops, and the solids settle. As a result, the corrosion protection quality of the fluid is diminished and the settled solids may inhibit workovers.

Oil-based packer fluids, such as emulsions or muds, can be used over a wide density range (7.8 to 22.0 lb/gallon

(0.93 to 2.6 kg/l)], and are considered noncorrosive. Gelling agents are available to prevent solids from settling and causing workover problems. Additives with oil can be used to wet the casing and to inhibit corrosion (Petroleum Extension Service, 1980).

In each of these categories, fluid selection is a function of the cost, density, and corrosiveness. Also, the temperature ranges encountered will impact the selection of packer fluids. The relative advantages and limitations of packer fluids are outlined by the Petroleum Extension Service (1980).

5.2.2 Tubing with Open Annulus Completion

This special type of completion has been used in applications with highly corrosive injection fluids such as steel pickling liquors (Donaldson, et al., 1974; Bayazeed and Donaldson, 1973). A packer is not used at the bottom of the injection tubing as a conventional seal for the annulus; instead, electrodes can be installed at the annular fluid/injection fluid interface to detect any movement of injection fluid into the annulus (Donaldson, 1978) (Figure 5.8).

To eliminate migration into the annulus, a hydraulic seal is established by injecting noncorrosive fluid into it or by floating a noncorrosive fluid of different density in it. In one case in which pickling liquor was injected, water was pumped continuously into the annulus at a pressure slightly greater than the injection pressure, allowing a constant flow of water through the annular space. The conductivity of the water at the bottom of the tubing was monitored to detect accidental entry of acid (Donaldson, 1978). Fiberglass or compatible metal alloy injection tubing is used for its resistance to low pH injection fluid. The injection tubing, as shown in Figure 5.8, is extended below the casing shoe into the open-hole configuration, never exposing corrosive injection fluid to the well casing at any point.

Another variation of the hydraulic seal is illustrated by Barlow (1972) in Figure 5.1. In this application, an interface is established between a hydrocarbon fluid in the annulus and an aqueous injection fluid. Special

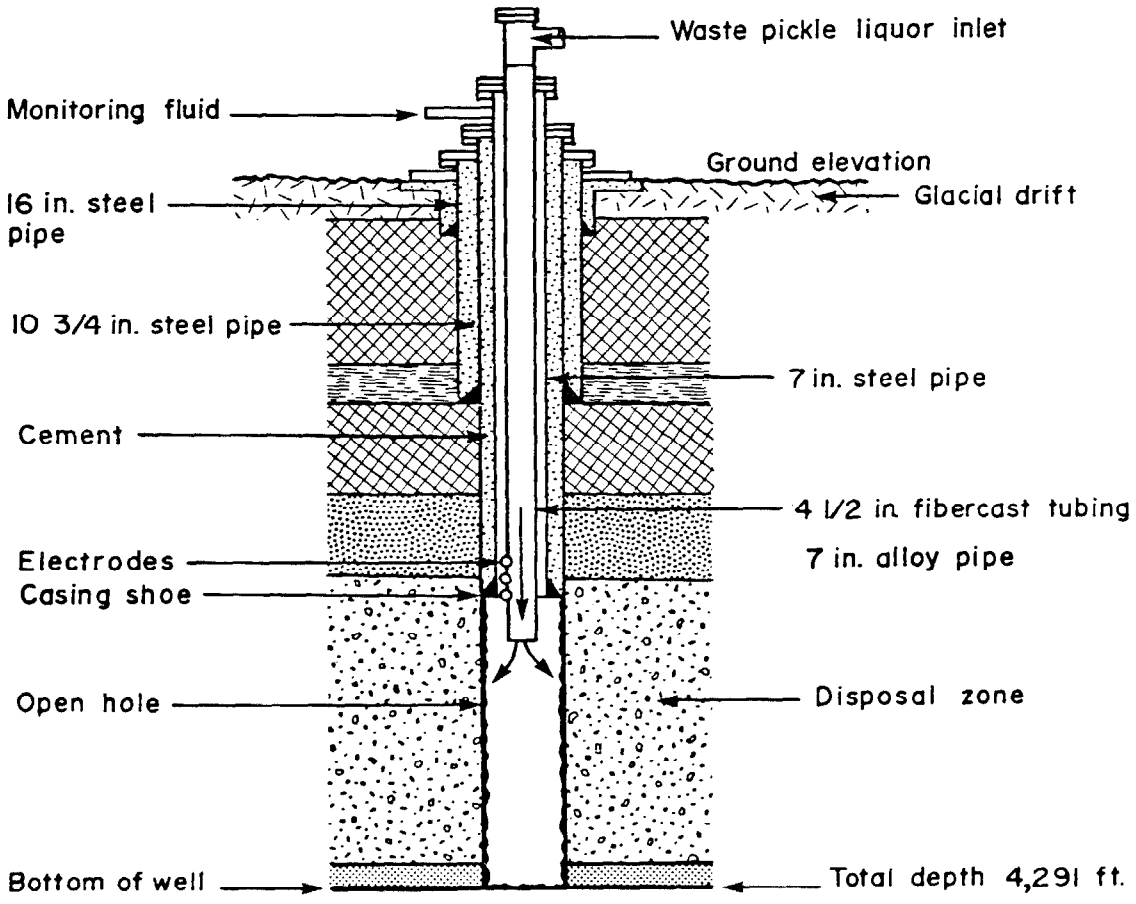


Figure 5.8. Principles of open-annulus completion (Donaldson, et al., 1974)

fiberglass-reinforced, plastic casing is used in the bottom of the hole in the interface zone. Acid-proof cement is also used in the lower part of the casing string.

5.2.3 Tubingless Completion

In a tubingless completion, fluids are injected directly through permanently installed injection casing. This method can be used with any of the bottom-hole configuration practices described. A principle disadvantage of this method is that permanent casing material is exposed directly to the injection fluid. Although plastic coatings or liners can be used, the competence cannot be guaranteed and they increase the cost of the well significantly (Donaldson, 1978).

Tubingless completion is used in applications where low pressures are encountered, such as uranium leaching, oil-shale, and modified in-situ retorts. Also, tubingless completion has been used in injection well operations where the lifespan is very limited or where the injection fluid is noncorrosive.

Periodic pressure tests of the well or other mechanical integrity tests may be run to determine if leakage is occurring. Since no tubing/casing annulus exists, there is no possibility of an ongoing leakage check as there is with annular pressure monitoring.

5.3 WELLHEAD EQUIPMENT

The wellhead is the link between the injection-fluid feed system and downhole equipment. The wellhead may consist of as little as a master valve on the tubing. Figure 5.9 illustrates a simple wellhead system with basic meters, filters, and valves.

5.3.1 Wellhead Design and Installation

Wellhead equipment is located at the surface and is designed to support and to seal casing or tubing and to

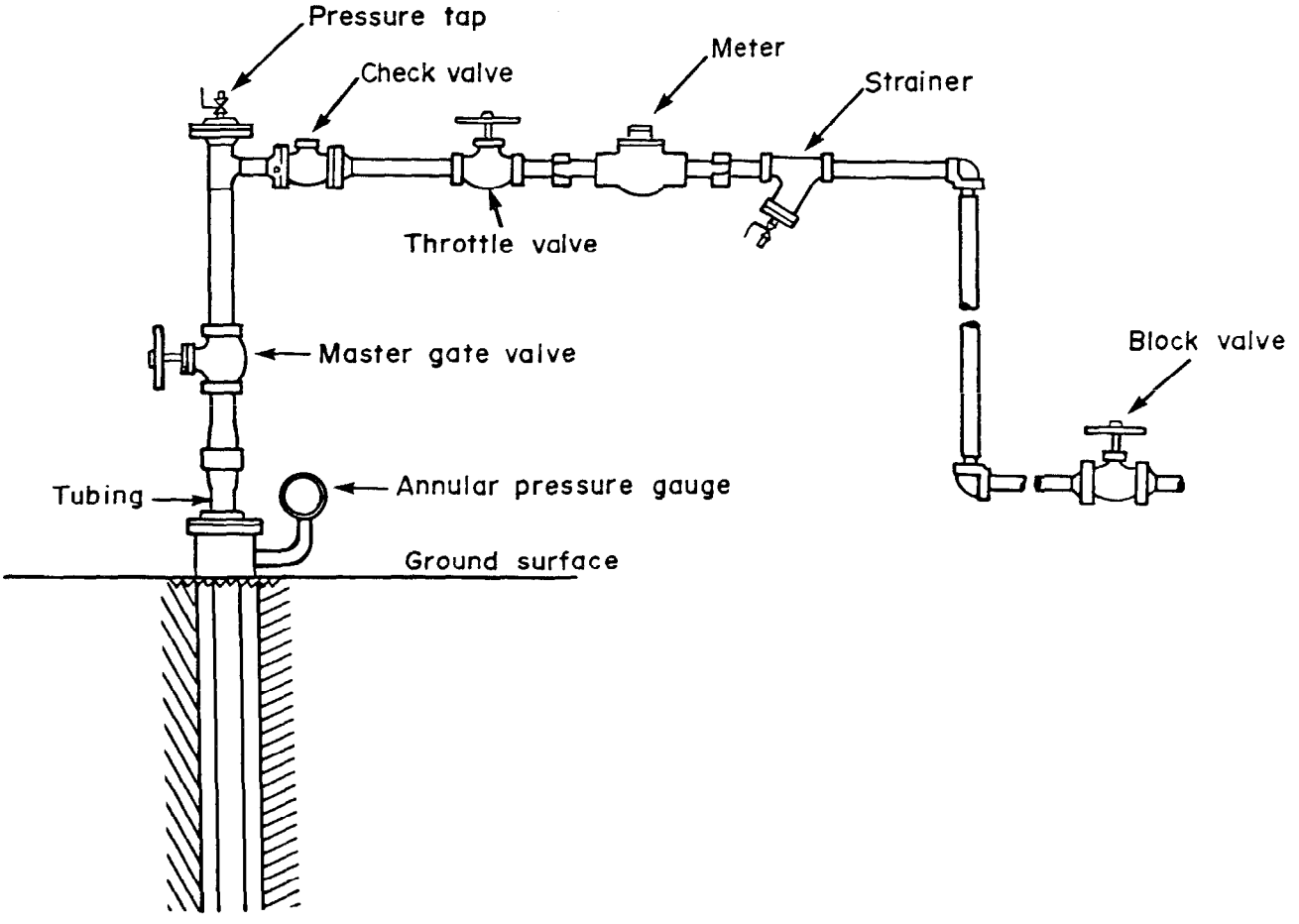


Figure 5.9. Simplified wellhead assembly showing meters and valves (API, 1978)

permit controlled flow to or from the well. Installation of wellhead equipment is done during the drilling and completion processes.

The wellhead is attached to the surface casing to establish a foundation for blowout control equipment. If intermediate casing is run, the top length of the string, supported in a casing hanger, is set in and hung from a casing flange. Each successive string of casing and tubing is supported and sealed within another spool added to the wellhead stack. The complete wellhead arrangement, therefore, consists of a flange and a series of spools, each supporting an individual string of casing (Figure 5.10).

5.3.2 Metering/Monitoring Requirements

The wellhead assembly has the capability of flow metering and injection-pressure monitoring. In addition, an annular pressure metering point is generally built into the wellhead assembly.

Wellhead meters are available in a variety of types. The orifice meter is most useful where large volumes of fluid are injected. In a controlled fluid injection project, positive displacement meters (such as rotating disc, vane, and turbine type) can be used.

Records of key injection-well parameters, total volume, injection rate, injection pressure, pretreatment measures (additives), and annular pressure, are generally kept to analyze the performance of the system and detect mechanical failures. Problems with an injection well can be indicated by gradual trends on pressure/rate charts or by sudden increases or decreases in annular or injection pressures. A sudden change in annular pressure may indicate a tubing or packer leak or it could be a result of a casing failure, allowing fluid entry from a natural or charged fluid zone. An increase in wellhead pressure or a decrease in injection fluid volume could be the result of formation plugging, tubing and packer restriction, increases in the formation pressure, or breakthrough to a neighboring well or into another formation (American Petroleum Institute, 1978).

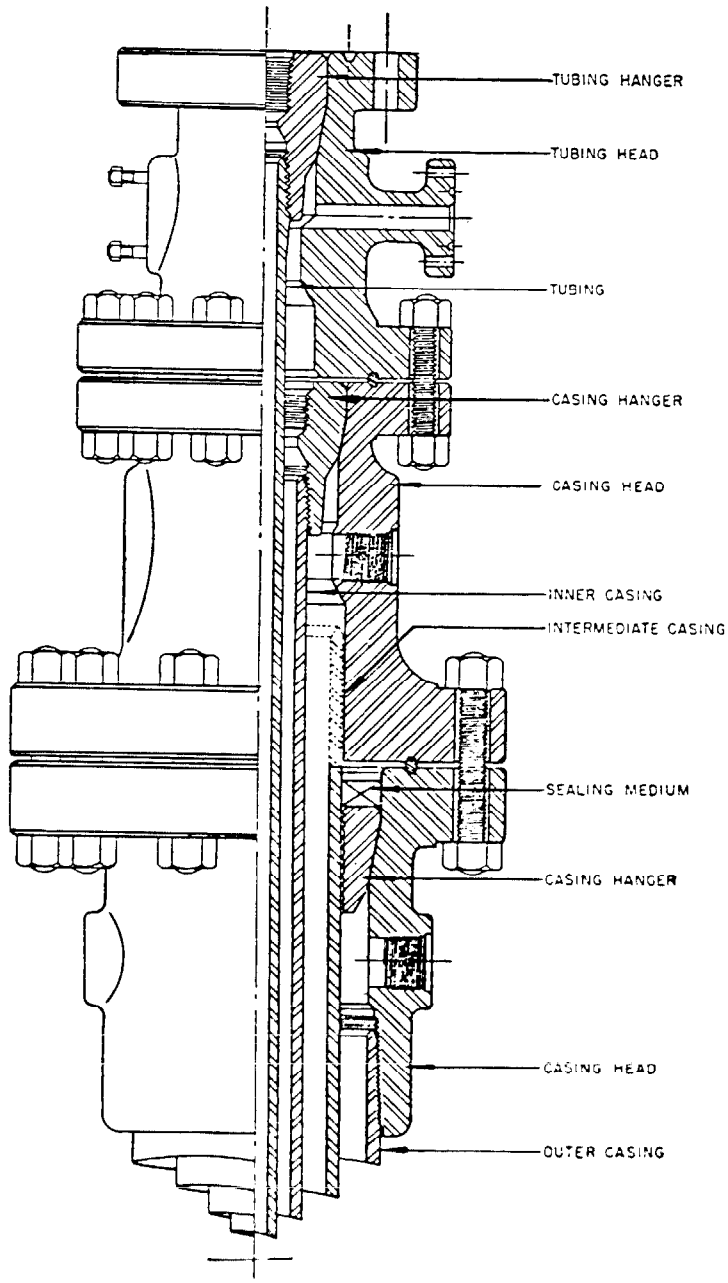


Figure 5.10. Details of typical wellhead assembly (API, 1981)

Metering and pressure recording devices require periodic maintenance and monitoring or erroneous data could be obtained. Strainers, screens, and filters require regular flushing to prevent clogging with solids. Also, orifice meters need routine checking with a dead weight tester to assure accurate readings (American Petroleum Institute, 1978).

5.3.3 Flow Regulation Equipment

In addition to varying the injection rate, flow regulation is accomplished by the use of special shut-off or check valves and by the use of flow control chokes. Automatic shutoff valves are used at the wellhead to close automatically in response to pressure changes. The automatic shut-off mechanism is composed of the valve body, the actuator (closing mechanism), and the pilot (sensing assembly). The function of this mechanism is to protect both the downhole equipment and the ground-water system. When a pressure change occurs, indicating a leak, the shut-off valve arrests the flow. Check valves can be designed to close gradually to avoid destructive hydraulic phenomena like water hammer effects.

5.4 INJECTION FLUID HANDLING AND SURFACE EQUIPMENT

In some instances, pretreatment and filtration, surge protection, and pumping of the injection fluid may be required. Surface equipment may also be required in providing a constant flow of corrosion resistant water to the annulus.

5.4.1 Pretreatment

Injection fluid pretreatment is done to limit corrosiveness, to limit the levels of suspended solids, and to assure compatibility with formation fluids as well as with the formation. Two surface configurations are used in pretreatment and injection fluid handling, open and closed. An open system (Figure 5.11) can be used with fluids that

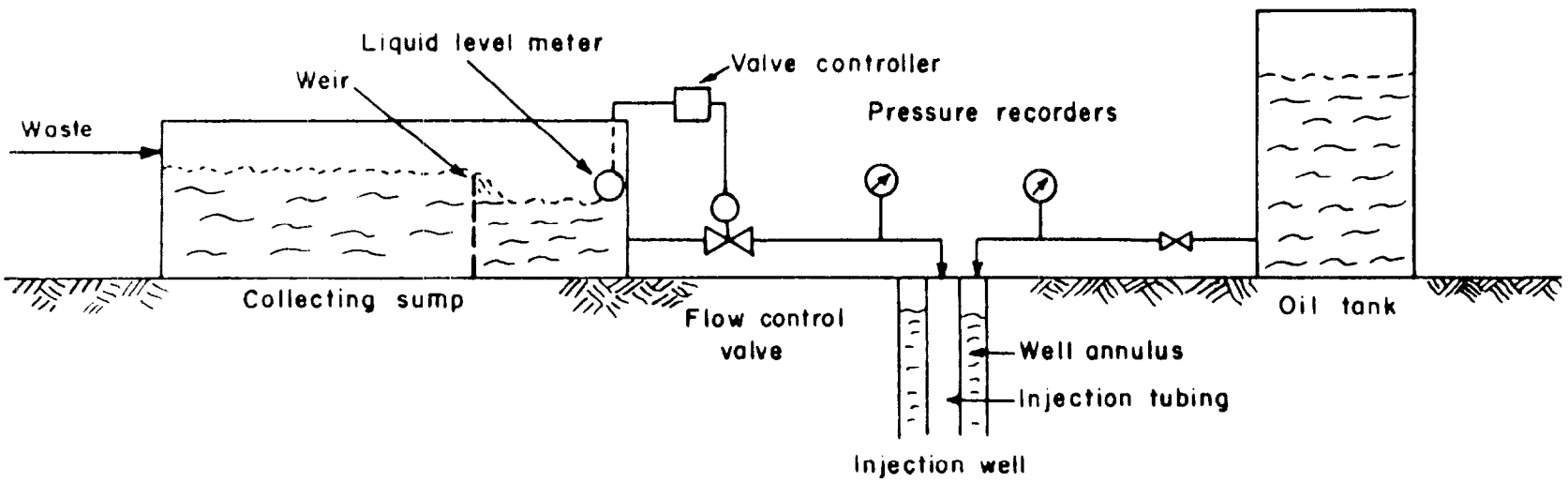


Figure 5.11. Open injection-fluid treatment system (Donaldson, 1978)

are free of suspended solids and that will not be chemically altered by contact with oxygen. In this example, the fluid is injected with gravity feed and is controlled by a metering valve.

More reactive injection fluids are pumped through a closed injection system (Figure 5.12). Pumps are used to generate sufficient pressure to maintain an acceptable flow rate. Filtering and pH adjustment limits corrosion and plugging. A surge tank is employed to assure consistent delivery of fluid and to eliminate shocks to the system that could result in pressure surges or water-hammer effects. Highly complex systems, as pictured in Figure 5.13, are the result of further pretreatment needs (Donaldson, 1978). Effective filtration can be particularly important when injecting into noncavernous formations. Injecting into strata possessing interstitial permeability may require removal of particulate matter larger than 3 microns.

5.4.2 Pumping Equipment

Pumps are used for fluid injection if gravity flow into the well is not adequate to provide the desired flow rate. Positive displacement, plunger-type positive displacement, centrifugal, and piston-type pumps are in use. Centrifugal pumps include single stage and multi-stage horizontal and vertical pumps and are well suited for lower-pressure service [i.e., less than 300 psi (2.1×10^6 N/m^2)]. Turbine and single-stage centrifugal pumps capable of high-pressure operation are also available. Centrifugal pumps generally have heavy casing walls which are important for the injection of corrosive fluids. Also, centrifugal pumps with limited pressure ratings are less apt to overpressure a formation.

The type of pump and drive best suited for an injection project is determined during system design by evaluating the expected operating volume and pressure. Economic factors such as fuel availability, initial cost, maintenance cost, operation cost, and parts availability are also considerations. Pumps that are fitted for salt-water service or injection of other corrosive fluids may have to be designed using special materials (metallic materials

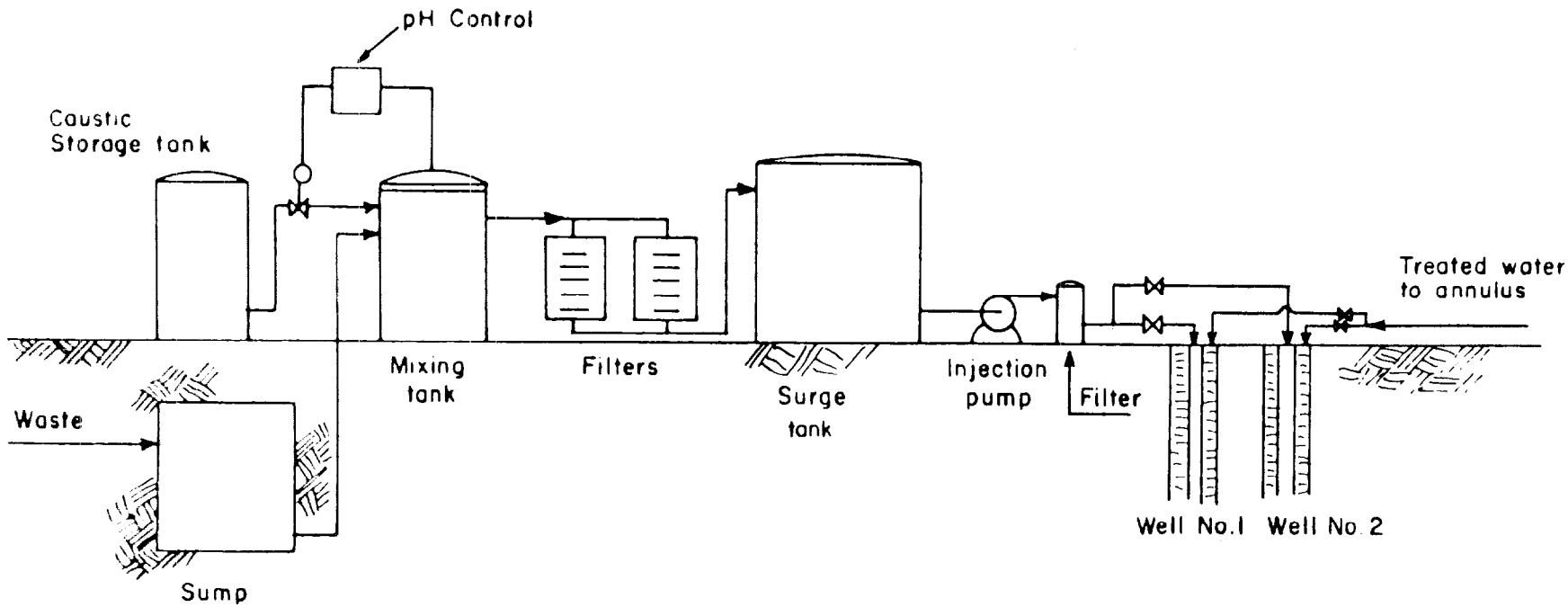


Figure 5.12. Closed injection-fluid treatment system (Donaldson, 1978)

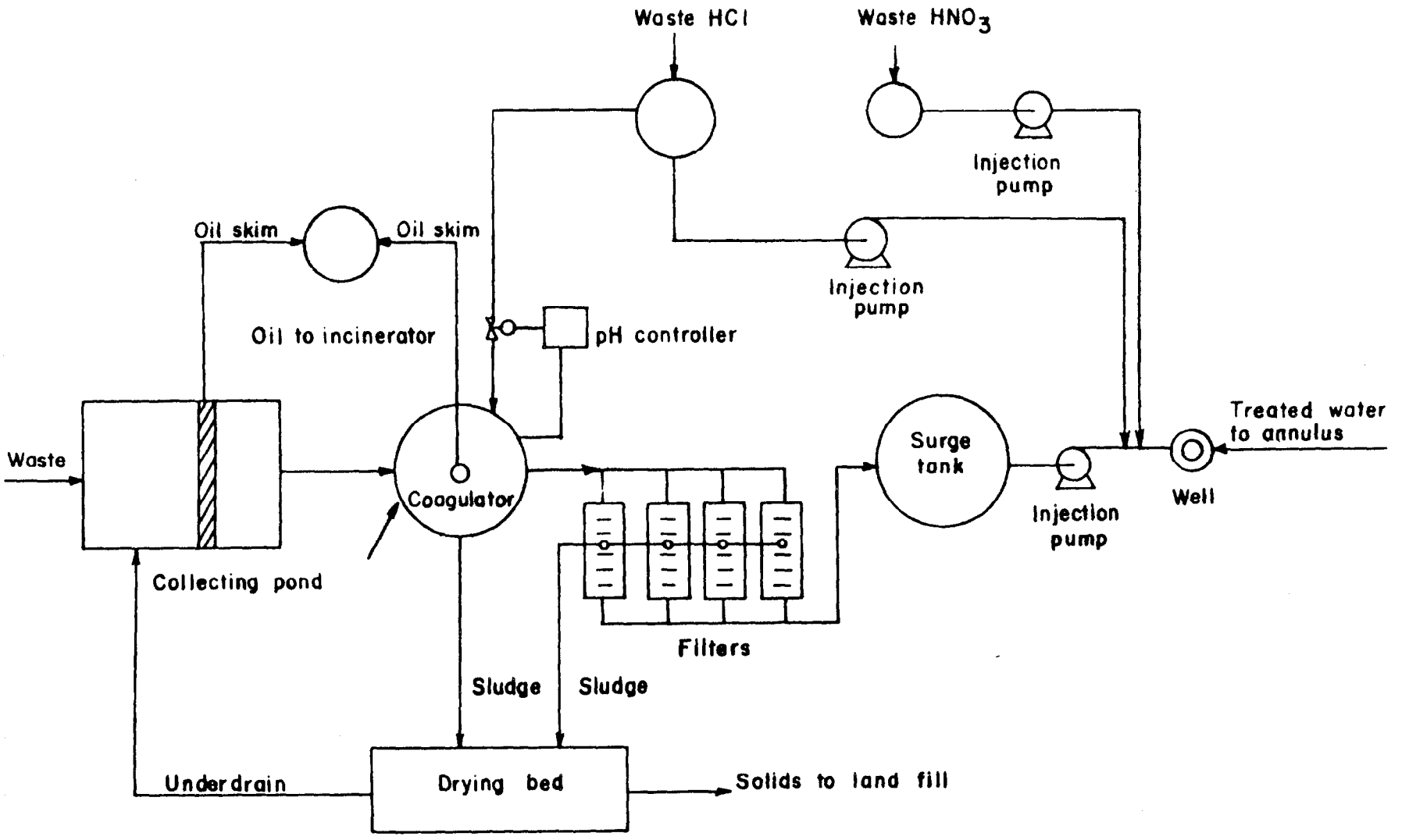


Figure 5.13. Schematic drawing of complex injection-fluid treatment system (Donaldson, 1978)

like stainless steel, aluminum, bronze, cast iron, or non-metallic materials, like ceramics), for all parts that contact the injection fluid.

The pump drive can be equipped for automatic shutdown in the event of abnormal operating conditions that include high pump discharge pressure, low pump discharge pressure, low fluid level in the suction tank, or excessive pump vibration. It is important that automatic shutoff mechanisms operate in an incremental mode so that surges are avoided.

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6. CORROSION AND CORROSION CONTROL

The effects of corrosion on injection-well systems require serious attention during design and construction. Corrosion can cause deterioration and eventual destruction of injection-well components, such as tubing and casing, resulting in the leakage of injection fluids into an underground source of drinking water or other resources. In addition, corrosion products may plug the injection well or the formation into which fluids are being injected.

Technically, corrosion refers to the destruction by reduction of a base-metal material to a more stable component, such as an oxide or a sulfide, by a chemical or electrochemical reaction with its environment. Certain metals, such as magnesium, zinc, aluminum, and iron, are more reactive than others, and hence corrode more readily.

The term corrosion is also used to describe other forms of degradation of materials. A common example of this phenomena is the dissolution of plastic materials by organic solvents. Although not electrochemical in nature, this form of corrosion results in deterioration and loss of material due to chemical attack.

In injection-well systems, corrosion involves both the internal corrosion of tubing, casing, and wellhead equipment from electrochemical reaction of the metals with the injection fluids, and the external corrosion of casing from contact with the soil or the water in which the well is placed. For electrochemical corrosion to occur, it is necessary for conditions to be established which develop an electrolytic cell composed of an anode, a cathode, an electrolyte, and an external connection. Typically, corrosion-control practices are intended to remove one or more of these conditions.

The anode and the cathode normally exist at two different places on the metal surface. The anode is the area where the oxidation of metal or corrosion occurs, and the cathode, is the area where reduction of metal (plating-out) takes place. For example, in the corrosion of steel, iron is oxidized to the ferrous ion at the anode and the ion goes into solution:

$$Fe^{o} \rightarrow Fe^{++} + 2e^{-} \qquad (6\text{-}1)$$

Electrons liberated at the anode by oxidation flow through the metal to the cathode area. At the cathode, the hydrogen ion in the adjacent aqueous solution picks up the two electrons from the metal to form hydrogen gas which bubbles off:

$$2H^{+} + 2e^{-} \rightarrow H_2 \text{ (gas)} \qquad (6\text{-}2)$$

These two electrode reactions result in a difference in electric potential between the anode (positive potential) and the cathode (negative potential).

An electrolyte is needed to provide the medium for current flow between the anode and the cathode. Water and its dissolved mineral salts serves this purpose. In solution, dissolved salts separate into two types of ions, anions (negatively charged) and cations (positively charged). These ions are responsible for the ability of water to permit corrosion currents to flow, with anions moving to the anode and cations moving to the cathode.

The rate of corrosion is influenced by a variety of factors, including the characteristics of the metal, the substances in and conductivity of the electrolyte, the deposition of corrosion products, the polarization of the electrodes, the temperature of the corrosion environment, and the presence of mechanical action such as velocity of water movement over the metal. More detailed discussions of corrosion theory can be found in books by Evans (1960), Uhlig (1962), and Weber (1972).

6.1 TYPES OF CORROSION

There are many types of corrosion which can occur in injection-well systems. The majority are electrolytic corrosion which occur from exposure to various dissolved substances in water. The various types of electrolytic corrosion can be explained by referring to the basic electrochemical reactions involved. The other types of corrosion encountered in injection-well systems primarily

consist of the deterioration of non-metals, such as plastic injection tubing, caused by organic solvents in injection fluids.

6.1.1 Oxygen Corrosion

Oxygen dissolved in water causes rapid corrosion of metal (Allen and Roberts, 1978). The effect of dissolved oxygen is realized at the anodic area of the metal where the insoluble metallic hydroxide (rust) is precipitated. The oxygen corrosion reaction for iron in the absence of other influencing constituents proceeds as follows (Ostroff, 1965):

$$Fe + 2H^{+} \longrightarrow Fe^{++} + 2H^{o} \qquad (6\text{-}3)$$

$$2H^{o} + 1/2O_2 \longrightarrow H_2O$$

$$2Fe^{++} + 1/2O_2 + H_2O \longrightarrow 2Fe^{+++} + 2OH^{-}$$

The corrosion rate is limited by the rate at which oxygen is delivered to the anodic area. In a closed injection system (out of contact with air), the reaction will continue only until the dissolved oxygen in the injection fluid is consumed (Warner and Lehr, 1977). In open systems, where air can enter the injection fluid, corrosion continues as the oxygen supply is replenished. In general, with increasing dissolved oxygen levels the corrosion rate progresses until a point is reached at which the flow of oxygen becomes limited by the barrier of metallic hydroxide developed on the anodic surface.

Oxygen corrosion is enhanced by the presence of dissolved cnloride and sulfate salts. Generally, corrosiveness increases with increasing salt concentration until a maximum is reached after which corrosiveness decreases. The initial increase is due to the electrolyte conductivity increase, and the subsequent decrease results from the decreased solubility of oxygen (Uhlig, 1962).

Carbonate minerals inhibit oxygen corrosion, acting to counter the acceleration effect of salts in water containing dissolved oxygen. The degree of inhibition is dependent on the relative concentrations of carbonate alkalinity and the chloride and sulfate salts. When calcium is associated with the carbonates, there is further capacity for protective action (AWWA, 1971).

The rate of corrosion due to dissolved oxygen generally increases with increasing temperature. Basically, higher temperatures cause more rapid chemical-reaction rates. However, when the temperature becomes high enough to decrease oxygen solubility, the corrosion rate can be expected to decrease in open systems. In a closed system, the oxygen cannot escape and the corrosion rate continues to increase with increasing temperature (Ostroff, 1965).

The velocity of the injection fluid can also affect the rate of corrosion. As the velocity increases, the replenishment of oxygen to the metal surface becomes higher and consequently the corrosion rate increases. Also, further increases in velocity of the injection fluid can cause mechanical scouring of corrosion products, thus removing any protective film that might help reduce the corrosion rate.

Injection-fluid pH also affects the rate of corrosion of solutions containing oxygen. For iron, the corrosiveness of a fluid generally increases as pH decreases. In the pH range of 4 to 9.5, the iron surface is coated by corrosion reaction products, and corrosion progresses as oxygen diffuses through this layer. Below a pH of 4, the corrosion products dissolve and consequently, more rapid corrosion ensues (Ostroff, 1965).

Oxygen corrosion pits the metal surface at an even depth. The pit develops at a localized anodic point and continues by virtue of a large cathodic area surrounding the anode (AWWA, 1971). Pits may be sharp and deep or shallow and broad. Additionally, a corrosion product may form over these pitted areas. In down-hole oxygen corrosion, distinct lumps called tubercules of oxygen corrosion product may occur. These are caused by aggregation of iron bacteria and mixed carbonates and hydrated metal oxides.

A special type of oxygen corrosion is caused by differential aeration cells, a result of differences in oxygen

concentration between two parts of the system. Differences in dissolved oxygen concentrations cause differences in the solution potential of the same metal. In differential aeration cells, corrosion occurs at the area of the metal where oxygen concentrations are low. An adjacent area of relatively higher oxygen concentration serves as the cathode in the reaction.

Corrosion products, chemical precipitates, or other debris on a metal surface hinder oxygen diffusion by covering the metal at local areas. These circumstances can result in the development of oxygen concentration cells with corrosion taking place under the deposit.

The growth of microorganisms in injection wells can also result in the formation of localized oxygen concentration cells by effectively shielding parts of the metal surface from oxygen (Ostroff, 1965). Corrosion can therefore occur under areas of tubing or casing covered by slimes or masses of bacterial growth.

6.1.2 Carbon-Dioxide Corrosion

Carbon dioxide dissolved in water can contribute to the corrosion of steel, but for equal concentrations it is much less corrosive than oxygen (Ostroff, 1965). Carbon-dioxide corrosion of well components is of particular concern in enhanced-oil-recovery operations involving carbon-dioxide miscible injection systems. In these flooding operations, carbon dioxide is injected before, after, or alternating with water.

When dissolved in water, carbon dioxide forms carbonic acid:

$$CO_2 + H_2O \longrightarrow H_2CO_3 \text{ (Carbonic Acid)} \qquad (6\text{-}4)$$

This carbonic acid causes a reduction in pH of the water which makes it quite corrosive to steel (API, 1958):

$$Fe^{o} + H_2CO_3 \longrightarrow H_2 + FeCO_3 \text{ (Iron Carbonate Corrosion Product)} \qquad (6\text{-}5)$$

The acidity of the solution, and therefore the corrosion rate, is influenced by the partial pressure of carbon dioxide. At higher pressures, more carbon dioxide will dissolve in water creating a stronger acid. If the partial pressure values are above 30 psi (2.1×10^5 N/m^2), the well stream is probably corrosive; 7 to 30 psi (4.8×10^4 to 2.1×10^5 N/m^2) may be corrosive, and 0 to 7 psi (0 to 4.8×10^4 N/m^2) is noncorrosive (API, 1958). In carbon-dioxide miscible injection, pressures rarely fall below 1200 psi (8.3×10^6 N/m^2) (Allen and Roberts, 1978).

The rate and amount of corrosion caused by dissolved carbon dioxide is also dependent upon the oxygen content, the salts dissolved in the water, the temperature, and the fluid velocities. Water that contains both dissolved oxygen and carbon dioxide is more corrosive to steel than water which contains only an equal concentration of one of these gases (Ostroff, 1965). In waters containing magnesium and calcium bicarbonates, increases in temperature can cause the evolution of carbon dioxide and result in increased corrosion. At the same time, carbonates of these salts can precipitate out on the metal surface, resulting in the formation of a protective coating, which may reduce corrosion rates. As with other types of corrosion, higher than normal fluid velocities can cause erosion of corrosion products that normally stifle the corrosion reaction, allowing corrosion to continue unabated.

Carbon-dioxide corrosion may appear as a uniformly thinned metal surface or as sharp, well-defined pits. Surfaces constantly bathed in a dissolved carbon-dioxide solution will tend to exhibit uniform thinning, whereas pitting is caused by carbon dioxide dissolved in droplets of water condensed on the injection-tubing wall (API, 1958).

6.1.3 Hydrogen-Sulfide Corrosion

Hydrogen sulfide gas dissolved in water, even in small amounts, can create a very corrosive environment (Allen and Roberts, 1978). Dissolved hydrogen sulfide forms a weak acid and in the absence of oxygen will attack iron and non-acid resistant alloys (Warner and Lehr, 1977); moreover, it becomes severely corrosive to acid-resistant alloys when oxygen is present. Hydrogen sulfide is often present in oil-field production brines that are subsequently

disposed by well injection. This practice has resulted in instances of severe corrosion in injection tubing, especially when the brines become contaminated with oxygen during surface handling (API, 1958). The general mechanism of this type of corrosion as it affects iron and steel is stated as follows (API, 1958):

$$Fe^{o} + H_2S \longrightarrow FeS_x \text{ (Iron Sulfides)} + H_2 \qquad (6\text{-}6)$$

Other metals react in essentially the same manner to produce metallic sulfides. The corrosion rate in water containing hydrogen sulfide is also influenced by the presence of dissolved salts and dissolved carbon dioxide (Ostroff, 1965); when these substances are present, hydrogen sulfide corrosion rates increase.

Hydrogen-sulfide corrosion of steel or iron results in the deposition of black scale (iron sulfide) on the metal surface. The scale tends to cause a local acceleration of corrosion because steel is anodic to the iron sulfide (Allen and Roberts, 1978). This reaction results in deep pits with underlying deep cracks in the metal. Cracking is due to embrittlement caused by atomic hydrogen formed in the corrosion process. Hydrogen diffuses into the steel where it reacts with itself to form molecular hydrogen. These larger molecules are trapped and cause the steel to split, blister, or crack. This damage may lead to stress fatigue of the material.

Microorganisms can contribute to corrosion caused by hydrogen sulfide attack. Sulfate-reducing bacteria are most important from a corrosion standpoint. Corrosion induced by such bacteria may be found in the internal portions of injection wells (such as in the casing/tubing annulus), as well as on the outside of injection casing.

Sulfate-reducing bacteria are anaerobic bacteria and grow under scale, debris, or other bacterial masses where oxygen cannot penetrate (Baumgartner, 1962). These bacteria reduce sulfate ions in water to hydrogen sulfide by using cathodic hydrogen. As the bacteria obtain hydrogen from the cathode (e.g., the metal surface of the casing) to support the reaction, the rate of corrosion is increased and ferrous sulfide corrosion products are created. The overall reaction takes the form (Ehrlich, 1972):

$$4Fe^{o} + H_2SO_4 + 2H_2O \longrightarrow FeS + 3Fe(OH)_2 \qquad (6\text{-}7)$$

6.1.4 Acid/Alkaline Corrosion

Direct contact between acids and injection-well tubing can cause many metal materials to dissolve. In fact, acidic wastes are often the cause of corrosion failure in injection systems (Warner and Lehr, 1977). The acid reacts with the metal causing ions to go into solution. A difference in electric potential is set up between two different areas on the metal. The rate of corrosion is a function of the strength of the acid and the metal involved. For example, copper has much less tendency to dissolve than iron or zinc (API, 1958). Stainless steel tubing provides corrosion resistance to some acids. Rubber and plastic-lined tubing are also suitable for resisting acid corrosion.

Highly alkaline solutions may also be corrosive. For example, at extremely high concentrations of sodium hydroxide, iron corrodes forming soluble sodium ferrite, $NaFeO_2$ (Ostroff, 1965). Carbon or stainless steel is preferred for tubing injecting highly alkaline fluids.

6.1.5 Galvanic Corrosion

Galvanic corrosion occurs where two different metals or alloys come into contact in the same environment. For example, using a stainless steel or K-Monel packer with a steel tubing may result in the corrosion of the tubing. This type of corrosion is distinguished from electrolytic corrosion in that the corrosion is a result of the difference in electrical potential between two dissimilar metals instead of two different areas on the surface of the same metal. Almost all metals have different solution potentials, so that when the two metals come together, the difference in potential results in current flow in the presence of an electrolyte.

The galvanic series for metals and alloys in sea water is shown in Table 6.1. Coupling an active metal (e.g. zinc) with a less active metal (e.g., stainless steel) will cause galvanic corrosion of the more active metal (Ostroff, 1965).

TABLE 6.1
GALVANIC SERIES FOR SELECT METALS IN SEA WATER
(Jellinek, 1958)

Active or Anodic End

- Zinc
- Alclad 3S
- Aluminum
- Low steel
- Alloy steel
- Cast iron
- Stainless steels (active)
  - Type 410
  - Type 430
  - Type 304
  - Type 316
- Ni-resist
- Muntz metal
- Yellow brass
- Admiralty brass
- Aluminum brass
- Red brass
- Copper
- Aluminum bronze
- Composition G bronze
- 90/10 Copper-nickel
- 70 + 30 Copper-nickel-low iron
- 70 + 30 Copper-nickel-high iron
- Nickel
- Inconel
- Stainless steels (passive)
  - Type 410
  - Type 430
  - Type 304
  - Type 316
- Monel
- Hastelloy C

Noble or Cathodic End

The corrosion rate increases when connected metals are more widely separated in the galvanic series. In addition, the corrosion rate per unit area of the corroding metal is almost proportional to the total area of the noncorroding metal (Allen and Roberts, 1978). Therefore, if the area of the active metal is very large compared to the area of the less active metal, corrosion will not be so severe.

6.1.6 Nonmetallic Corrosion

Nonmetallic materials used in injection wells are totally immune to corrosion by electrochemical and galvanic effects. However, plastic and fiberglass-reinforced casing and tubing and the rubber seal materials in packer mechanisms are susceptible to chemical attack by certain nonaqueous or organic solvents. Deterioration of these materials occurs by a process called solvation, which is the physical absorption of an organic solvent by the material. Common solvents include acetone, methyl ethyl ketone, toluene, trichloroethylene, turpentine, and xylene. The extent of chemical attack depends on the temperature and stress in the surrounding environment.

6.2 DETECTION AND MEASUREMENT OF CORROSION

Tubing and casing materials should be compatible with the injection operation, the fluid to be injected, and the environment in which the well is constructed. To determine the proper materials for construction, it may be desirable to measure the corrosiveness of the injection fluid in the laboratory. Despite the consideration the control of corrosion receives during the well design, there often is a need to recognize corrosive environments during well construction and to detect and measure corrosion in an operating injection well.

Before initiating a corrosion-prevention program it is necessary to determine if corrosion is present, the cause of corrosion, and the rate and severity of corrosion. The rate and effects of corrosion should be measured before and after application of prevention measures to determine the effectiveness of a corrosion-prevention program.

Several methods are available for the detection and the measurement of corrosion in injection wells including: weight-loss specimens, electrical resistance probes, electrochemical tests, caliper survey logs, electromagnetic logs of casing thickness, casing potential logs, and ultrasonic/radioactive logs. This section focuses primarily on the first three techniques. (More detailed discussion of logging methods to measure corrosion is provided in Chapter 7.)

6.2.1 Weight-Loss Specimens

The most common of all corrosion rate measurement tests involves exposing pieces of metal similar to those in the injection system to the corrosion environment. A small, metal coupon is exposed to well fluids for a defined period of time, then is removed, cleaned, and weighed to determine the amount of metal loss (Allen and Roberts, 1978). Down-hole coupon installation can be made by using standard wireline equipment. Corrosion rates are usually measured in mils per year (mpy) penetration or metal loss. A low corrosion rate may be serious if the pitting type of corrosion is occuring, whereas a high rate with a general area type of metal loss may be relatively insignificant.

The visual appearance of the coupon after exposure may indicate the type and cause of corrosion (Ostroff, 1965). For example, a black sulfide coating shows the presence of hydrogen sulfide in the system. Ferric oxide indicates oxygen is present, and carbon dioxide corrosion can be detected by ferrous carbonate deposits. An example of how a coupon test can be used to evaluate corrosion rates of various metals in a salt-water injection well where hydrogen sulfide containing brines are being disposed is provided in Table 6.2. It should be noted that the alloy compositions and the conditions of exposure are not comprehensive. Thus, with the exception of a few metals and alloys of changeless performance, any indicated usage should be correlated in detail with all related corrosion data.

At one time, coupons were widely used and considered to be the best method for estimating internal corrosion, especially in oil-field production and injection-well operations. The principle disadvantages of coupons concern

TABLE 6.2
CORROSION RATE OF METALS AND ALLOYS FOR
"SOUR" (HYDROGEN SULFIDE CONTAINING)
SALT WATER
(Gulf Oil Corporation, 1948)

Metal or Alloy	Corrosion rate* (Mils per year)
Nickel	1.0
K Monel	1.1
Nickel plated steel	2.8
Antimonial admiralty	3.2
Type 316 18-8 (Mo)	5.5
Aluminum 6061-T6	6.9
Type 304 18-8	10.2
Type 347 18-8 (Cb)	10.8
70-30 Copper Nickel (70% Cu, 30% Ni)	14.0
Carbon Steel J-55	15.6
Carbon Steel N-80	16.0
Alclad	16.2
Croloy 2-1/4	17.8
Galvanized steel	23.3
Croloy 5	23.4
9% Nickel	25.4
Copper Steel (0.26 Cu)	25.8
Yoloy (2 Ni, 1 Cu)	25.9
5% Nickel	27.3
12 Chrome cast	28.7
3% Nickel	29.0
0.40 Carbon cast	29.7
Croloy 9	30.1
Carbon Steel H-40	32.6
Crology 12	33.5
Corten (0.48 Ni, 1.04 Cr, 0.41 Cu)	35.6
Ampco Grade 8 (88 Cu, 10 Al, 1 Fe)	36.0
Cr-Mo-Si steel (2.09 Cr, 0.56 Mo, 1.17 Si)	38.1
Everdur 1010	62.2
Copper plated steel	64.6
Red brass alloy 24 (85 Cu, 15 Zn)	67.1
Copper	107.8

* Corrosion rates of insulated coupons 4.5 by 1.5 in. in SWD line, Darst Creek Field, Texas. 60 days exposure. Corrosion rates are average of 4 coupons. Salt water tests: pH-7; H_2S-200 mg/l; total solids-26,000 mg/l; temperature-120°F; velocity-2 ft/sec.

the time required to obtain results and that coupons show corrosion only at the point of their installation (Allen and Roberts, 1978).

6.2.2 Electrical-Resistance Probes

Electrical-resistance corrosion probes, which are based on an adaption of the Wheatstone bridge, measure changes in electrical resistance of a metal specimen as it corrodes (Ostroff, 1965). Probes are availale in a variety of sizes, thicknesses, metals, and alloys.

The probe, with its attendant portable instrument box, is call a Corrosometer. Several probes can be monitored at convenient time intervals with one instrument; this is particularly valuable when it is necessary to measure corrosion rates at different points within the system at the same time.

The Corrosometer has found its principle applications in injection systems involving gas streams because the probe does not have to be submerged in water to function. A disadvantage of the Corrosometer is that it is usually limited to the measurement of uniform corrosion. The Corrosometer can give misleading results if a deposit forms on a probe (Allen and Roberts, 1978). It also is a sensitive and delicate instrument not easily repaired, and it is difficult to operate by the untrained.

6.2.3 Electrochemical Tests

A corrosion-rate meter can be used to measure corrosion current and corrosion rate because metal loss is directly proportional to current flowing from the test electrode (Allen and Roberts, 1978). An instantaneous corrosion-rate meter has the capacity to detect very low rates of uniform corrosion and record data for multitest points on a continuous basis. Some progress has been made in using corrosion-rate meters to predict pitting-type corrosion.

The corrosion-rate meter is particularly useful to study the changes throughout an injection-well system caused by the introduction of corrosion inhibitors, air

leaks, or other changes. The test probes must be submerged in liquid and positioning must be done with care in a flowing stream to avoid shadowing one electrode by another (Allen and Roberts, 1978). The electrodes may experience short-circuiting resulting from corrosion products or solids in the injection fluid.

6.2.4 Well-Logging Methods

Caliper surveys, electromagnetic logs, casing potential logs, and ultrasonic/radioactive-measurement logs are techniques commonly used for evaluating active corrosion. Brief descriptions of these methods are provided below. (More complete discussions can be found in Chapter 7.)

Caliper surveys are run to inspect the internal surface of tubing or casing. Mechanical feelers contact the inside metal surface and will physically detect metal loss due to pitting and metal thinning. Caution should be exercised when running calipers through coated tubing to prevent pipe coating damage. In addition, caliper feelers may remove protective scales and allow corrosion to occur in the feeler tracks.

Casing-thickness logs can be developed by using an instrument which relies on an electromagnetic field to measure the thickness of metal at any point in the casing. This type of log can be used to calculate external metal loss when the loss of metal on the inside of the casing has been measured with an internal caliper.

Current flow in well casing can be measured with a logging tool with two sets of contactor knives. Polarity of the voltage reading between the two contacts indicates at any given point whether current is flowing from the casing to the earth or from the earth to the casing. Corrosion is indicated where current is leaving the pipe. A potential log is the best approach to find active corrosion on the outside of the casing and to show effectiveness of cathodic protection (Allen and Roberts, 1978).

Finally, ultrasonic or radioactive devices can be used to measure wall thickness and detect thinning of metal. Their principle limitations are that they may not detect small pits and that the measurement is made only at one point.

6.3 CORROSION CONTROL

Corrosion can be prevented or minimized by the application of a number of different design considerations and operating techniques which include: material used, protective coatings, preinjection treatment, chemical inhibitors, or cathodic protection. The original design concept can be chosen to reduce the severity of corrosion by the use of corroson-resistant tubing and casing materials. Provisions can be made during well design for the application of certain mitigative procedures; for example, the well could be designed to allow for application of corroson inhibitors to the casing/tubing annulus if the need arises during operation.

Metals resistant to corrosion are available for virtually all corrosive environments encountered in injection operations. The problem with many of these corrosion resistant metals (extreme examples of which are platinum and gold) is their cost. Iron and steel may corrode, but their lower cost, ease of fabrication, and strength have helped them become the most commonly used metals in injection operations (Allen and Roberts, 1978). There are other metals and alloys which cost slightly more than iron or steel but provide resistance to corrosion in specific applications.

The choice of metals to resist corrosion in a specific application is affected by the corrosive environment, as well as the physical requirements for the material. In a hydrogen sulfide environment, the effect of hydrogen embrittlement on strength and durability of a metal is the primary concern (Allen and Roberts, 1978). Low-carbon steels and other higher cost alloys are useful in preventing sulfide attack. High strength carbon steel is not recommended because of greater tendency toward sulfide cracking (API, 1958). For carbon dioxide and oxygen environments, where embrittlement is not a concern, metals should be selected based on control of metal loss. These metals are typically more expensive alloys, such as stainless steel and monels; consequently, economics might dictate that other methods of corrosion control be used. For corrosion resistance to most acids and alkalies, compatible stainless steel is usually employed for injection tubing strings. Tables of suitable metals and alloys for hydrogen sulfide, carbon dioxide, and oxygen corrosion are provided in Chapter 4.

Downhole applications of nonmetal, corrosion-resistant materials are limited to certain types of plastics. Other nonmetal materials, such as cement-asbestos and ceramics, do not possess the temperature resistance and strength properties necessary for injection tubing. The most extensively used plastic pipe and tubing is fiberglass pipe reinforced with epoxy resin (Donaldson, 1972). This material is highly resistant to corrosive fluids, and also affords relatively good resistance to corrosive attack by acids and alkalies (Ostroff, 1965). PVC and other plastic pipe also offer this corrosion-resistant capability, but have lower strength and temperature ratings than reinforced fiberglass materials. A disadvantage of epoxy-reinforced fiberglass and other plastic tubing materials is their relatively poor resistance to attack by organic solvents and dissolved chlorine.

6.3.1 Protective Coatings

Coatings prevent corrosion by removing or separating the corrosive environment from the metal. Paints, plastics, cement, rubber, and ceramics have been used to provide such barriers (Allen and Roberts, 1978). In addition, some metal coatings, like zinc on steel, cathodically protect the base metals.

Organic, inorganic, or metallic coatings are selected on the basis of temperature, pressure, and the corrosiveness of the environment. A major problem with protective coatings is that a break in the coating which exposes the base metal causes serious corrosion (Ostroff, 1965).

Considerable use has been made of organic coatings for protection against the interior corrosion of tubing in wells handling brine (API, 1958). Organic coatings include paint (which are applied as thin films), plastic (baked phenolics, PVC, polyurethane), and heavier bituminous coating (coal-tar enamels). Surface preparation and proper application is very important in the success of the coatings.

Inorganic cement linings are also used extensively for tubing in wells handling brines (API, 1958; Allen and Roberts, 1978). Cement linings are not recommended for use with highly acidic solutions. Moreover, cement linings are permeable to water and corrosion products tend to form

between the lining and the subsurface metal. This buildup of corrosion products can eventually lead to the cracking and the sloughing of the lining (API, 1958).

For corrosion control in injection-well operations, the only metallic coatings of importance are zinc and aluminum on steel (Allen and Roberts, 1978). They may be used on buried steel components where oxygen corrosion is moderate, but their best application is for atmospheric exposure of surface equipment (Allen and Roberts, 1978).

6.3.2 Preinjection Treatment

Frequently, the removal of corrosive agents from injection fluid by preinjection treatment methods can be the best means of corrosion control. The most common, preinjection treatment used involves degasification and/or neutralization.

Degasification

Degasification involves the complete removal of corrosive dissolved gases from water. The most common method of degasifying water in preinjection treatment is to selectively remove dissolved oxygen, since prevention of corrosion due to acid gases, carbon dioxide and hydrogen sulfide, is usually cheaper than gas removal (Allen and Roberts, 1978). Oxygen degasification can be accomplished by chemical scavengers, vacuum deaeration, or counter-flow gas stripping.

Chemical scavengers for oxygen removal are based on a chemical reaction between oxygen and another chemical. A commonly used chemical is sodium sulfite which is particularly useful for removing small amounts of oxygen from large volumes of water. Dissolved oxygen is removed in the oxidation of sulfite to sulfate:

$$Na_2SO_3 + 1/2\ O_2 \longrightarrow Na_2SO_4 \qquad (6\text{-}8)$$

In practice, 10 ppm of sodium sulfite are used to remove 1 ppm of dissolved oxygen (Ostroff, 1965). Catalysts,

such as cobalt chloride, are used to increase the rate of the reaction. The presence of hydrogen sulfide in the water reduces the effectiveness of sodium sulfite to scavenge oxygen. Sulfate-reducing bacteria should also be prevented from growing in water-handling systems in which sulfite is used to scavenge oxygen.

The sulfite ion can also be formed in water by adding sulfur dioxide gas. Sulfur dioxide can be added from bottled liquid containers or on-site gas generators. Bottled liquid is economical for treating small systems with low oxygen concentrations. The use of sulfur dioxide for oxygen removal has the potential disadvantage of producing corrosive acids in solution and also of creating barium or calcium scales that may plug the injection formation.

Oxygen can be removed from water by running it through a vacuum in a packed tower. The low pressure and the small amount of oxygen in vapor contacting the water causes the dissolved oxygen to bubble out of solution (Allen and Roberts, 1978). The vacuum can be produced by pumps or steam injectors. Several passes through the vacuum deaeration column are necessary to reduce oxygen to less than 0.1 ppm (Allen and Roberts, 1978). Any free carbon dioxide will also be removed, which may result in scale deposition from the accompanying pH change. If further oxygen reduction is needed, chemical scavengers can be added after vacuum deaeration. Vacuum deaeration is applicable where chemical treatment is uneconomical, or where the addition of scavengers would form barium or calcium scale.

A counter-flow gas stripping column can be used to cause dissolved oxygen to escape from water to a natural gas stream. Either a packed column or a tray-type column can be used, although the tray-type is preferred (Allen and Roberts, 1978). Efficient removal of oxygen has been reported for a vacuum deaeration system supplemented by hydrocarbon gas stripping (Frank, 1972). Oxygen was reduced from 4.7 ppm to 0.05 ppm which reduced the corrosion of steel by almost 90 percent.

Injection-Fluid Neutralization

Neutralization of an acidic or basic fluid prior to injection can be an effective way to control corrosion.

Common chemicals that may be considered for neutralization are listed in Table 6.3. A potential problem with adding chemicals to neutralize pH is that insoluble precipitates may form, and these solids can cause the physical plugging of the injection zone. Recommended dosage rates for acid and alkali neutralization are shown in Table 6.4.

Caustic soda, although the most expensive of the alkali sources for acid neutralization, is usually preferred because it reacts instantaneously and creates less sludge. For neutralizing alkalies, sulfuric acid is most often used (Warner and Lehr, 1977).

6.3.3 Chemical Inhibitors

The addition of chemical inhibitors may be a simple and inexpensive means of reducing corrosion in tubing, well casing, and ancillary equipment. It must be stressed, however, that addition of chemical inhibitors is a supplement to other measures such as equipment selection or preinjection treatment.

There are two major groups of chemical inhibitors. The first group includes a wide variety of inorganic and organic compounds that are used to chemically or physically inhibit the corrosion reaction. The second group are bactericides used to kill microorganisms, like sulfate-reducing bacteria which contribute to corrosion.

Corrosion Inhibitors

The conditions of the environment and type of corrosion govern the choice of corrosion inhibitor (Ostroff, 1965). Usually, the choice of inhibitor is based on the experience of the corrosion engineer along with trial and error testing. Some typical corrosion inhibitors are shown in Table 6.5. Generally, organic inhibitors form films on the metal surface, protecting the metal from attack. Some of the inorganic compounds, like the chromates, are anodic inhibitors (Ostroff, 1965). Many of these organic and inorganic inhibitors are considered toxic substances, and therefore must be used with caution to prevent contamination of potential potable water sources.

TABLE 6.3
COMMON CHEMICALS USED FOR
INJECTION FLUID NEUTRALIZATION
(Warner and Lehr, 1977)

Injection-Fluid Characteristic	Neutralizing Chemical
Acid	Lime slurries Limestone Soda Ash Caustic Soda Ammonia Waste Alkali
Alkaline	Sulfuric Acid Hydrochloric Acid Carbon Dioxide Flue Gas Sulfur Waste Acid

TABLE 6.4
ALKALI AND ACID REQUIREMENTS FOR pH NEUTRALIZATION
(Warner and Lehr, 1977)

Alkali	Approx. Dosage (lb/lb H_2SO_4)	Acid	Approx. Dosage (lb/lb $CaCO_3$)
Dolomitic Limestone	0.95	H_2SO_4, 66°Be	1.0
High Calcium Limestone	1.06	HCl, 20°Be	2.0
Dolomite Lime, Unslaked	0.53	Flue Gas, 15% CO_2	3.0
High Calcium Limestone, Unslaked	0.60	Sulfur*	0.3
Dolomitic Lime, Hydrated	0.65		
High Calcium Lime, Hydrated	0.80		
Anhydrous Ammonia	0.35		
Soda Ash	1.10		
Caustic Soda	0.80		

* Would produce a reducing condition which might require additional treatment to produce an oxygen-containing effluent.

TABLE 6.5
CORROSION INHIBITORS
(Gatos, 1956)

Inhibitor	Approximate Concentrations (percent)	Corrosion Environment	Metallic System
INORGANIC			
Calgon	Small amount	Water systems	Steel
Disodium hydrogen phosphate	0.5	Citric acid	Steel
Potassium dichromate	0.05-0.2	Tap water, 68-194°F	Iron-brass
Potassium dihydrogen phosphate + sodium nitrate	small amount +5	Sea water	Steel
Potassium permanganate	0.1	0.3N NaOh solution	Aluminum
Sodium benzoate	0.5	0.03% NaCl solution	Mild steel
Sodium carbonate	Small amount	Gas condensate wells	Iron
Sodium chromate	0.07	$CaCl_2$ brine	Cu, brass
Sodium dichromate + sodium nitrate	0.1 + 0.05	Water	Heat-exchange devices
Sodium metaphosphate	Small amount	Ammonia	Mild steel condensers
Sodium nitrite	0.005	Water	Mild steel
Sodium orthophosphate	1	Water, pH = 7.25	Iron
Sodium silicate	0.01	Oil field brine	Steel pipe
ORGANIC			
Formaldehyde	Small amount	Oil wells	Oil well equipment
Erthritol	Small amount	K_2SO_4 solutions	Mild steel
Ethylaniline	0.5	HCl solutions	Ferrous metals
Mercaptobenzothiazole	1	HCl solutions	Iron and steel
Oleic acid	Small amount	Polyhydric alcohols	Iron
Phenyl acridine	0.5	H_2SO_4 solutions	Iron
Pyridine + phenyl-hydrazine	0.5 + 0.5	HCl solutions	Ferrous metals
Quinoline ethiodide	0.1	1N H_2SO_4	Steel
Rosin amine-ethylene oxide	0.2	HCl solutions	Mild steel
Tetramethylammonium	0.5	Aqueous solutions of organic solvents	Iron and steel
Thiourea	1	Acids	Iron and steel

The simple addition of corrosion inhibitors alone may not be sufficient to solve all corrosion problems. Corrosion caused by oxygen associated with salts cannot be effectively treated with inhibitors (API, 1958) and for these systems it may be necessary to remove the oxygen as well.

Inhibitors are added to the well tubing as well as to the casing tubing annulus. There are several methods available for adding corrosion inhibitors during well operation. One method involves filling the annulus during well completion with a solution containing either an oil- or water-soluble corrosion inhibitor (Donaldson, 1972). Inhibitors can also be slug injected while operations are shut down for a short time. Inhibitors can also be placed in fluid circulated above the cement in the casing-borehole annulus.

Bactericides

To prevent the growth of microorganisms which can contribute to corrosion, bactericides can be employed. Some inorganic chemicals are used as bactericides, such as chlorine, chromates, and compounds of mercury or silver. However, most currently used bactericides are organic chemicals (Warner and Lehr, 1977). Some typical chemical compounds used as bactericides are shown in Table 6.6.

Bactericides may be added by continuous feed or slug treatment. Service companies that supply bactericides for oil-field use should be consulted when selecting a preparation for microbial control in an injection well.

It should be noted that many bactericides exhibit varying amounts of toxicity to humans, and thus, injection of these substances into underground formations should be practiced in such a way to prevent contamination of potential sources of drinking water.

6.3.4 Cathodic Protection

Cathodic protection consists of applying an electric current to the surface of the protected metal to overpower

TABLE 6.6
CHEMICALS USED AS BACTERICIDES
(Ostroff, 1965)

Type of Bactericide	Example Compound	Physical Form	Concentration Range (ppm)
Chromium	Sodium chromate	Solid	500
Mercury	Mercuric chloride	Solid	50 - 300
Silver	Silver nitrate	Solid	0.05
Amine	Coco primary amine acetate	Solid	10 - 40
Diamine	Coco trimethylene diamine	Liquid	5 - 25
Quaternary Ammonium	Alkyl trimethyl quaternary ammonium chloride	Liquid	25 - 100
Chlorinated Phenols	Sodium tetrachlorphenate	Solid	12 - 50
Aldehydes	Gluteraldehyde	Liquid	20 - 75
Mercurials	Methyl mercuric acetate	Solid	250
Peroxygens	Peracetic acid	Liquid	10

the voltage of the corrosion cell and to prevent the resulting discharge of electrical currents from the metal into the ground. The result is that all areas of the metal become cathodic and corrosion stops. All previously anodic areas are suppressed as long as adequate current is applied. In injection-well operations, cathodic protection is used primarily for the external protection of well casings. It is typically applied to supplement other corrosion prevention techniques, such as cementing casing through potentially corrosive salt-water zones.

Cathodic protection requires a direct current which may be generated by using an external source of alternating current and a rectifier for converting to direct current. On-site thermoelectric generators may also be used to directly produce direct current. Current is discharged into the soil from a group of anodes called a ground bed. Required current will vary from 1-1/2 amperes for 1500 feet (457 m) of 6 inch (15.2 cm) casing to as much as 20 amperes for multicased, deep wells. The voltage can usually be adjusted as required from 6 to about 24 volts, depending on the needed current and the resistance of the ground bed (Allen and Roberts, 1978).

The ground bed can be installed so that there is a minimum electrical resistance between the anode and the surrounding soil (API, 1958). To optimize current distribution on the casing, the ground bed can be placed about 100 feet (30.5 m) from the wellhead and moved as far as possible from other pipe lines. Where possible, placement of the ground bed in areas of low soil resistance is desirable; a low-resistance material is usually packed around the anodes to serve as backfill.

Figure 6.1 depicts a typical cathodic protection installation for a well casing. A horizontal ground bed is shown. Vertically oriented ground beds, called anode wells, are also used to protect injection wells. These anode wells, which are drilled to about 300 feet (91.4 m), provide better vertical distribution of current, and less power is required than horizontal ground beds (Allen and Roberts, 1978).

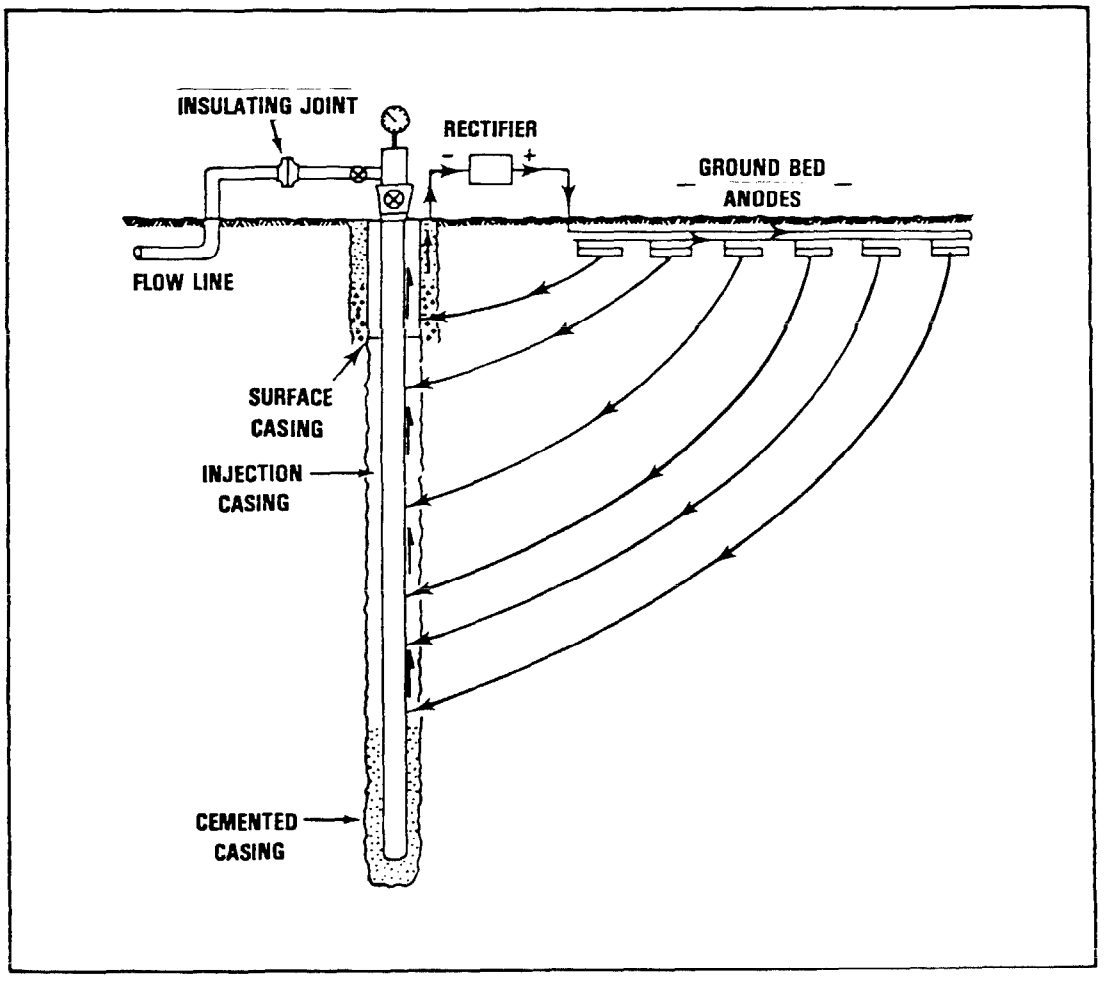

Figure 6.1. Example of cathodic protection scheme for well casing (Allen and Roberts, 1978)

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7. FORMATION AND WELL EVALUATION AND TESTING

A variety of techniques and procedures are available to evaluate formation conditions and injection-well design and construction. These techniques include formation and fluid sampling, geophysical logging, and various pressure evaluation procedures such as drill-stem testing and injectivity testing. The principles and applications of these techniques are discussed in the following chapter.

7.1 FORMATION AND FLUID SAMPLING

Drilling a borehole offers an excellent opportunity to collect data relevant to a number of important parameters of the formations penetrated. Procedures utilized may include sampling cuttings produced during drilling or obtaining larger intact samples through coring. Formation-fluid samples may also be collected.

7.1.1 Sampling and Analysis of Drill Cuttings

Cable-tool and rotary drilling techniques (see Chapter 3) produce cuttings which can be collected and analyzed. Cuttings produced during cable-tool drilling accumulate in the hole and are removed at intervals, [generally every five to ten feet (1.5 to 3.0 m)] by bailing. The cuttings obtained provide samples representative of the formation penetrated.

Cuttings produced during rotary drilling are carried to the surface by the drilling fluid. Cuttings are separated from the drilling fluid by diverting the stream through a sieve or into a shale shaker. It is possible to separate large fragments by this method; however, it may not be possible to separate much of the finer material such as clay. Care must be taken to identify the depth from which the sample is produced. Cuttings arriving at the surface do not represent the rock being cut at the time they are taken from the mud. Estimates of the lag time required for cuttings to come to the surface must be made to determine the depth at which samples have been produced and can be made by knowing the size of the borehole and the pumping

rate. Fragments produced during rotary drilling do not all rise with the drilling fluid at the same rate, and samples taken at one point in time may contain fragments produced over a range of depths. This problem can be minimized by observing penetration rates and by taking samples only after stopping drilling and cleaning the borehole by circulating drilling fluid for a period of time.

Cuttings are normally examined at the site under low-power magnification to identify rock type, grain size, color, and mineralogy. Testing the samples with acid can be used to determine carbonate material. More detailed discussions on sampling and analysis of drill cuttings are available in many petroleum geology and drilling textbooks ie, Dickey, 1979; Moore, 1974.

7.1.2 Coring

Geologic cores taken while drilling provide lithologic and hydrologic information superior to that obtained from the analysis of drill cuttings. However, coring is an expensive procedure and is employed only when drilling formations of special interest. Coring is accomplished through the use of a special drilling bit and a coring barrel which is attached to the end of the drill pipe. As the bit cuts into the rock, an inner core is left intact and pushed into the core barrel. The length of the core is limited by the length of the core barrel, a maximum of 90 feet (27.4 m). Obtaining intact cores from unconsolidated or partly cemented materials is difficult and frequently requires special equipment, such as rubber sleeve retainers. Cores are commonly 3.5 inches (8.9 cm) in diameter, but can range between 1 and 5 inches (2.54 and 12.7 cm).

Techniques are also available to take cores from the sides of a borehole after drilling is completed. These sidewall cores are generally taken to provide information about formations from which cores were not taken during drilling. Sidewall coring is accomplished by running a wireline coring device which contains hollow cylinders. These hollow cylinders are driven into the formation by an explosive charge. The cores are relatively small, ranging between 7/8 and 1-3/4 inches (2.22 and 4.4 cm) in diameter and between 1 and 1-3/4 inches (2.54 and 4.4 cm) in

length. Sidewall coring is limited to rather soft materials.

Examination of conventional cores can provide substantial amounts of data valuable to the design and the construction of injection wells. Visual examination of cores can reveal fractures, bedding features, and solution cavities; laboratory examination can determine porosity, grain size, permeability, and formation-fluid quality. The application of data taken from conventional cores is limited by a number of factors. For example, cores may be affected by drilling fluids. Cores which have been taken at depth may have been subjected to considerable pressure, and measurements made in an unpressurized environment may not reflect the in-situ characteristics of the material.

Data obtained from sidewall cores are not as reliable as that obtained from conventional cores due partly to the relatively small size of the sample. Formations are disturbed substantially during coring, and the more permeable formations sampled have generally been invaded with drilling fluid. Consequently, sidewall cores are not used extensively for directly evaluating porosity, permeability, or saturation characteristics of rock. They do provide valuable data, however, on grain size and rock type (Anderson, 1975; API 1960).

Expense and inherent limitations prohibit the use of coring programs solely to determine formation characteristics. Instead, they are used with other evaluation techniques including geophysical logging, drill-stem tests, and pressure tests. The particular value of cores lies with the data made available for use in cross-referencing with other evaluation techniques (Wilson and Hensel, 1978; Shirer, et al., 1978; Collins, 1976). Coring programs can be of particular value in injection-well design by providing a sample of the injection zone for testing to determine waste and formation compatibility (Donaldson, 1972; Hewitt, 1963; Keelan and Koepf, 1977).

7.1.3 Fluid Sampling

Formation-fluid samples can be obtained by a number of methods, including bailing, drill-stem testing, swabbing, and air-lift methods. In holes drilled by cable-tool methods,

bailing may be used to obtain formation water samples but care must be taken to insure that the water sample taken is representative of the formation of interest and not of another formation also draining into the borehole. This problem is reduced in holes in which casing is driven since the casing acts to isolate the lowest formation from the other water-producing formations.

Drill-stem testing methods can be used to obtain fluid samples in uncased holes. Single or double packer arrangements are used to isolate the zone from which the fluid is sampled. Wireline devices utilize principles similar to drill-stem testing and are also used to obtain fluid samples. The usefulness of formation-fluid samples obtained by drill-stem or wireline procedures is limited by the extent to which they are contaminated by drilling fluid.

Swabbing is a method for obtaining fluid samples from cased holes. A swab is seated against the casing. When the swab is pulled upward, fluid is drawn to the surface (API, 1966).

7.2 GEOPHYSICAL LOGGING

Geophysical logging is a generic term applied to a variety of techniques by which formation and well-construction characteristics can be evaluated through the interpretation of specific physical measurements made within the borehole. These measurements are made by a logging tool which provides a continuous measurement of the selected physical parameter during the ascent (or descent) of the tool from the borehole. These measurements are electrically transmitted to the surface where they are recorded. The physical measurements generally are not direct measurements of the geologic or hydraulic parameter of interest but are measurements of related physical characteristics which can be interpreted to provide an evaluation of the desired parameter.

During injection-well construction, geophysical logging can be used to evaluate a number of important formation characteristics. Logging is commonly used for lithologic and stratigraphic identification and for the correlation of formations encountered with formations known to exist. Logging can also be used to measure formation porosity and

to help identify the nature and extent of fractures. Permeability can be qualitatively determined from logging. Techniques are available for quantitative determination of permeability but are subject to numerous limitations which make the quantification of permeability more feasible using nonlogging methods. Although subject to a number of constraints, logging may also be used to determine formation-water quality. In addition, logging can be used to determine a number of well-construction features such as the nature and the extent of cement bond, fluid flow behind the casing, and the condition of the casing.

A large number of logging techniques are available for use in the evaluation of formation and well parameters. Table 7.1 summarizes many of these techniques according to the actual physical parameter measured and its potential applications. Each of the major logging companies offers many of these techniques under a variety of trade names. A categorization of the techniques according to the trade names used by major service companies is presented in Table 7.2.

A combination of logs is generally used within a single borehole to evaluate many formation characteristics as well as to evaluate a single parameter. The choice of logs comprising a particular logging suite depends on local lithology, data requirements, and availability of specific logging tools. The specification can be allowed considerable flexibility since a variety of tools can accomplish similar goals. Many of the parameters can be measured using other techniques which may offer a more meaningful evaluation or a less expensive approach.

The following section discusses the principles and applications of many of the logging techniques available for use at injection-well sites. The section is concluded with a discussion concerning the formulation of suites of logs to meet many of the requirements for formation and well-construction evaluation. For a detailed discussion of logging principles and applications, a variety of additional resources are available. The major service companies offer texts discussing the principles and applications of their services (Schlumberger, 1972 and 1974; Welex, n.d.). In addition, a variety of textbooks on the subject are available (Wyllie, 1963; Pirson, 1970; Merkee, 1979; Petroleum Extension Service, 1971). Numerous articles concerning individual techniques are also available. An effort has

TABLE 7.1
GEOPYSICAL WELL LOGGING METHODS AND
THEIR APPLICATIONS
(Modified from Warner and Lehr, 1977)

Method	Property	Application
ELECTRICAL		
Spontaneous Potential (SP)	Electrochemical and electrokinetic potentials	Formation-water resistivity; shales, and nonshales; bed thickness; shaliness
Nonfocused Electric Log	Resistivity	a. Water and gas/oil saturation. b. Porosity of water zones. c. Formation-water resistivity in zones of known porosity. d. True resistivity of formation. e. Resistivity of invaded zone.
Focused Induction Log	Resistivity	a,b,c,d. Very good for estimating formation resistivity in either fresh water, oil base muds, or air filled holes.
Focused Resistivity Logs	Resistivity	a,b,c,d. Especially good for determining formation resistivity of thin beds.
Focused and Nonfocused Microresistivity Logs	Resistivity	Resistivity close to the borehole for calculating porosity. Bed thickness.

TABLE 7.1 (Cont'd)

Method	Property	Application
ACOUSTICAL		
Transmission (sonic velocity and amplitude logs	Compressional and shear wave velocities	Porosity; lithology; elastic properties, bulk and pore compressibilities.
	Compressional and wave attenuations	Location of fractures; cement-bond quality.
Reflection	Amplitude of reflected waves	Location of vugs, fractures; orientation of fractures and bed boundaries; casing inspection.
RADIATION		
Gamma Ray	Natural radioactivity	Shales and nonshales; shaliness.
Spectral Gamma Ray	Natural radioactivity	Lithologic identification.
Gamma-Gamma	Bulk density	Porosity; lithology.
Neutron-Gamma	Hydrogen content	Porosity
Neutron-Thermal Neutron	Hydrogen content	Porosity; gas from liquid.
Neutron-Epithermal Neutron	Hydrogen content	Porosity; gas from liquid

TABLE 7.1 (Cont'd)

Method	Property	Application
RADIATION (cont'd)		
Pulsed Neutron Capture	Decay rate of thermal neutrons	Water and gas/oil saturations; re-evaluation of old wells.
Spectral Neutron	Induced gamma ray spectra	Location of hydrocarbons; lithology.
Radioactive Tracer Logging	Injected radioactivity	Leakage, flow behind casing.
OTHER		
Nuclear Magnetism	Amount of free hydrogen; relaxation rate of hydrogen	Effective porosity and permeability of sands; porosity for carbonates
Temperature Log	Temperature	Formation temperature.
Noise	Sound	Flow behind casing.
Casing Inspection	Electro-magnetic properties	Well condition.
Caliper	Borehole Well position	Borehole diameter; well condition.

TABLE 7.2
SOME GEOPHYSICAL WELL LOGGING SERVICES AVAILABLE
FROM THREE COMPANIES PROVIDING WELL LOGGING SERVICES
(Warner and Lehr, 1977)

COMPANY		
Welex	Schlumberger	Dresser-Atlas
Electric Log	Electrical Log	Electrolog
Induction Electric Log	Induction Electrical Log	Induction Electrolog
Dual Induction Guard Log	Dual Induction Laterolog	Dual Induction Focused Log
Guard Log	Dual Laterolog	Laterolog
Contact Log	Microlog	Minilog
FoRxo Log	Microlaterolog	Micro-Laterolog
-	Proximity Log	Proximity Log
Acoustic Velocity Log	Sonic Log	Acoustilog
Compensated Acoustic Velocity Log	BHC Sonic Log	BHC Acoustilog
Fracture Finder Log	Amplitude Log	Fraclog
Micro-Seismogram Log	Variable Density Log	Variable Amplitude Density Log
Density Log	Formation Density Log	Densilog
Compensated Density Log	Compensated Formation Density Log	Compensated Densilog
Simultaneous Gamma Ray-Neutron Log	Gamma Ray-Neutron Log	Gamma Ray-Neutron Log
Side Wall Neutron Log	SNP Neutron Log	Epithermal Sidewall Neutron Log

been made to include a number of these citations in the following discussions.

7.2.1 Electric Logging

Electric logs were one of the first geophysical-logging techniques developed and applied to determine characteristics of geologic formations. Among the most commonly applied techniques, electric logging is based on measuring natural electric potential or resistivity and, accordingly, is classified as spontaneous potential logging and resistivity logging.

Spontaneous Potential Logging

The spontaneous potential log, also known as self potential or SP log, is used to correlate stratigraphy, provide a qualitative indication of the amount of clay or shale present, identify permeable beds, and indicate formation-water resistivity (Doll, 1949; Wyllie, 1948; Alger, 1971). The SP log measures the natural electric potential established between the borehole fluid and the formation fluid with relationship to a fixed potential electrode located at the surface. The relative potentials observed are dependent on formation lithology, and borehole and formation-fluid characteristics.

While a variety of phenomena are involved in producing the potentials oberved in SP logging, electrochemical potentials are generally considered most important. These potentials result from differences in ionic concentrations (salinities) between the borehole fluid and the formation fluid. When fluids of different ionic concentrations are placed next to each other, ions will migrate from the fluid of high concentration to the fluid of low concentration. Generally negative ions have a higher mobility and their migration results in the development of a positive potential in the fluid of higher concentration. However, if materials such as clay or shale are present, a second phenomenon influences the potentials developed between the borehole fluid and the formation fluid. Clay materials act as ion-selective membranes which preferentially allow cations

(positive ions) to migrate. Clay consequently acts to reverse the normal trend and to allow more cations to migrate from the higher salinity fluid into the lower salinity fluid. Thus, in the case in which formation fluid is more saline than borehole fluid, the SP logging will produce the greatest positive measurement as the probe passes clay beds and progressively more negative measurements as clay content decreases.

A schematic diagram of an SP log is shown in Figure 7.1. The maximum positive deflection reflects potentials developed next to a clay or shale and is known as the shale baseline. Similarly sands reproduce more negative readings with a clean sand, yielding a maximum negative reading identified as the sand baseline. However, any shift in concentration differences between formation and borehole fluids will affect the shape of the SP curve since ion migration and, therefore, observed potentials are proportional to the relative difference between the salinities of the two fluids. In addition, an inversion in the curves will result if formation fluids are less saline than borehole fluids.

As Figure 7.1 shows, SP logs can be used to identify clay beds and give an indication of the relative amount of clay present in sand and sandstone layers. By determining relative clay content, SP logs can help to qualitatively identify permeable beds. These logs also indicate the relative thickness of beds and can be used to correlate formations encountered during drilling with local stratigraphy.

Since the magnitude of deflections observed during SP logging is proportional to the ratio of formation-fluid and borehole-fluid ionic concentration, estimates of formation-water quality can, in some instances, be determined. Equations are available which relate the resistivity of the two fluids to the observed SP deflection; and if drilling fluid resistivity is known, formation-fluid resistivity can be calculated. These calculations yield fluid resistivity which can be used only to determine ionic concentration if the relative proportions of specific ions are known.

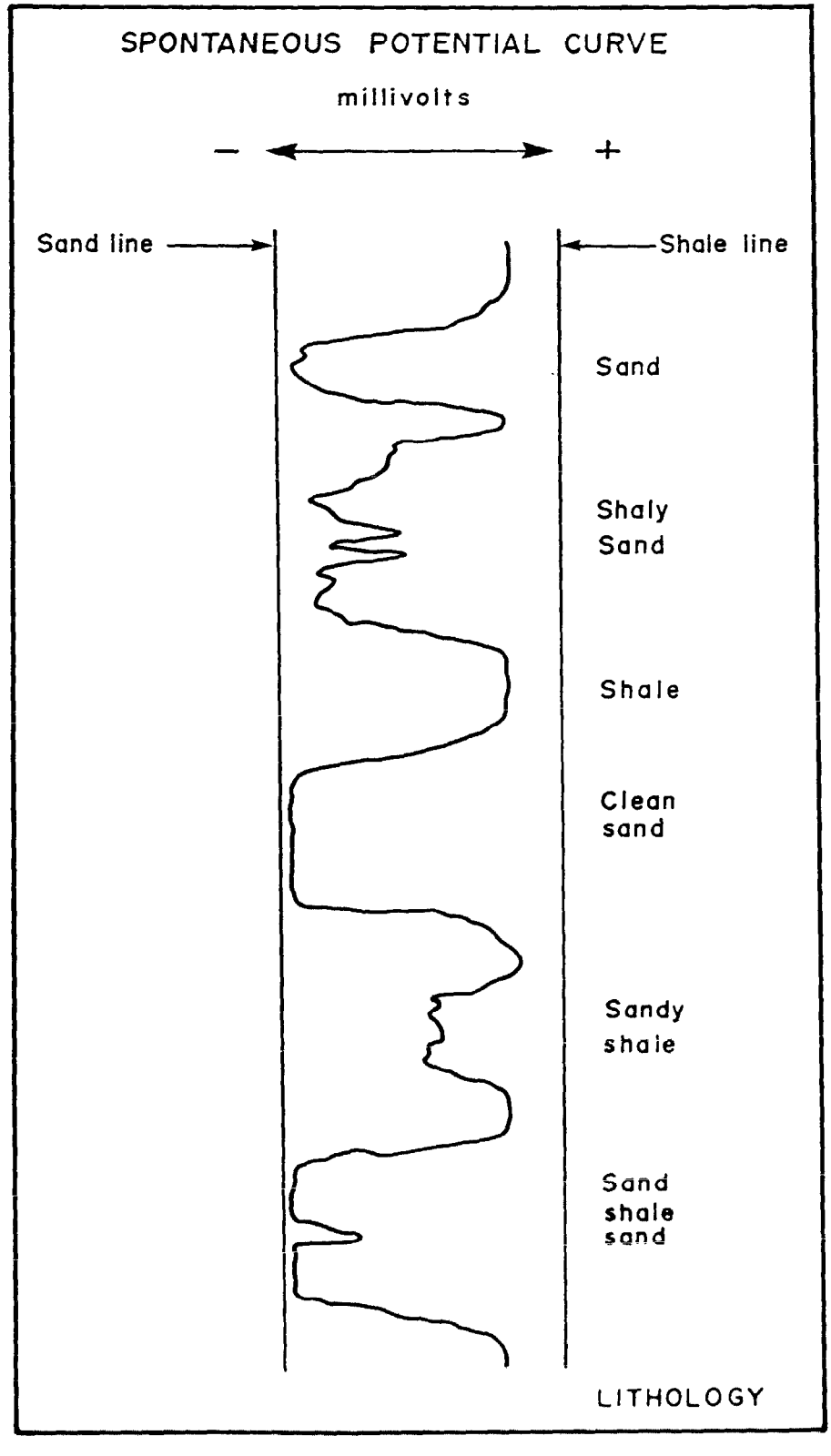

Figure 7.1. Schematic diagram of spontaneous potential log showing lithologic correlations

Resistivity Logging

Resistivity logging is one of the most commonly applied logging techniques used for stratigraphic correlation, formation-fluid resistivity measurements, porosity and fracture determination, pore pressures identification, and permeable beds identification. Resistivity logging provides a measurement of the ability of a formation to impede the flow of electricity and is inversely related to electrical conductivity. Formation resistivity is related both to formation lithology and to fluid content. In most cases, geologic materials are poor conductors of electricity, and thus the ability of a formation to conduct electricity is primarily a function of the relative amount and ionic content of fluids present in the formation. However, in formations in which metallic ores or clays with exchangeable ions occur or in which fluid content or ionic concentration is low, formation materials may also contribute substantially to the conduction of electrical currents.

It is common practice to relate formation resistivity to formation-fluid resistivity using a formation factor which is the ratio of formation resistivity to the fluid resistivity when 100 percent saturated with water (Archie, 1942). The formation factor for nonconductive geologic materials has been shown to be primarily a function of formation porosity, except in cases in which water conductivity is low. The relationship between observed formation resistivity, fluid resistivity, and formation factor or porosity is responsible for a number of potential applications of resistivity logging. If formation-resistivity measurements and a value for the formation factor are available, formation-fluid resistivity can be calculated to indicate water quality at injection-well sites. However, water resistivity cannot be translated directly into a total dissolved solids determination unless the relative proportion of each ionic species is known. The application of resistivity techniques for determining water quality for low conductivity/high quality ground water is tenuous because in such circumstances formation factors are dependent on both porosity and water quality.

Measurements of resistivity can be similarly applied to estimate porosity. If formation-fluid resistivity is

known, measurements of formation resistivity can be used to calculate the formation factor (which can be used to calculate porosity if sufficient information is available concerning lithologic characteristics of the formation). This application is subject to the previously discussed limitations concerning the altered relationship between porosity and the formation factor in formations containing high quality water. Resistivity logging is not widely applied to porosity determinations because a number of superior logging methods are available.

A variety of different resistivity logging tools are in use, but most are based on similar principles and procedures. Electrodes are used to establish a fixed current in the materials in and near the borehole, and potential electrodes are utilized to measure potential differences along the flow path of the induced electric current. Ohm's law is used to calculate resistivity from these measurements. The tools provide a continuous measurement of resistivity which is recorded at the surface as the tool is pulled from the hole. The observed resistivity reflects the changes in lithology and fluid salinity which occur within the borehole.

The first resistivity devices to be developed and used extensively were the point, the normal, and the lateral resistivity tools. These tools utilize different spacings between current electrodes to alter the radius of investigation. Generally, the larger the spacing between electrodes, the larger is the radius of investigation. Though a variety of spacings have been used, a number of standard spacings are common. The single point tool utilizes only a single electrode so no spacing distance is involved. The normal resistivity tools utilize either a 16 inch (40.6 cm) short or a 64-inch (162.6 cm) long electrode spacing. The spacing utilized most commonly in lateral devices is 18.67 feet (5.7 m).

Normal and lateral devices have a number of inherent disadvantages. Most importantly, as the electrode spacing is increased and the radius of investigation correspondingly increased, the ability to detect and to measure resistivities in thin beds is lost. This progressive loss of vertical resolution in normal and lateral devices as the depth of investigation increases led to the development of resistivity devices which focus current beams transmitted through the formation to increase the depth of investigation

while maintaining a high degree of vertical resolution. These focused resistivity tools have now nearly replaced the normal and lateral resistivity devices. The two basic focused-resistivity tools are the guard-log devices and the laterolog system (Doll, 1971a).

Another general type of resistivity device is the induction logging device which electromagnetically induces a current in the formation (Doll, 1949). The device is instrumented to measure the strength of the electromagnetic field resulting from the induced current. Since the induced current is directly related to formation conductivity these devices are commonly referred to as conductivity tools. Induction logging devices are particularly useful in boreholes containing nonconductive drilling fluid since they do not depend on electrical contact with the formation through fluids in the borehole.

Special resistivity tools include the microresistivity tools. These tools are only adaptations of the other basic resistivity techniques, and are the micro-normal, the micro-lateral, and the focused micro-logs. These tools have been developed to investigate conditions at the immediate periphery of the borehole and are frequently referred to as wall-resistivity tools.

Resistivity measurements made during logging are influenced by the true formation resistivity, materials within the borehole, and the diameter of the borehole. Most resistivity logs must be run in boreholes which contain a sufficiently conductive fluid to ensure electrical contact between the electrodes and the surrounding formation materials. However, if the fluids are too conductive, the electrical currents induced by the resistivity tool may follow a path within the borehole rather than through the formation and thereby yield anomalous formation resistivity readings. Increases in borehole diameter generally accentuate such problems.

The drilling process can produce changes within the formation that can profoundly affect resistivity measurements. Drilling fluids have a tendency to penetrate permeable formations, resulting in the formation of wallcake and a zone of invasion within the formation containing drilling-fluid filtrate (see Chapter 3). This creates a number of zones which exhibit different formation resistivities and may result in inaccurate interpretations of formation and fluid characteristics, if not accounted for.

A variety of resistivity logging tools which have varying radii of investigation have been developed to compensate for the effects of drilling-fluid invasion. Tools with large radii of investigation measure formation resistivity at points sufficiently removed from the borehole to minimize the effect of drilling-fluid filtrate. In addition, tools are available with medium and shallow depths of investigation which can be used to identify the extent and resistivity of invaded zones. These measurements can, in turn, be used to compensate measurements made by tools of larger radius of investigation and thereby provide more reliable estimates of true formation resistivity.

Representations of resistivity logs taken during a conventional resistivity survey (short, long, normal, and lateral devices) are presented in Figure 7.2. As shown in the figure, resistivity profiles run to determine formation resistivity commonly involve shallow, medium, and deep (short to large radii) investigating devices. One analytical technique used to calculate formation resistivity with multiple resistivity readings is discussed by Tixier, et al. (1965).

In addition to providing formation-resistivity measurements that can be used for fluid resistivity or porosity determinations, resistivity surveys can be used to provide lithologic determinations and stratigraphic correlations. Figure 7.2 shows the variations in measured resistivity which correspond to changing lithology. Certain resistivity tools provide better results for this purpose. The focused devices generally show greater vertical resolution than the long, normal, or lateral device. Point-resistance devices are also available which show stratigraphic delineation, but these devices provide a resistivity reading which is not representative of true formation resistivity due to the influence of borehole fluids.

Resistivity surveys can be used to identify permeable beds using microresistivity devices which can detect the presence of wallcake or drilling-fluid filtrate (Doll, 1971b). Thick layers of wallcake normally form at the face of permeable formations where filtrate is able to penetrate the formation. In addition, microresistivity devices can be used to determine the formation factor. In formations in which the fluids in the pore space near the borehole have

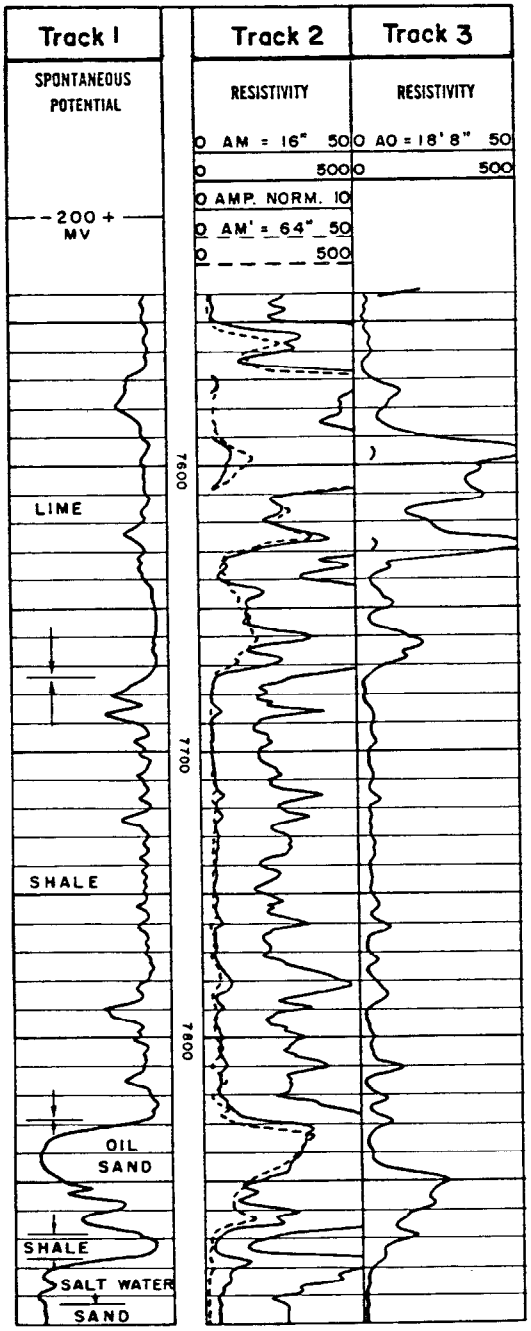

Figure 7.2. Conventional resistivity survey with lithologic correlation (Petroleum Extension Service, 1971)

been replaced completely by drilling-fluid filtrate, measurement of formation resistivity can be used to compute the formation factor using the resistivity of filtrate at the surface.

Resistivity logging can be used to identify areas of fracturing (Beck, et al., 1977; Pickett and Reynolds, 1969). When microresistivity devices cross fractures during logging, they generally show a resistivity anomaly due to the fluids contained within the fracture. Such surveys can be used to provide a qualitative identification of fracturing; because microresistivity tools are side wall devices which only investigate a portion of the borehole wall, they cannot be relied upon to locate all fractures. The dipmeter, also known as the fracture identification log, is a sophisticated application of microresistivity logging which provides better results when locating fractures and is discussed in this chapter (Section 7.2.4).

7.2.2 Radioactivity Logging

A variety of geophysical logging techniques which measure either the natural radioactivity or the attenuation of radioactive signals emitted from a radioactive source have been developed. These measurements can be used to identify specific geologic materials based on their characteristic natural radiation, or to assess density or fluid content and, therefore, porosity based on the ability to attenuate radioactive signals. The radioactive logging techniques available for use at injection-well sites include gamma, gamma-gamma, and neutron logging.

Gamma and Spectral-Gamma Logging

Gamma logging is a technique for measuring the natural radioactivity of geologic materials that is useful for correlating stratigraphy and determining clay content. Unstable isotopes of a variety of elements which spontaneously decay and emit radioactivity occur naturally in geologic materials. The most effective means of detecting

these unstable isotopes is through the measurement of the gamma radiation emitted during decay. Isotopes of uranium, thorium, potassium, and their various decay products are responsible for most of the radioactivity measured during gamma logging. The amount of radiation detected is directly proportional to the amount of these isotopes present in a specific formation. Shales and clayey materials commonly emit more gamma radiation than most other geologic materials because of the abundance of potassium. Consequently, gamma logging is frequently used to detect clay and shale and to determine the relative amount of clay within a specific formation. In contrast, clean sand formations usually exhibit a very low level of radioactivity unless radioactive contaminants are present. The schematic diagram of a gamma log shown in Figure 7.3, illustrates the high radioactivity measured during gamma logging opposite shales or shalely materials.

Since specific rock types exhibit characteristic levels of gamma radiation based on mineral content, individual formations can be distinguished and their lithology tentatively identified using a gamma log. Within a specific area, individual beds will exhibit a typical level of radioactivity. Thus, gamma logs can provide a fairly specific "fingerprint" of individual formations which can be used for stratigraphic correlation. Gamma logs are also used extensively to provide background measurements of radioactivity necessary for other radioactivity logging techniques.

In addition to standard gamma-logging techniques, a second gamma-logging technique, known as gamma spectrometry, can be utilized. Radioisotopes emit radiation with energies characteristic of that isotope. Gamma spectrometry utilizes this phenomenon to identify specific isotopes present in a formation by providing a means of studying the energy distribution of gamma photons measured during conventional gamma logging. Gamma spectrometry increases the relative amount of information provided by the more conventional gamma-logging technique and greatly increases the ability to determine lithology and provide stratigraphic correlations. The ability to determine relative amounts of potassium, uranium, and thorium frequently provides a means of detecting unique signatures of individual clay types. In addition, the detection of anomalously high uranium kicks associated with many fracture systems becomes possible.

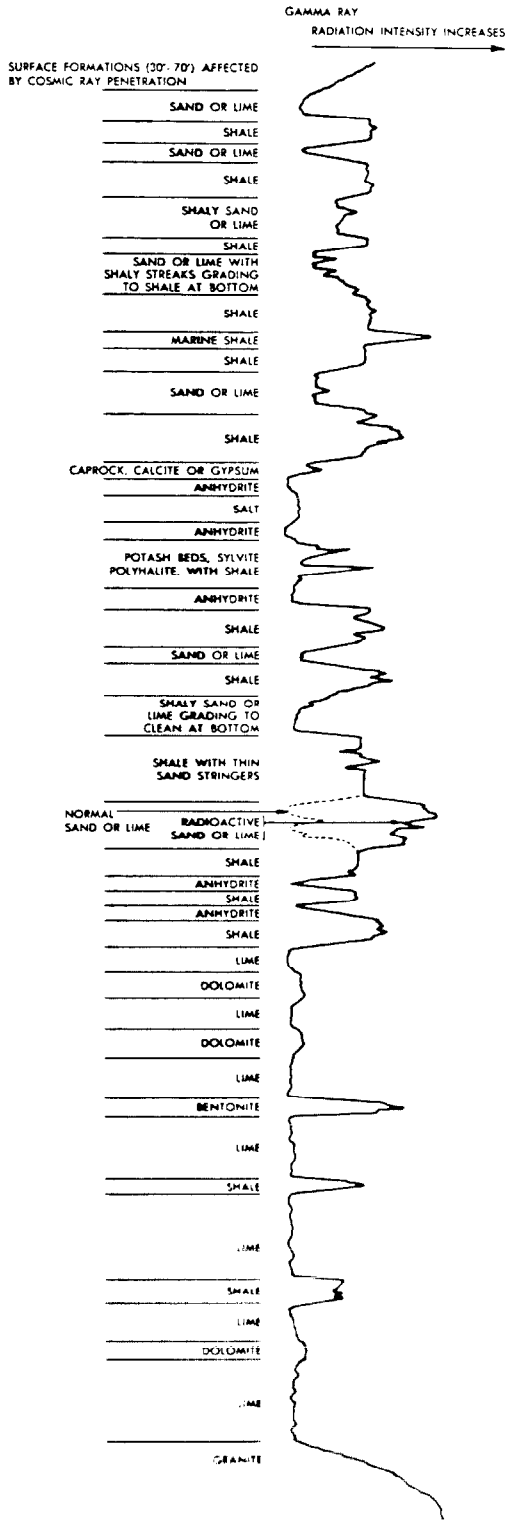

Figure 7.3. Schematic diagram of gamma log showing lithologic correlations

This capability can facilitate the identification of fractured zones of clayey material.

Gamma-Gamma Logging (Density Logs)

The gamma-gamma log measures the apparent density of geologic material which, in turn, can be used to determine porosity and to indicate lithology. The gamma-gamma logging device employs a radioactive source that emits gamma rays and a sensor that detects the portion of these gamma rays which are back-scattered into the borehole. The observed back-scattering results from collisions between the gamma rays and the electrons in the formation. The proportion of gamma rays that are back-scattered depends on the density of electrons present in the formation material and thus is proportional to formation density. The gamma device actually measures the bulk density of a material, or the actual density of the formation based on the relative amount and density of the geologic matrix and the fluids contained within the matrix. If a density value for both the formation matrix and the fluid contained within the matrix can be assumed, the porosity of that formation can be estimated (Alger, et al., 1963; Tittman and Wahl, 1965; Wahl, et al., 1964; Holm and Kleinegger, 1976).

Standard estimates of electron density for both formation matrix materials and fluids are generally available; and, if general lithologic and formation-fluid characteristics are known, gamma-gamma logs provide an effective means of determining porosity. When used with other logging techniques, gamma-gamma logging can yield relevant information for determining lithology, shale content, and fluid saturations.

The radius of investigation of gamma-gamma logs is shallow, [only 6 inches (15.24 cm)]; consequently, the logging tool must be pressed tightly against the wall of the borehole, limiting the ability of the tool to evaluate more than 25 percent of the borehole. Density logs can be significantly affected by wall cake and irregularities in borehole contours because of this shallow depth of investigation. In fact, this sensitivity to wall cake thickness enables their use to determine that parameter.

Neutron Logging

Neutron-logging tools are used to determine porosity and lithology (Wahl, et al., 1970; Tittman, et al., 1966 Ahmed, 1977; Calvier, et al., 1971). They contain a radioactive source that emits high-energy neutrons and a sensor that detects radiation resulting from the interaction of the emitted neutrons with formation materials (lower energy neutrons and gamma photons).

Although neutrons and gamma photons are present at a variety of different energy levels, neutron-logging tools contain sensors which detect certain energy levels only. The names of the neutron-logging tools generally indicate which type of radiation is being measured and include neutron-gamma, neutron-thermal neutron, and neutron-epithermal neutron logging tools. In addition, a specialized application of neutron logging, known as pulsed neutron logging, or decay-time logging, is available. This technique employs a source which emits a discrete pulse of neutrons and a detector that is sensitive to gamma rays emitted by the interaction between the pulses of neutron and the formation.

Since the neutron emitted by the source is affected by the hydrogen atoms present in the formation, neutron logs essentially provide a measurement of the amount of hydrogen present. If the hydrogen contained in the formation is present primarily in formation fluids, neutron logs indicate the amount of pore fluid present which can be translated directly into a measurement of porosity in a saturated formation. However, neutron logs will not yield accurate measurements of porosity in materials such as shale or hydrated gypsum that contain hydrogen that is not associated with pore fluids.

Neutron logs can be run in both cased and uncased holes, and their use has been suggested in the evaluation of the condition of borehole cement by identifying areas of high porosity. The use of neutron techniques for cement logging however is limited, since cements are generally hydrated chemical complexes and, therefore, do not allow easy interpretation.

Pulsed neutron logs were originally developed to identify hydrocarbons by differentiation of fluids which

contain chloride (i.e., saline water), and those which do not (i.e., oil and gas). These logs offer the capability of identifying saline water and might be useful in distinguishing fresh from saline-water bearing zones. Because these logs can be run in cased holes, they may be useful in identifying areas of fresh-water degradation.

It must be noted that special precautions must be taken if a neutron-logging device is lost in the borehole. The borehole must be abandoned and grouted to the surface; some states require the installation of monitor wells around the neutron source. A monument must be installed at the abandoned well to denote the presence of radioactive material.

7.2.3 Acoustic Logging

Logging techniques which measure the acoustic properties of geologic materials are known as acoustic or sonic logs. These techniques utilize logging devices containing one or more transmitters which emit high frequency pulses of acoustic energy and a number of receivers spaced at varying distances from the transmitter. The transit time of the sonic wave, which is the reciprocal of sonic velocity, and the amplitude or attenuation of the sonic wave is measured. A variety of lithologic parameters influence the characteristics of the sonic wave (Pickett, 1963), and the measurement of these acoustic parameters allows the determination of porosity and the presence of fractures, if sufficient additional information is present. The various acoustic logs include the sonic velocity, sonic amplitude, and variable density logs, as well as the acoustic-borehole televiewer.

Sonic-Velocity Logging

Sonic-velocity logs are used to determine formation porosity by measuring the time required for a sonic wave to travel between two receivers (Tixier, et al., 1959 and 1960). The velocity of a sonic wave through a geologic formation depends on properties of both the rock matrix and the formation fluids. The sonic velocity for typical formation liquids (i.e., oil and water) are essentially the same, and in cases in which no gas is present, sonic

velocity depends primarily on porosity and rock-matrix properties. This dependence on formation porosity is responsible for the principle use of sonic velocity logs to determine porosity.

There are several limitations in the use of sonic-velocity logs for determining porosity. Since sonic velocity depends on the matrix properties of the rock as well as on formation porosity, accurate determinations require knowledge of formation lithology. The use of sonic-velocity logs to determine porosity is also limited in unconsolidated or poorly compacted materials because the rock matrix does not transmit acoustic energy well and sonic velocity is more readily influenced by formation fluids. In addition, sonic-velocity logs do not provide a measurement of secondary porosity in fractured or vugular formations. However, sonic-velocity logging can provide a means of measuring secondary porosity by substracting sonic velocity-log porosity measurements from total porosity measurements made with other logs.

Sonic-Amplitude Logging

Sonic-amplitude logs measure the attenuation of a sonic wave as it travels through a formation. A variety of formation properties determine wave attenuation, but poor compaction of unconsolidated materials and formation vugs and fractures appear to have major impacts on the ability to transmit the elastic energy of a sonic signal. In addition, when applied in cased holes, some waves will be attenuated based on the nature of the cement bond. This characteristic response allows sonic-amplitude logs to be useful when identifying areas of fracturing in uncased holes or when determining the quality of cement bonding in cased holes.

Experience has shown that compression and shear sonic waves emitted by the tool are attenuated differently by horizontal and vertical fractures. Compression waves are attenuated most in areas of vertical and high-angle fractures, while horizontal or low angle fractures affect shear waves to a greater extent. Thus, attenuation in either the compression or shear components of the sonic wave can be useful in determining extent or orientation of formation fractures. The identification of fractures from the interpretation of amplitude logs is qualitative and must be accomplished with drilling and core data. Amplitude logs

may fail to distinguish between actual fractures and bedding planes, shale or clay streaks, or "healed" fractures (Pickett, 1963; Morris, et al., 1964; Koerperich, 1978).

Sonic-amplitude logging techniques have also been applied in cased holes to determine the extent of cement bonding to the casing (Grosmangin, et al., 1961; Bade, 1963; Fertl, et al., 1974). Cement-bond logs operate on the principle that the energy loss of a sonic pulse traveling through a casing that is firmly bonded to cement will be greater than the loss of energy of a pulse traveling through a free casing. In this manner, sonic amplitude logs, by identifying areas of the casing in which the acoustic signal is poorly attenuated, can identify areas of poor cementing. Application of these logs to injection wells with tubing requires that the tubing be removed so the acoustic signal can be applied directly to the casing.

Variable-density logging is a specialized sonic-amplitude logging technique for fracture detection in uncased holes and cement-bond evaluation in cased holes.

Acoustic Televiewer

The acoustic televiewer produces an "acoustic picture" of the surface of a borehole (Zemaneck, et al., 1970; Wiley, 1981). It has been used primarily as a tool for examining the condition of borehole wall and can be used to determine the presence and extent of induced and natural fractures at the face of the borehole. The televiewer can also be applied within cased wells to determine the condition of the casing.

The acoustic televiewer operates by emitting a pulsed, concentrated beam of high frequency sound energy from an acoustic transducer. The pulses of sound energy are directed toward the wall of borehole where a portion of each pulse is reflected back to the televiewer. The physical properties of the borehole wall determine the amount of acoustic energy reflected. Smooth and/or hard surfaces reflect acoustic energy better than rough and/or soft surfaces. Thus, smooth surfaces will result in the transmission of a higher energy signal. These signals are displayed on an oscilloscope. A two dimensional image of the borehole wall showing areas of various brightness

is produced (Figure 7.4). The televiewer log is obtained by photographing the oscilloscope presentation.

The acoustic-borehole televiewer provides a means of detecting and assessing natural and induced fractures, as well as other nonconformities such as vugs. In cased-hole applications, the televiewer will show pits or holes in the casing. Effective use of the televiewer requires a homogeneous liquid such as water or drilling fluid within the borehole. In the past, the high solids content of some drilling fluids has proved problematic to the effective operation of the televiewer. The televiewer tool also requires near-perfect centralization within the borehole and a slow, constant logging speed.

Acoustic televiewers were used during the 1960s for borehole inspection. However, there was not enough sustained interest in their use to justify maintaining the services. Borehole televiewer services entered a period of relative disuse and now are difficult to obtain. With the renewed interest in fracture identification and evaluation from increased oil exploration, the use of secondary recovery techniques, and other energy-related interest, the use and availability of acoustic-borehole televiewer services may increase.

7.2.4 Other Geophysical Logging Techniques

A number of other geophysical techniques are available for use in formation and well evaluation. These techniques include dipmeter, nuclear magnetism, caliper, casing inspection, temperature, noise, and radioactive tracer logging methods. Each is discussed below.

Dipmeter

Dipmeter surveys are run to determine the strike and dip of the formation through which a borehole passes and, accordingly, can provide valuable information in identifying structural and stratigraphic features of the local geography. Additionally, dipmeter surveys are capable of identifying areas of fractures and are frequently referred to as fracture identification logs (Brown, 1976; Beck, et al., 1977).

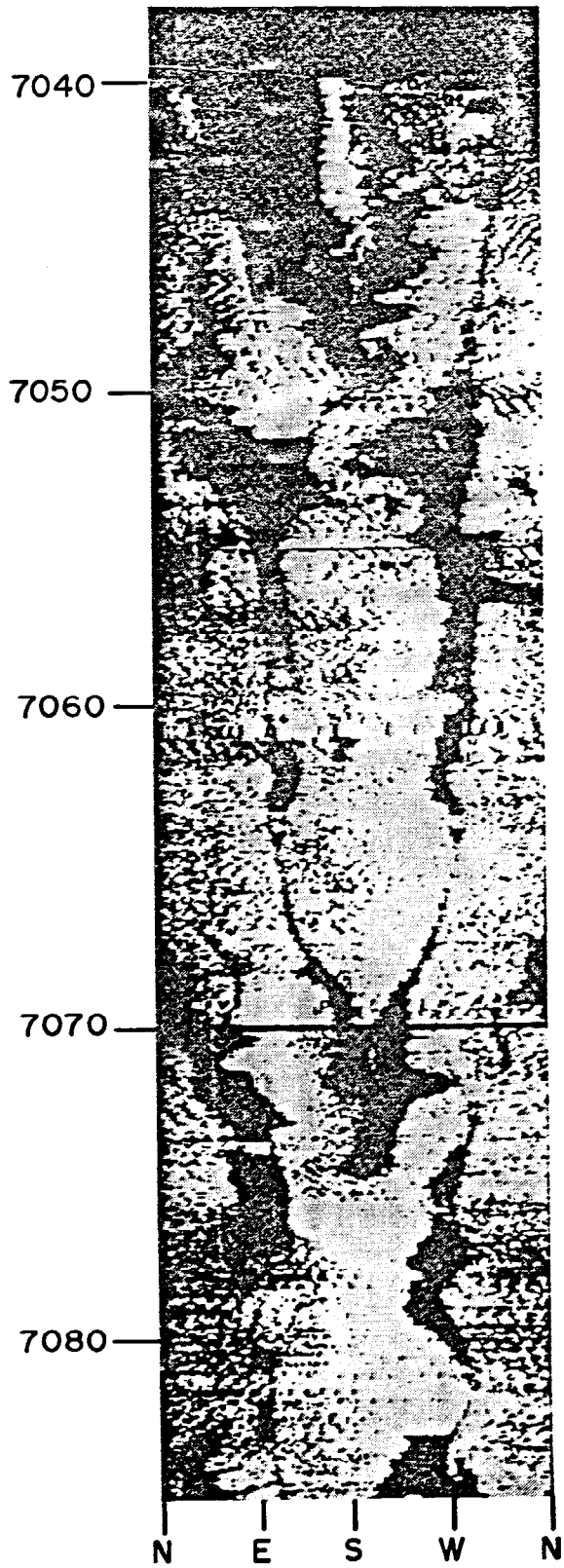

Figure 7.4. Acoustic televiewer log showing natural fractures (Zemanek, et al., 1970)

The dipmeter tool consists of a set of three or four contact electrodes (pads) located on individual extension arms, spaced equally in the plane perpendicular to the borehole. Older tools have employed microresistivity devices as contact electrodes, while newer tools utilize laterolog-type devices which allow greater penetration and resolution. These electrodes produce individual resistivity/conductivity measurements for each pad. In addition to the contact electrodes, the dipmeter tool also contains two caliper arms to measure borehole diameter and devices to measure the inclination of the borehole and the orientation of the tool as it rotates during descent into the borehole. The typical dipmeter log will contain numerous curves for deviation, azimuth, relative bearing, caliper and resistivity/conductivity (Figure 7.5).

The direction and angle of formation dip can be identified by comparing each electric logging curve provided by the dipmeter survey. Each of the curves can be correlated by finding points common to each. If the formation bedding plane is not identical to the plane common to the individual electrodes, the curves will be displaced by a distance characteristic of the dip and strike of the formation. Analysis of dipmeter curves to quantify dip and strike requires visual correlation of the microresistivity curves and solution of the spatial configuration by mechanical simulations, nomograms, or stereographic projections. Interpretation of dipmeter results is now possible by computer analysis of data recorded digitally on magnetic tape. Discussions of dipmeter tools and analytic techniques are available from service company publications (Schlumberger, 1970).

The most important application of dipmeter surveys to injection-well construction is as a tool for fracture identification and evaluation. A dipmeter survey locates fractures by observing anomalies in formation conductivity. Fluid-filled fractures at or near the surface of the borehole will generally result in localized areas of high conductivity which may be detected by one or more of the dipmeter electrodes (depending on the orientation of the fracture and position of the electrodes). As each electrode crosses a fracture, it shows a higher conductivity curve than shown by an electrode in contact with unfractured

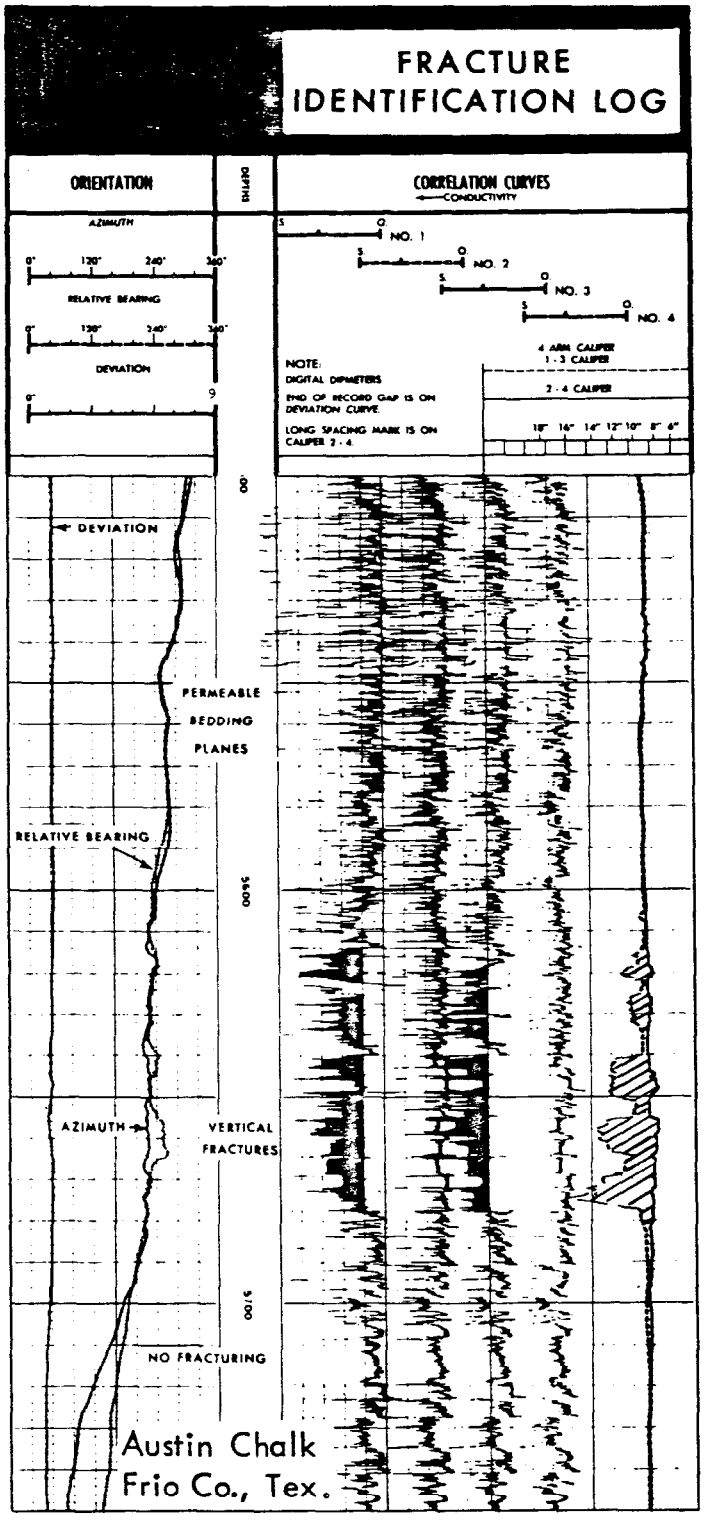

Figure 7.5. Dipmeter log showing fracture correlation (Brown, 1978)

formation material. The various patterns of conductivity anomalies resulting from different electrode positions as the tool crosses the fractured zone are shown in Figure 7.6. The four-curve presentation is used to distinguish between permeable bedding planes and vertical fractures (Figure 7.5). Permeable bedding planes will show sharp excursions to the left on all four curves. Vertical fractures will usually be seen on only one or two curves at a time. The four-curve presentation is also used to orient vertical fractures with respect to compass bearing.

Dipmeter surveys (fracture identification logs) offer many advantages over other techniques of fracture identification. Dipmeter results give a qualitative measure of fracturing as well as an indication of the dip and strike of the fracture. The microfocused device utilized by dipmeter tools gives greater resolution and a deeper range of penetration. They are sensitive to hairline fractures but not affected by healed fractures which may affect other techniques and give anomalous results.

Nuclear Magnetism Logging

Nuclear magnetism logging (NML) is a technique in which an external magnetic field is used to align (polarize) spinning hydrogen nuclei in a different orientation than found in the earth's magnetic field (Brown and Gamson, 1966; Hull and Coolidge, 1960; Timur, 1969; Loren and Robinson, 1970; Loren, 1972; Herrick, et al., 1979). After the external magnetic field is removed, the return of the nuclei to a normal orientation is observed. These observations allow the determination of fluid content, porosity, and formation permeability as well as the relative amounts of hydrocarbons and water. It is the only logging measurement which offers a means of making a direct measurement of the hydrogen found in the formation fluids and not that which is adsorbed onto or chemically bound in the rock matrix itself. NML signals can also be used to determine specific fluid saturations.

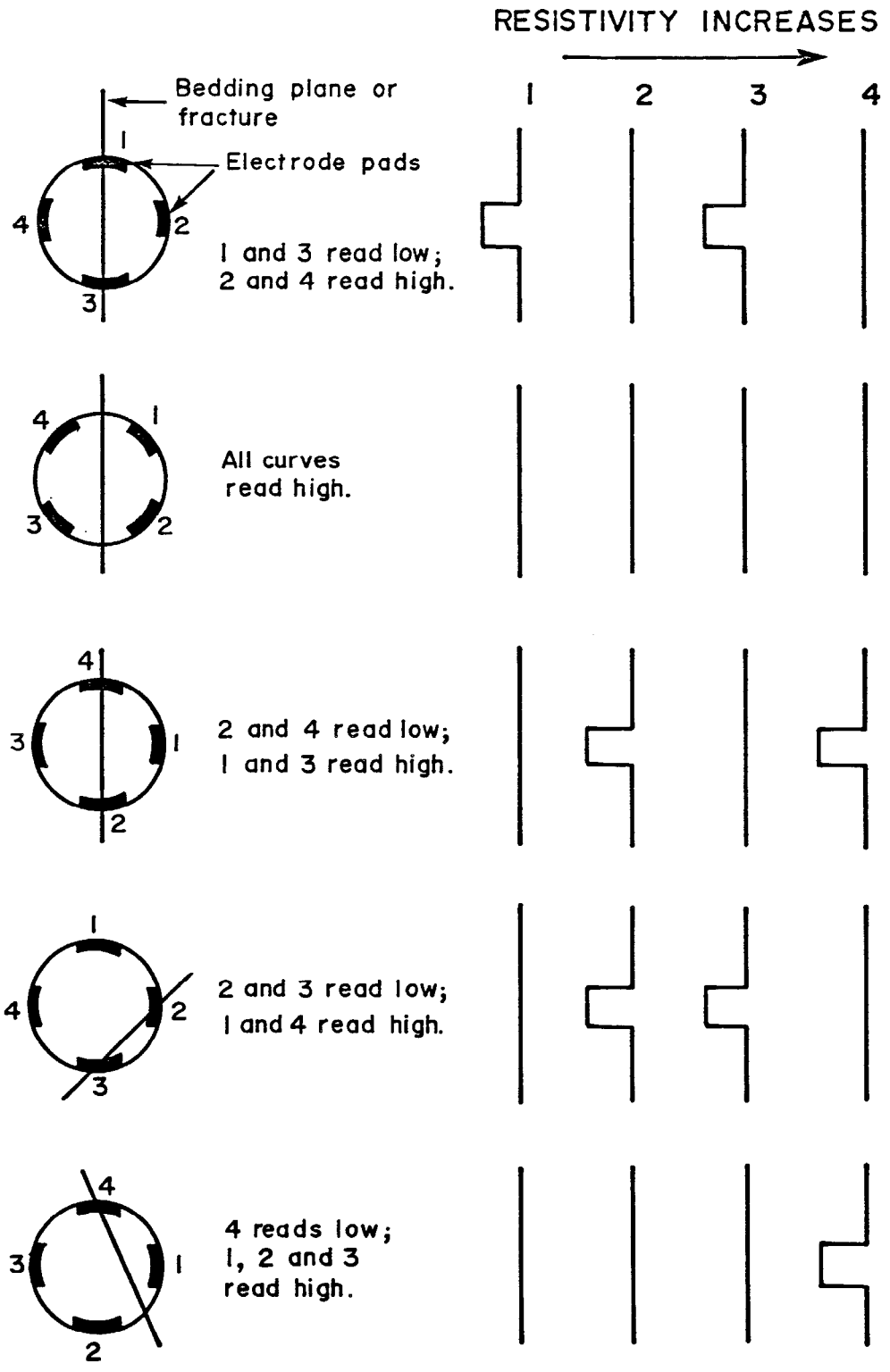

Figure 7.6. Schematic diagram showing principles of dipmeter logging (Brown, 1978)

Caliper Logging

The caliper log is a record of borehole or casing diameter as it varies with depth. Caliper logging tools have two to six arms or feelers which detect changes in hole diameter as the tool is raised in the hole. Changes in hole diameter are relayed electronically to the surface where they are recorded. Average hole diameter and/or the extension of individual feelers may be recorded.

Caliper logs are commonly used because they provide information essential to formation evaluation and well design. A record of diameter over the entire depth of a borehole allows the estimation of the amount of cement required for completion and facilitates the use of other geophysical logs which are dependent on hole diameter measurements for accurate interpretation.

Caliper logs also provide information valuable for lithologic interpretation. Changes in hole diameter are caused by drilling techniques and lithology. Lithologic characteristics which affect the diameter of the hole include the degree of cementation or compaction, porosity, presence of clay, bed thickness, vertical spacing from the adjacent bed, and the presence and orientation of formation fractures and vugs. For example, holes with enlarged diameter may result from caving and indicate sands or poorly consolidated material. Stretches of borehole with well defined, constant diameter indicate hard rock or well-consolidated formations. Formations containing swelling clays may result in loss of diameter. A build-up of wall cake, indicating highly permeable beds, may also result in a loss of hole diameter. Caliper logs can be instrumental in locating fractures and solution channels in carbonate materials. By identifying areas of structural weakness and nonconformity, caliper logs are useful in determining packer locations for effectively sealing the formation.

Caliper logging also has applications in cased holes. Extremely sensitive caliper logging tools can be used to identify casing joints and rough, corroded areas in casing. Caliper logs can be used to detect exaggerated distortions in the diameter of casing. Such measurements can be useful in determining potential areas of leakage or behind casing fluid movement.

Casing Inspection Logs

Logging tools are available to assess the condition of the casing in cased holes. The electromagnetic casing log operates by measuring changes in the magnetic properties of the casing (Smolen, 1976; Cuthbert and Johnson, 1975; Haire, 1977). This is accomplished in the simpliest case by lowering a permanent magnet wrapped with a coil of wire. Changes in magnetic properties (largely determined by metallic mass) of the material moving through the magnetic field will cause a current to flow through the wire coil, producing voltages which can be measured and recorded. This tool can identify areas of casing damage or corrosion by detecting changes in magnetic properties. This type of logging tool can also be used to locate casing collars and to provide a depth reference in the hole by marking each casing collar. Gamma logs are generally used as a complement to collar logs to provide a reference with the surrounding geologic formation. Electromagnetic casing logs can be used to locate casing perforations or length of screen within the well.

Another type of casing inspection log relies on detecting electrical flux leakage and eddy currents produced by casing irregularities. Still another variety which relies on phase shifting a low-frequency electromagnetic signal can be used to determine corrosion damage, collars, etc.

Temperature Logs

The temperature log locates areas of fluid movement in both cased and uncased holes by recording temperatures (Guyod, 1946; Peacock, 1965; Cooke, 1979; Welex, n.d.). A number of factors determine the temperature variation over the depth of the well. A natural temperature gradient will exist in the formation through which the borehole penetrates. However, a number of other factors can influence the temperature and these additional influences make the application of temperature logging to formation and well evaluation useful.

Movement of fluid into a borehole from a permeable formation will upset the normal temperature gradient in the well. If two or more beds are contributing water

with different temperatures into a well, measurements of temperature gradients can be used to estimate the relative flow from each bed.

In cased holes, temperature logs can detect flow behind the casing. In an injection well, fluid which flows along the casing and is lost through a hole in the casing or around a packer at the bottom of the well will upset normal temperature gradients within the well. If pumping is stopped and the temperatures inside the well are allowed to equilibrate with the surrounding formation, a temperature log should identify areas behind the casing in which fluid flow has accrued (Geraghty & Miller, Inc., 1982).

Temperature logs are run in cased holes shortly after cementing to determine certain aspects of the cementing job; as the cement sets, it generates heat. Temperature logs are commonly run to identify the top of the cement and may also identify extended areas behind the casing where cement is not present.

Noise Logging

Noise logging is a relatively new geophysical technique which utilizes a sensor to detect sound energy created by the turbulent flow of fluids moving through channels, leaks, or flow constrictions (McKinley, et al., 1973; Robinson, 1976; McKinley and Bower, 1979). The application of noise logging of greatest interest to injection-well operators is the detection of fluid flow behind the casing.

Noise logs are obtained by lowering the device into the cased hole, recording a noise signal at discrete points within the well to determine the nature of flow in and around the borehole. The device records both the amplitude and the frequency of the acoustic wave. The frequencies of greatest interest in examining fluid flow in wells range between 300 and 6,000 Hz.

Radioactive Tracer Logging

Radioactive tracer logging is used to determine the path taken by injection fluids by introducing a radioactive

fluid into the well. The path of the tracer can be determined by identifying areas of increased radioactivity. Radioactivity is measured by a gamma-ray sensor (background measurements of natural gamma activity must be made prior to injecting the tracer) to identify resulting variations in formation radioactivity after injecting the tracer. The tracer must be of sufficient radioactivity that its presence can be detected over background levels of radioactivity. Radioactive materials with a relatively short half-life are generally used to minimize long-term effects of the test. The most commonly used tracer is iodine 131 which has a half-life of 8.04 days.

The injection of radioactive tracers has numerous applications, including permeability studies, evaluation of planned fracturing, and measurement of flow between wells. One of their primary uses in injection wells is to detect movement of fluid through a leak at any point in the casing or beneath the bottom of the casing or into channels in the cement of the borehole.

7.2.5 Logging Programs

The formulation of logging programs for formation evaluation at specific injection-well sites is dependent on lithology, formation-fluid content, and specific data requirements at the site. If a complete logging program is planned to provide an extensive analysis of formation characteristics, a resistivity survey, one or more porosity logs, and various other logs including caliper, spontaneous potential, and gamma-ray logs will likely be included. However, such extensive logging programs may not be appropriate at injection-well sites where logging requirements are reduced by other data collecting programs or by the existing data base.

Resistivity surveys used in the more extensive logging programs typically include shallow, medium, and deep investigating logs. In conductive formations, the medium deep investigating tools are generally inductive devices while the shallow investigating tool may be either a laterolog or a spherically-focused induction device. In resistive formations, induction devices are not used because of reduced effectiveness in such environments and are replaced by guard or laterolog devices. In some areas the older, short-normal and long-normal and lateral devices may

still be in use. Microresistivity devices may also be included in logging programs at some injection-well sites for special analysis of wall cake and other borehole features. Spontaneous potential logs are also typically included in electrical surveys.

The choice of a porosity log (or logs) for inclusion within a specific logging program depends on lithologic complexity and an existing knowledge of formation lithology. In simple lithologies for which basic matrix-lithology parameters can be assumed, a single porosity log may be used. Choice of the specific log must be based on the characteristic limitations each technique exhibits in particular materials. For example, sonic logs should not be used to determine porosity in unconsolidated and poorly compacted sands since they perform poorly in such environments.

In situations in which the lithology is complex and poorly understood, it is advisable to include two or more porosity logs. Lithologic determinations are necessary to provide correct matrix parameters, and programs including several porosity logs increase the reliability of measurements and help to determine lithology (Pirson, 1957; Raymer and Biggs, 1963; Burke, et al., 1969; Poupon, et al., 1971; Harris, et al., 1971). Lithologic determinations are possible because the response of sonic, density, and neutron logs vary independently according to matrix compositions. Comparison of different porosity logs taken in the same material can yield reliable estimates of matrix mineral composition and porosity since individual log responses are well known. In some instances computers may be used to facilitate such analyses.

The inclusion of other logging techniques in a specific logging program is related to the special needs of the injection-well construction program. Perhaps the most common need is for fracture identification and evaluation. For this purpose dipmeter surveys (fracture identification logs), the acoustic borehole televiewer, or spectral gamma logs may be included in the logging program.

7.3 DRILL-STEM, PRESSURE, AND INJECTIVITY TESTING

A variety of techniques are available to test an injection well under actual flow conditions. These techniques can be utilized prior to setting casing to evaluate the performance of a well. Specific data to determine formation pressures, fluid characteristics, fracture pressures, and various formation hydraulic characteristics can be collected. These techniques include drill-stem testing, wireline formation testing, pressure and injectivity testing.

7.3.1 Drill-Stem Testing

Drill-stem testing is a technique that provides a means of temporarily completing a well to allow formation fluids to flow under natural formation pressures. While developed originally to collect fluid samples, drill-stem testing is now used to determine a number of other characteristics including injection formation pressures, average effective permeability, borehole damage, and permeability changes or barriers.

An assembly connected to the drill stem which contains a packer (or packers) to isolate a particular formation is lowered into the borehole. A valve located in the assembly is closed to prevent drilling fluid from entering the drill stem and thereby maintains atmospheric pressure within the drill-stem pipe as it is lowered into the borehole. Once the packers are seated and the formation undergoing evaluation isolated, the valve is opened to allow drilling fluid and formation fluids to flow into the drill stem.

The drilling fluid in the isolated zone of the borehole is under the pressure exerted by the column of fluid before seating the packers and will flow into the drill stem as it is opened. If the formation is permeable, fluids will enter the borehole and follow the drilling fluid up into the drill stem. If left unchecked, the drilling fluid and formation fluid will continue to enter the drill pipe until the weight of the column of liquids equals the pressure exerted by the fluids in the formation. However, the valve is generally closed in a short

time and the pressure is allowed to build again as formation fluids flow into the isolated portion of the borehole. A pressure guage is located in the assembly which measures changes in pressure over time. These pressure changes are recorded downhole and the instrument and recording brought to the surface after the test. The valve can be opened or closed several times and the pressure changes recorded. After the pressure testing is completed, the valve is closed and the packer(s) is released. The drill stem and attached testing equipment are raised out of the hole, bringing with it the fluid samples contained in the drill stem. The fluid sample, which may contain both drilling and formation fluids, is collected for analysis.

Drill-stem tools with a variety of different designs offer a variety of drill-stem testing techniques. Various drill-stem tools are presented in Figure 7.7. In addition to single and double packer arrangements (straddle packers), the packers themselves may vary significantly in the way they are expanded to seal the borehole. A variety of valve arrangements, pressure controlling systems, and procedures are also available. (Petroleum Extension Service, 1968; Edwards and Winn, 1974).

A schematic diagram of a pressure recording taken during a drill-stem test is presented in Figure 7.8. This diagram shows the general form and inflection points of a typical pressure record. As the tool is lowered into the hole and the weight of the drilling-fluid column increases, the pressure rises in the drill-stem tool. The tool is seated, and the initial hydrostatic drilling-fluid pressure can be observed (A). The drill-stem valve is opened, and the pressure is allowed to fall as formation fluids begin to flow into the borehole. The valve is then closed and the pressure is allowed to build. This sequence of events is called the initial flowing and shut-in period and is intended to relieve any over-pressured conditions resulting from drilling or setting the drill-stem packer. After the valve is closed, the pressure builds toward the static reservoir pressure (B).

Next the valve is opened to initiate the second flowing and shut-in period. The pressure drops as the valve opens, and formation fluids begin to flow, raising the flow pressure as the column of fluid in the drill-stem

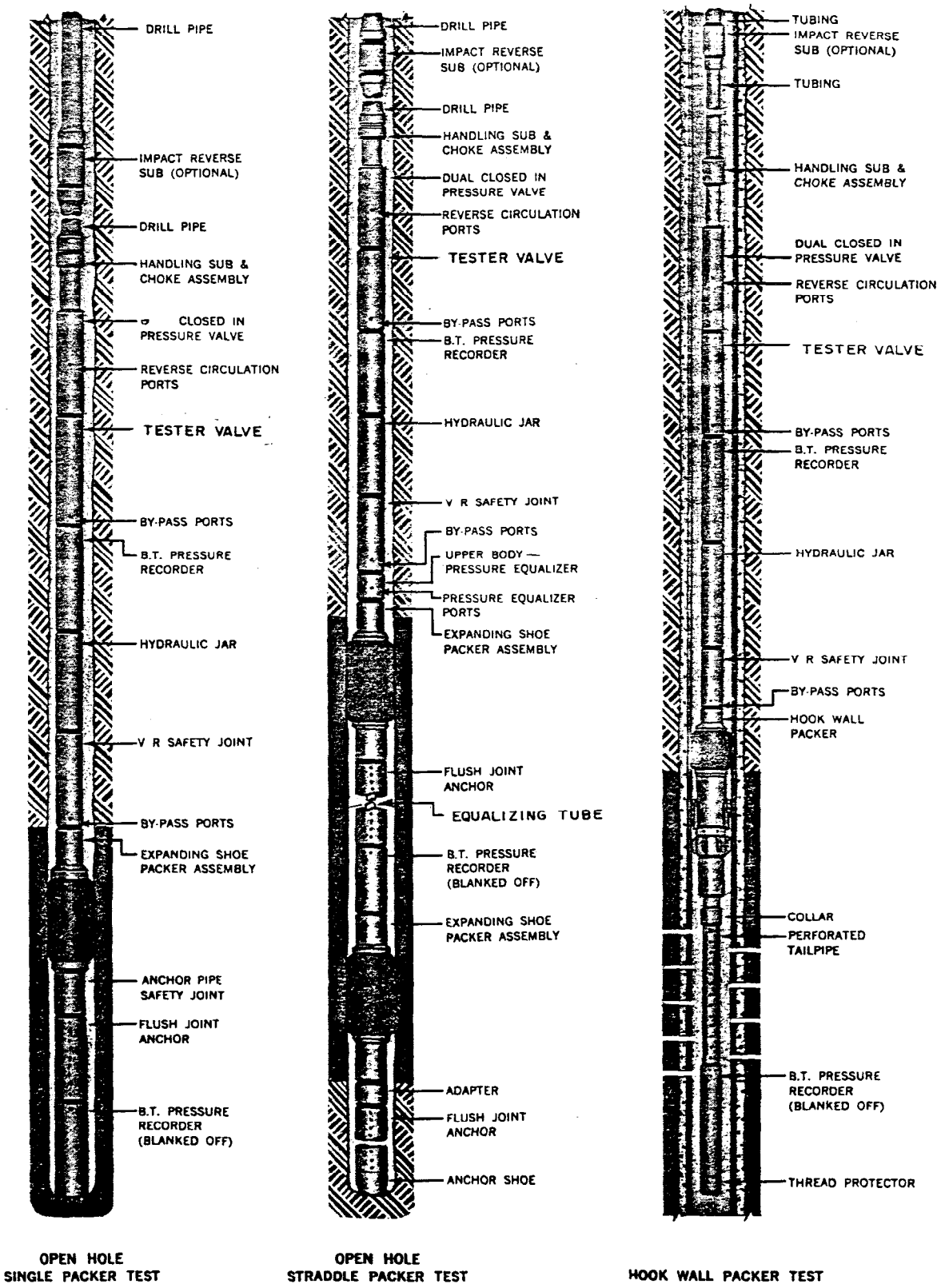

Figure 7.7. Drill-stem testing tools (Petroleum Extension Service, 1978)

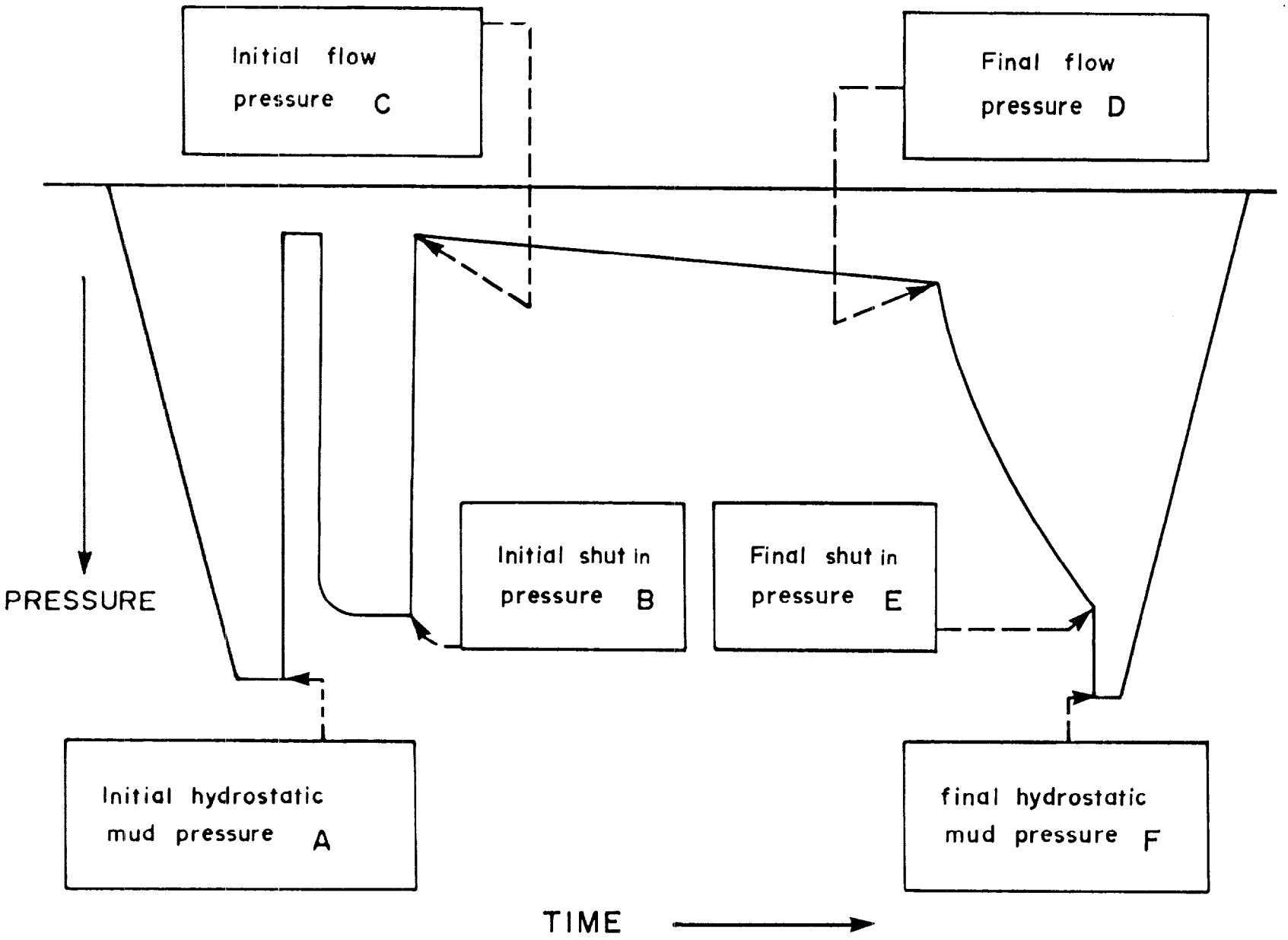

Figure 7.8. Schematic diagram of a drill-stem test (Allen and Roberts, 1978)

pipe increases (C). Flow is allowed to continue for sufficient time to allow adequate analysis of pressure data, then the valve is closed (D). A gradual rise in pressure is observed which will approach the original shut-in pressure of the formation (E). Depending on the objective of the test, the valve can be opened again to allow an additional flow period to validate the original test and to allow for more sophisticated analysis of test results. After the test is completed, the packers are unseated and the pressure returns to that exerted by the column of drilling fluid in the borehole (F). The tool is then lifted out of the hole and the pressure drops accordingly. The actual duration of the test is variable, but generally ranges between two and four hours in addition to the time required to lower and raise the equipment.

Analysis of the transient pressure response observed during drill-stem testing can be used to quantify many of the tested formations hydraulic parameters. An equation developed by Horner (1951) serves as a basis for much of this analysis. The equation assumes radial flow, homogenous formation, steady-state conditions, infinite reservoir, and single phase flow and shows that:

$$P_f = P_r - \frac{162.6\ Q \mu B}{Kh} \log \frac{T + \theta}{\theta} \qquad (7\text{-}1)$$

where,

P_f = formation pressure during build-up T(psig)
P_r = actual reservoir pressure (psig)
Q = rate of flow (bbl/d) before shut-in
μ = fluid viscosity, centipoise
B = formation volume factor
K = permeability of formation, millidarcys
h = formation thickness, feet
T = time flow, minutes
θ = time of shut-in, minutes

If it is assumed that during the flow period steady-state, single-phase flow occurred, the equation may be rearranged to show that:

$$M = \frac{162.6\ Q\mu B}{Kh} = \frac{P_r - P_f}{\log \frac{T + \theta}{\theta}} \qquad (7\text{-}2)$$

The (M) value can be shown to be a constant for steady-state flow. If it is plotted against $\log \frac{T + \theta}{\theta}$, a straight line with a slope of m should accordingly result. Such plots are commonly done in drill-stem transient pressure analysis. If extrapolated to infinity, the plot should provide the static bottomhole pressure. By determining the slope of this line, the permeability (K) or transmissivity (Kh) can be computed since the other components of M are easily identified. These measurements of permeability are generally considered superior to those obtained from core analysis since they represent an average value over a larger extent of the formation. These plots can also be used to identify changes in formation permeability or flow barriers since such conditions will result in an abrupt change in the slope of the line. Similar analysis can be used to determine loss of permeability in the formation near the borehole resulting from drilling procedures.

The analysis of drill-stem test data can be used to determine a number of additional parameters and has been widely documented in the literature. In addition to the numerous textbooks on petroleum geology and engineering, reference material which can be used for summary as well as detailed discussions of drill-stem analysis are available (Murphy, 1977; Mathews and Russel, 1967; Earlougher, 1977; Society of Petroleum Engineers, 1967 and 1980).

7.3.2 Wireline Formation Testing

In the 1950s, wireline formation testing tools were developed to provide a quick and inexpensive means for obtaining fluid samples and rudimentary pressure data. The tool is run into the borehole and is seated in selected formations for which data is required. The tool can be used to evaluate several formations during one run and accordingly is referred to as a repeat formation-testing tool. The tool contains several small chambers for collecting fluid samples, limiting the number of samples obtained

by the number of collection chambers available. The tool is seated by expanding a piston at the desired depth which pushes the tester into the side of the borehole. A small valve on the side of the tool is pushed into the formation to collect fluid samples. The apparatus contains a pressure guage which transmits pressure curves back to the surface during testing.

The use of the wireline formation tester is limited by the capacity of the fluid collection chamber and by the nature of the pressure data collected. Special care must be taken to insure that fluid samples taken during sampling are representative of true formation fluids and not of the drilling-fluid filtrate which has invaded the formation. To avoid collecting filtrate, fluid samples are withdrawn during a pretest. This liquid is not collected, but fluid pressure in the formation adjacent to the borehole is monitored and recorded. This recording provides data useful to formation evaluation. After the pretest liquid is withdrawn, formation fluid samples are withdrawn and collected at a high flow rate. Pressure data is again collected and finally the valve is closed. Shut-in pressures which approach natural formation pressures are then recorded. A schematic diagram of a pressure recording from a wireline formation tester is presented in Figure 7.9. In a manner similar to the interpretation of drill-stem testing, pressure and fluid samples taken during wireline-formation testing provide information relevant to determining formation characteristics (Moran and Finklea, 1962; Schultz, et al., 1975; Smolen and Litsey, 1979).

7.3.3 Pressure Testing (Fracture Pressure Determination)

The hydraulic fracture pressure of the injection formation can be empirically determined through pressure tests (Earlougher, 1977). The general approach is to gradually increase the pressure at the surface of the formation while injecting a testing fluid until the pore pressure overcomes natural compressive forces and matrix tensile strength, and fractures are initiated in the rock matrix.

A diagram representing pressure changes at the face of the injection formation during a hydraulic fracture

operation is shown in Figure 7.10. At the beginning of the test, the pressure measured at the bottom of the hole is equal to formation pressure (P_o). Pressure is raised in the hole until the critical pressure is reached at which fracturing occurs.

Once the fracture is initiated, pressure will drop slightly back to a pressure (P_f) required to propagate the fracture away from the borehole during continued pumping. When the pump is turned off the pressure at the surface returns to normal, but pressures at the bottom of the hole remain high at a slowly declining shift in pressure (P_s).

In practice, pressure testing to determine fracture pressure is performed by increasing the injection rates incrementally and by observing downhole pressures; consequently, the test is frequently referred to as a step rate injectivity test. As shown in Figure 7.11, fracture pressure can be determined by plotting a graph of injection rate versus injection pressure and by identifying the inflection point at which the increased permeability from induced fracturing results. Generally, six to eight rates are used to bracket the estimated fracture pressure.

7.3.4 Injectivity Testing

Injectivity testing offers a means of evaluating the performance of the injection formation(s) during the final stages of injection-well construction. Although considerable information may be available concerning injection-zone properties based on previously run coring, geophysical logging, and drill-stem testing programs, actual performance of the injection zone is uncertain until pumping tests are run. Pumping tests can provide data to determine transmissivity and storativity coefficients. Evaluation of these coefficients is critical for determining injection rates and pressures and for predicting the protracted regional effects of continued injection on local formations. Pumping tests can also identify formation damage occurring during drilling and completion procedures which may require remedial measures such as hydraulic fracturing or other well stimulation techniques.

The hydraulic properties of the injection formation may be evaluated by either pumping from or injecting into

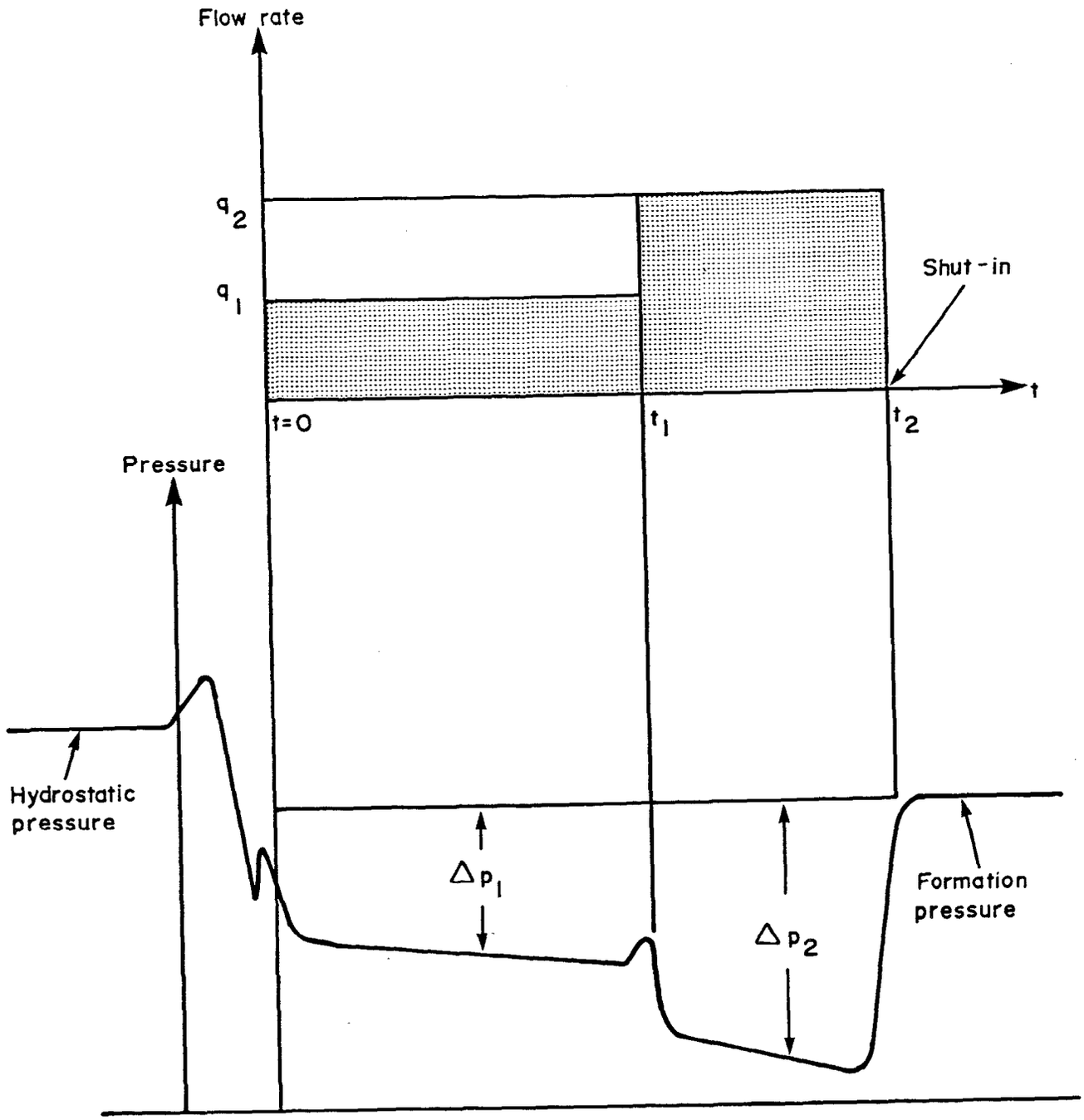

Figure 7.9. Schematic diagram of a wireline formation-testing pressure curve (Smolen and Litsey, 1979)

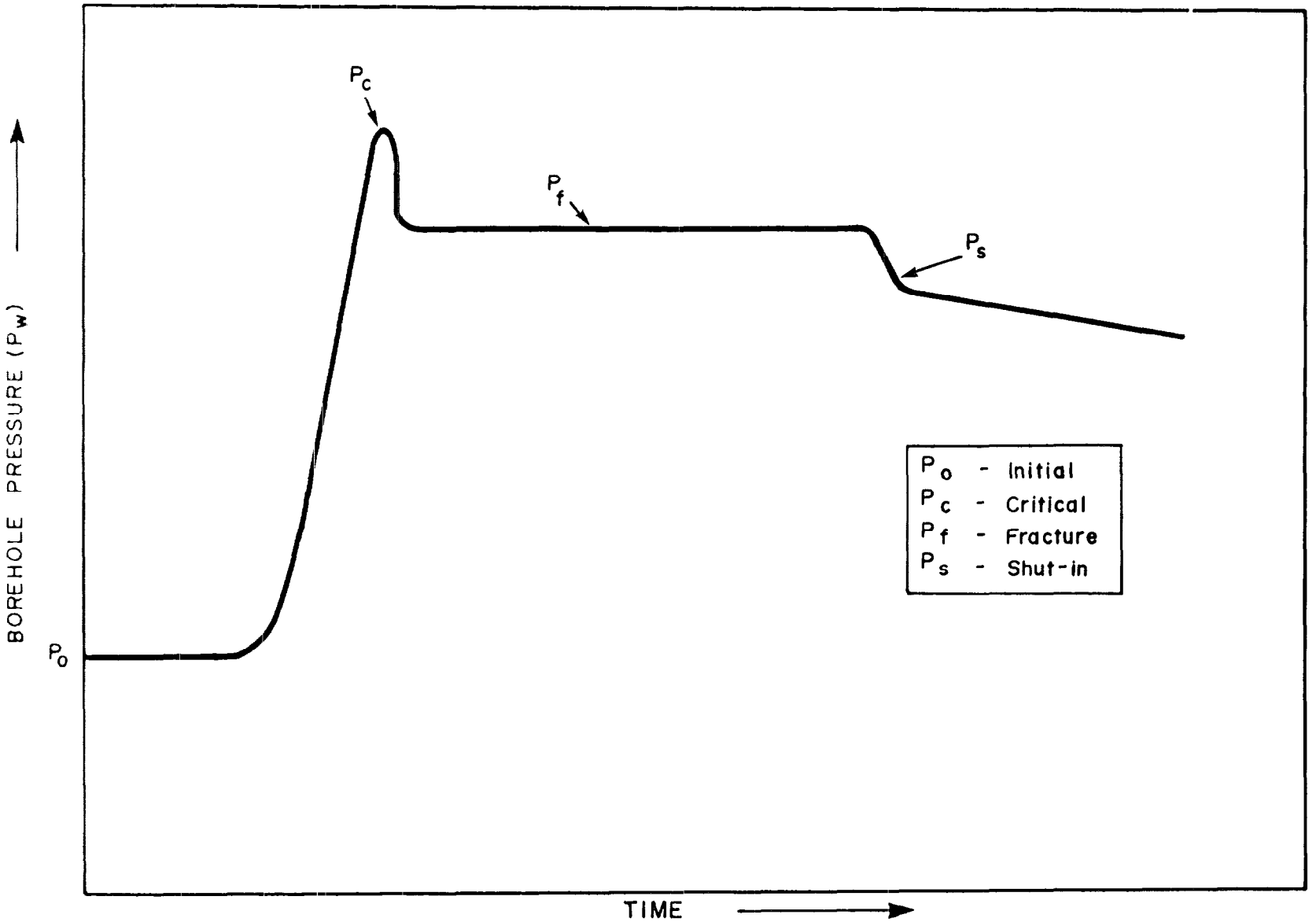

Figure 7.10. Schematic diagram of pressure change during hydraulic fracturing test (Smolen and Litsey, 1979)

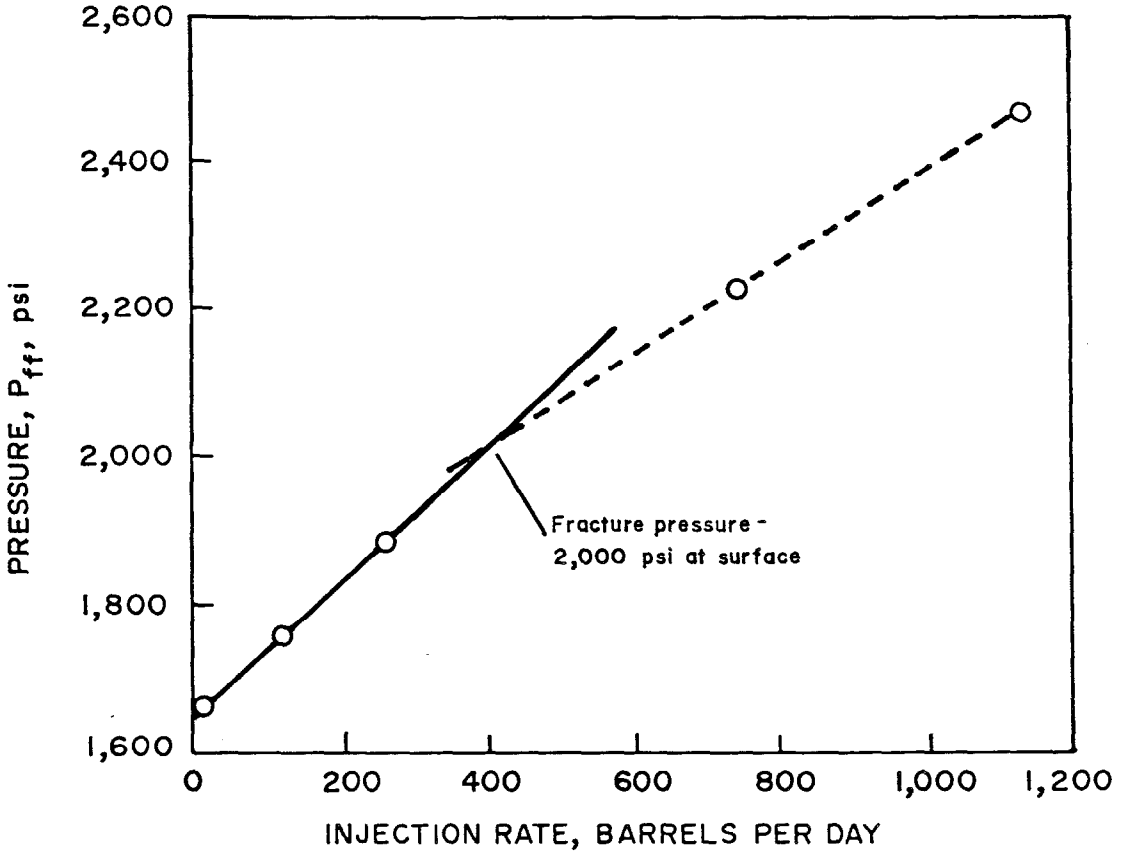

Figure 7.11. Schematic diagram of step-rate injectivity test (Allen and Roberts, 1978)

the formation. The methods of data analysis are essentially the same for either approach. However, it is considered advisable to duplicate operating conditions as much as possible and formation testing is usually accomplished using injection. Truck-mounted pumps are used for this purpose and treated and filtered water is injected. Care must be taken to insure compatibility between the injection fluid and the formation fluids and matrix. Commonly, the injection test begins by injecting at a rate which is a fraction of the final estimated rate. After injecting for a specified period of time, the injection rate is increased incrementally over a series of similar injection periods until the desired injection rate is obtained. Then injection is stopped and the reservoir is allowed to return to its original state. Injection rate and pressures are recorded throughout the test, and may also be recorded during the pressure falloff period after injection is stopped. The data recorded during injectivity testing may be subjected to a variety of analyses (Matthews and Russel, 1967; Lohman, 1972; Kruseman and DeRidder, 1970; Witherspoon, et al., 1967).

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8. CLASS I INJECTION WELLS

Class I injection wells include industrial and municipal disposal wells which inject fluid beneath the lowermost formation containing an underground source of drinking water. Historically these wells and well practices have been referred to as deep well injection or waste-disposal wells.

8.1 INDUSTRIAL DISPOSAL WELLS

Industrial disposal wells include those facilities that inject industrial wastes regardless of their toxicity or hazard to health. The use of injection wells for the disposal of industrial wastes has received increasing acceptance in recent years. Surveys of industrial well-injection practices (Donaldson, 1964; Ives and Eddy, 1968; Warner, 1972; U.S Environmental Protection Agency, 1974; Reeder, 1975) indicate that prior to 1950, no wells were designed specifically for the injection of industrial wastes. During the early 1950s, a few chemical companies began to apply well injection to the disposal of their wastes, and by 1974, 209 industrial waste-disposal wells were operating. While there are no current inventories of operating industrial waste-disposal wells, it is estimated that the number of wells may have doubled since 1974.

8.1.1 Description of the Practice

The increased use of industrial waste-disposal wells has been motivated by the high cost associated with disposing of wastes by other means. For example, the disposal of waste into surface-water bodies has been constrained by more restrictive effluent standards. In addition, the safe disposal of hazardous materials has proved to be increasingly problematic.

The major users of industrial waste-disposal wells are the chemical and allied products industries and oil refineries. Other industries which use these wells include food and paper, primary and fabricated metals, and machinery, electronics, and photographic industries. The geographical

distribution of these wells corresponds closely with the geographical concentration of major industries and adequate hydrogeologic conditions. The Texas/Louisiana region, followed by the Great Lakes States, have the largest numbers of industrial wells. Corresponding to the wide variety of industries utilizing injection wells for the disposal of their waste, the chemical characteristics of wastes injected into subsurface formations vary dramatically, and include inorganic salts, inorganic acids, caustic solvents, and a variety of organic compounds (Donaldson, 1972).

A recent survey of geologic formations used for industrial waste-disposal wells indicates that a wide variety of reservoir rocks are used (U.S. Environmental Protection Agency, 1974). The majority of wells are completed into sands and sandstones; carbonate rocks are the second most commonly used formations. Depths of injection strata vary considerably, but 90 percent are deeper than 1,000 feet (304.8 m) below land surface.

8.1.2 Injection-Well Site Evaluation

Selection of an environmentally acceptable site is extremely critical for Class I injection wells. Selection of an injection site begins with an evaluation at the regional level, then is narrowed to the vicinity of the site, and finally focuses upon the immediate well location. Table 8.1 lists factors that may be used to make the regional and local site evaluations.

Regional Evaluation

Figure 8.1 is a flow diagram which outlines a procedure for the regional evaluation of an injection-well site. The "yes-no" statements are oversimplified but, in concept, the diagram represents the procedure that is followed (whether consciously or not) in such evaluations.

Ideally, suitable regions for Class I wells should satisfy the following criteria: (1) extensive sedimentary sequence to provide an adequate injection zone and confining strata; (2) reasonably free of complex and extensive faulting and folding; (3) injection zones containing saline

TABLE 8.1
FACTORS TO BE CONSIDERED FOR GEOLOGIC AND HYDROLOGIC EVALUATION OF A SITE FOR INJECTION
(Warner and Lehr, 1977)

REGIONAL GEOLOGIC AND HYDROLOGIC FRAMEWORK

Physiography and general geology, structure, stratigaphy, ground water, mineral resources, seismicity, hydrodynamics.

LOCAL GEOLOGY AND GEOHYDROLOGY

A. Structural geology

B. Geologic description of subsurface rock units

1. General rock types and characteristics.

2. Description of injection horizons and confining beds. Lithology, thickness and vertical and lateral distribution, porosity (type and distribution as well as amount), permeability (same as for porosity), reservoir temperature and pressure, chemical characteristics of reservoir fluids, formation breakdown or fracture pressure, hydrodynamics.

3. Fresh water aquifers at the site and in the vicinity. Depth, thickness, general character, quality of contained water, amount of use and potential for use.

4. Mineral resources and their occurrence at the well site and in the immediate area. Oil and gas (including past, present and possible future development), coal, brines, other.

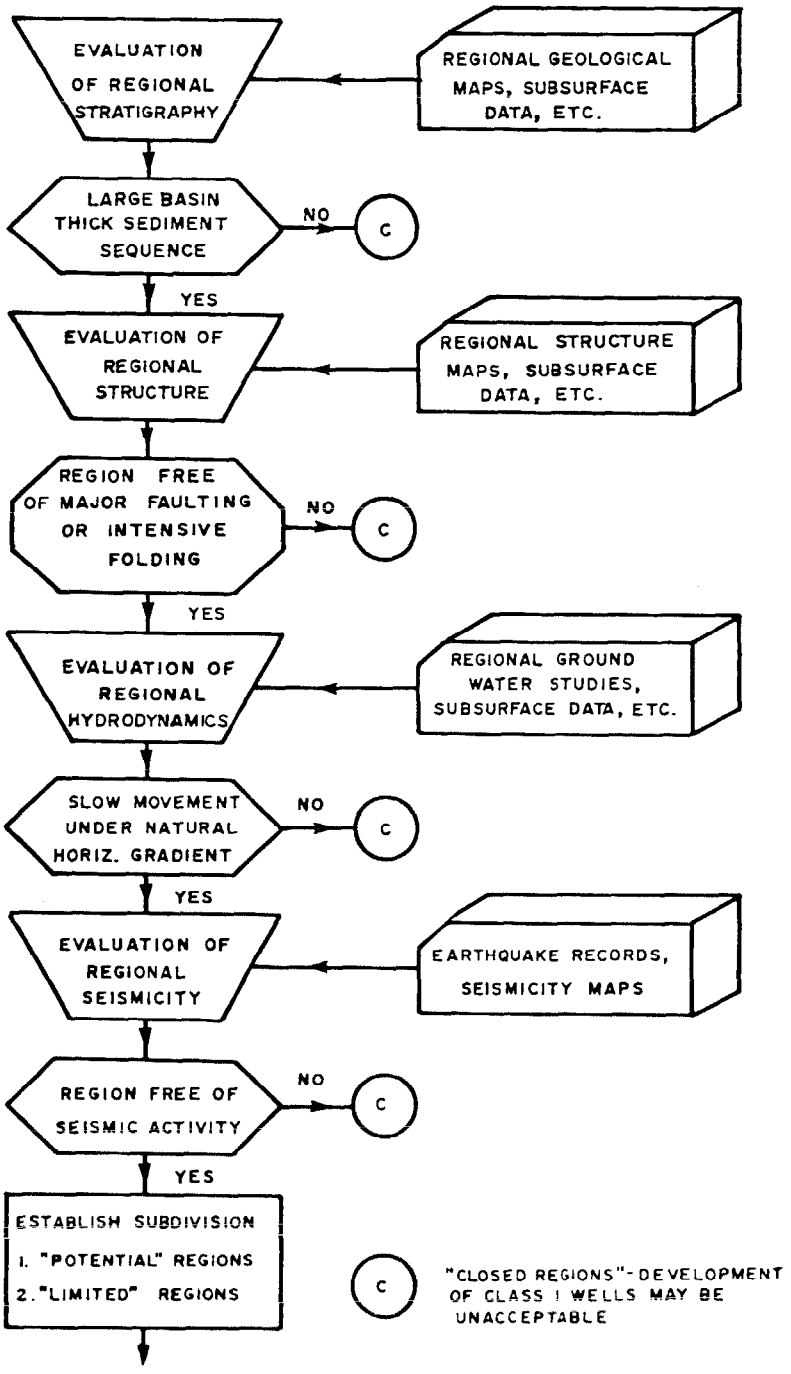

Figure 8.1. Methodology to make regional evaluation of suitability for Class I injection wells (van Everdingen and Freeze, 1971)

water and not interfering with mineral resources (oil, gas, coal, etc.); (4) negligible or low fluid flow, and not ground-water discharge area; and (5) low seismic risk.

The criteria used in a regional evaluation are perhaps best discussed by application to an example. For this purpose, the entire conterminous United States can be subjected to a superficial evaluation (Warner and Lehr, 1977).

Synclinal sedimentary basins and the Atlantic and Gulf Coastal Plains (Figure 8.2) are particularly favorable sites for Class I wells. They contain relatively thick sequences of salt-water-bearing sedimentary rocks and the subsurface geology of these basins is well known. Other areas may be generally unfavorable as sites for injection because sedimentary-rock cover is absent or thin. Extensive areas where relatively impermeable igneous-intrusive and metamorphic rocks are exposed at the surface are shown in Figure 8.2; with the possible exception of small areas, these can be eliminated from consideration for injection. The exposure of igneous and metamorphic rocks in the Arbuckle Mountains, Wichita Mountains, Llano and Ozark uplifts, south of the Canadian Shield, and others are not extensive, but are significant because the sedimentary sequence thins toward them and the salinity of the formation water decreases toward the outcrops around them.

Regions shown in Figure 8.2 where a thick volcanic sequence lies at the surface generally are not suitable for Class I injection wells. Although volcanic rocks have fissures, fractures, and interbedded gravel that will accept injected fluids, they generally contain fresh water.

The immense and geologically complex Basin and Range Province is a series of narrow basins and intervening, structurally positive ranges. Some of the basins might provide injection sites, but their geology is mostly unknown.

The geology of the West Coast is relatively complex. Small Tertiary sedimentary basins in southern California yield large quantities of oil and gas, and probably are geologically satisfactory sites for Class I injection wells. There are similar basins along the coast of northern

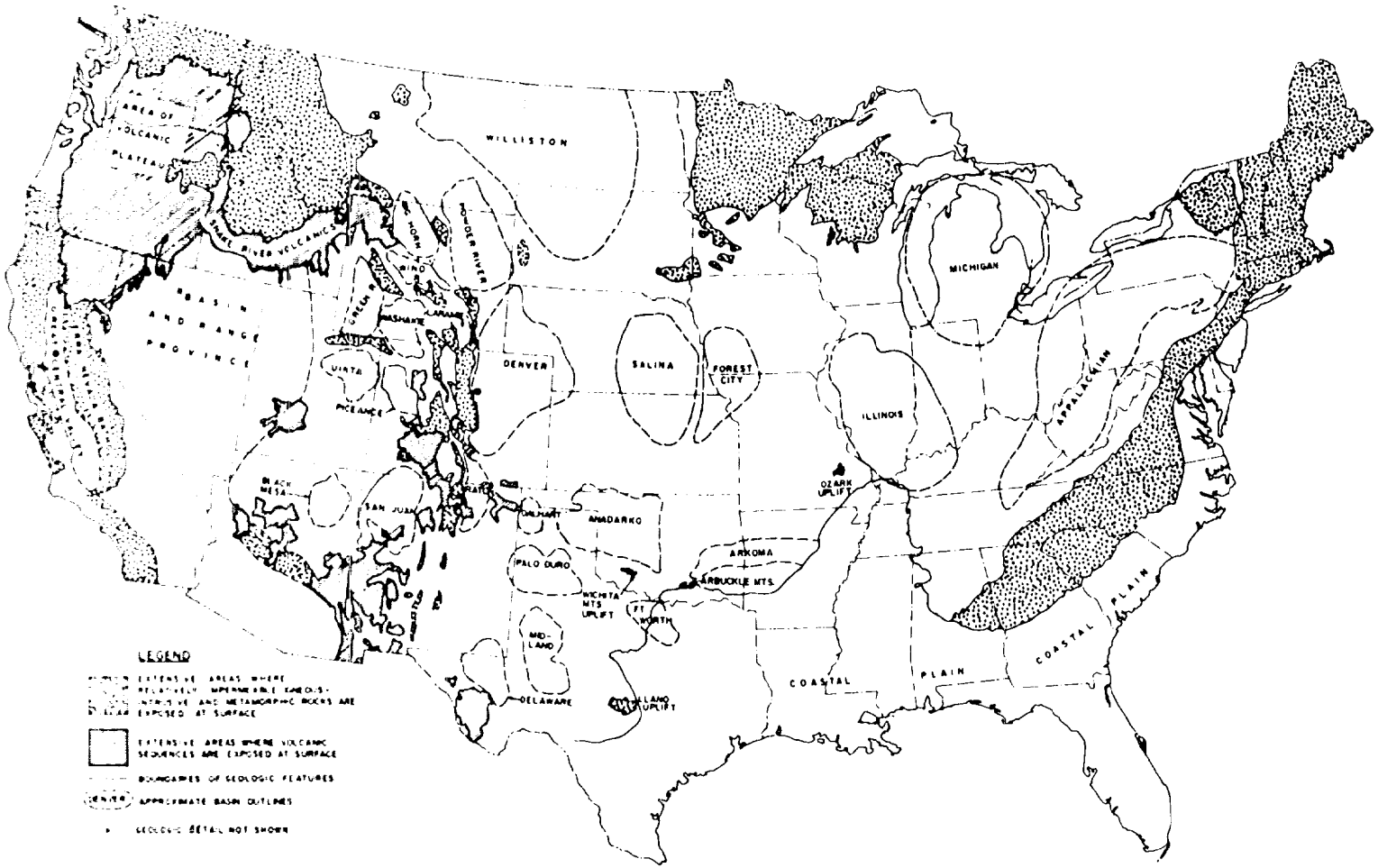

Figure 8.2. Geologic features significant in evaluation of Class I injection-well siting (Warner, 1968)

California, Oregon, and Washington, but little is known about their geology.

Areas not underlain by major basins or prominent geologic features may be generally satisfactory for Class I injection wells if they are underlain by a sufficient thickness of sedimentary rocks that contain saline water, and if potential injection zones are sealed from fresh-water bearing strata by impermeable confining beds.

Local Site Evaluation

Factors for consideration in local site evaluation are listed in Table 8.1. Figure 8.3 is a flow diagram that illustrates the local site evaluation procedure, but should not be considered a rigid format.

Briefly, a potential injection site and injection zone should have the following characteristics: (1) sufficient thickness, with adequate porosity and permeability to accept liquid at the proposed injection rate without necessitating excessive injection pressures; (2) preferably homogeneous (without high-permeability lenses or streaks); (3) large enough areal extent to minimize injection pressure and prevent the injection fluid from reaching discharge areas; (4) overlying and underlying strata (confining beds) sufficiently thick and impermeable to confine liquid to the injection; (5) generally simple structural geologic conditions (i.e., reasonably free of complex faulting and folding); (6) area of low seismic activity and minimal earthquake damage; (7) slow lateral movement of fluid in the injection zone to prevent rapid movement of waste away from the injection site; (8) formation-fluid pressure low to normal to limit rates of undesirable reactions (e.g. corrosion); (10) injection fluid compatible with formation fluids and minerals; (11) formation water of no apparent economic value (i.e., not potable, unfit for industrial or agricultural use, or not containing minerals in economically recoverable quantities); (12) adequate horizontal and vertical separation from potable water zones; (13) will not endanger present or future mineral resources (e.g. coal, oil, gas, brine); (14) will not affect existing or planned gas-storage or fresh-water storage projects; and (15) no unplugged or improperly abandoned wells penetrating

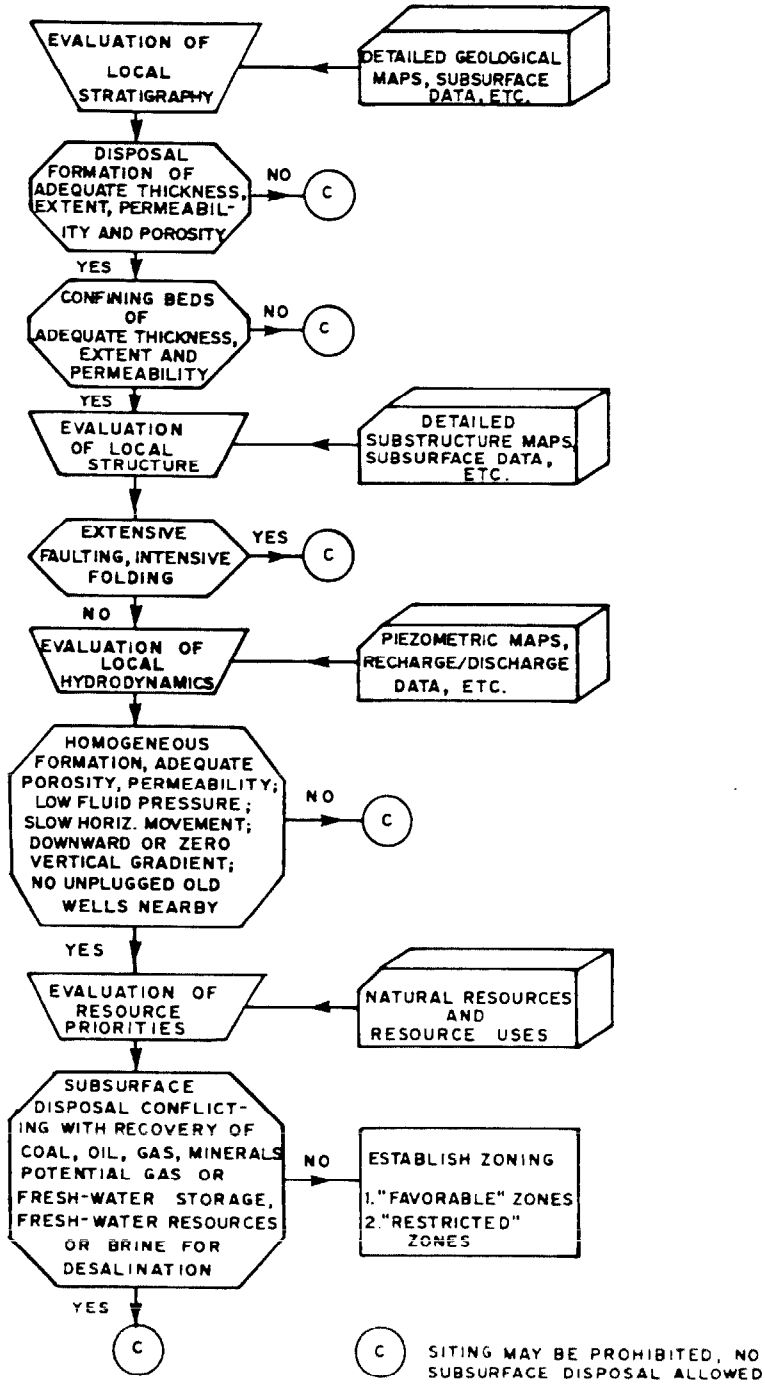

Figure 8.3. Methodology to make site-specific evaluation of suitability for Class I injection wells (van Everdingen and Freeze, 1971)

the disposal formation in the vicinity of the injection site.

More detailed geologic and engineering properties are examined at the local level than at the regional level. As illustrated, in a regional examination one objective is to identify an adequate thickness of rocks for an injection zone and confining strata. At the local level, the objective is to identify specific potential injection zones and confining strata and to predict their performance under projected operating conditions. This same rationale applies to other criteria, such as structural geology, hydrodynamics, and subsurface resources.

The procedure for local evaluation of an injection-well site should first provide documentation of the results of the analysis of the items listed above prior to drilling a well. Then, if the site is suitable for construction, each item should be reanalyzed as information is obtained during drilling and testing. The final decision whether injection is feasible or not is based on the sub-surface data that have been acquired during drilling and testing and which have been used to project the response to sustained injection of the subsurface geologic and hydrologic system.

8.1.3 Well Design

It is difficult to identify design features that can be considered typical for Class I industrial waste-disposal wells, since these wells differ greatly according to their purpose and location. All such wells have some common features and are drilled in a similar way, but the individual well is specially designed to deal with local hydrogeologic conditions, unusual types of wastes, or unique chemical reactions.

The problems associated with waste and formation compatibility have received considerable attention (Donaldson, 1972; Sadow, 1972; and Hower, et al., 1972). These problems can be categorized as waste fluid and formation fluid interactions. These may lead to a severe reduction in formation permeability or to a loss of structural integrity within the formation itself. Waste and formation compatibility problems are specific to the particular

formation and waste involved. Their prediction and solution require site-specific studies. Specific problems associated with such compatibility include plugging of the injection formation with suspended solids, precipitation and polymerization of the waste fluid, growth of biologic organisms within the formation, and dissolution of the formation matrix.

In some cases, the injection fluid may react directly with the rock matrix. One common problem is the swelling of clays from contact with the injection fluid. Affected clays can significantly reduce the permeability of the formation. In other instances, polar-organic compounds can be adsorbed by the rocks, particularly silicates, and can significantly reduce the permeability of the formation.

The injection of acids may result in dissolution of the rock matrix. In the case of certain cemented material, dissolution can result in the migration of particles which then block pore spaces and reduce permeability.

Many of the wastes injected into industrial waste-disposal wells are highly corrosive and require special consideration during the design of all aspects of a disposal system. Generally, corrosive wastes are injected through a tubing string placed inside the well casing. Corrosion-resistant metal alloys may be used but the use of fiberglass-epoxy tubing has been more popular because of its greater resistance to corrosive materials. For further protection against corrosion, the annular space may be filled with a corrosion-inhibiting solution.

Several examples of industrial waste-disposal wells are presented below, selected to cover basic differences in design by site-specific conditions and disposal needs.

Injection wells used since the mid-1950s by a northern Florida facility which manufactures nylon have received considerable attention (Batz, 1964; Dean, 1965). The facility is one of the original industrial waste-disposal systems developed and operated in the United States, and provides an interesting case study identifying early construction features and the problems first encountered in the construction and the operation of disposal wells. The waste system associated with the manufacture of nylon consists of

a dilute aqueous solution of organic acids, alcohols, keytones, esters, mineral acids, and inorganic salts.

The original idea of waste injection developed from a written report on the local subsurface geology and groundwater resources which identified a number of limestone formations containing saline water at a depth of approximately 1,400 feet (427 m), overlain by a dense clay layer approximately 200 feet (61 m) thick. A schematic diagram of the geological formations encountered is presented in Figure 8.4.

The well was designed with an 18 inch (5.7 cm) diameter carbon-steel casing cemented to the upper Floridan limestone, below which a 12 inch (30 cm) diameter carbon-steel casing was cemented into the upper layers of the lower Floridan limestone unit. An 11-7/8 inch (30.2 cm) bit was used to drill out the remaining 200 (61 m) feet of the lower limestone unit. An open hole configuration was used to complete the well.

The original well design called for an 8 inch (20.3 cm) diameter stainless-steel tubing set in a packer in the bottom of the well. However, when the stainless-steel tubing was installed the packer failed to seat properly, and to avoid pulling the liner back out of the hole, an alternative design was implemented to fill the annular space with diesel oil pumped under pressure to prevent formation water from entering the annulus. Several problems arose during installation and completion of the well which were overcome by trying different procedures. Shortly after operation began, for example, a power failure occurred, shutting down the pumps and resulting in the loss of the entire charge of oil in the annulus through the top of the well. Attempts to reestablish the column of oil in the annulus proved unsuccessful. The tubing was pulled out of the hole, and was found to have collapsed. A new injection tubing of smaller diameter and greater structural strength was placed in the hole and the packer was repaired so that it seated correctly. In addition, a 3/4 inch (1.9 cm) pipe was placed in the annulus between the tubing and packer, extending from the surface to just above the packer, to continually monitor the annular fluid at the bottom of the hole.

The injection well has operated successfully for a number of years, and a second well was constructed in

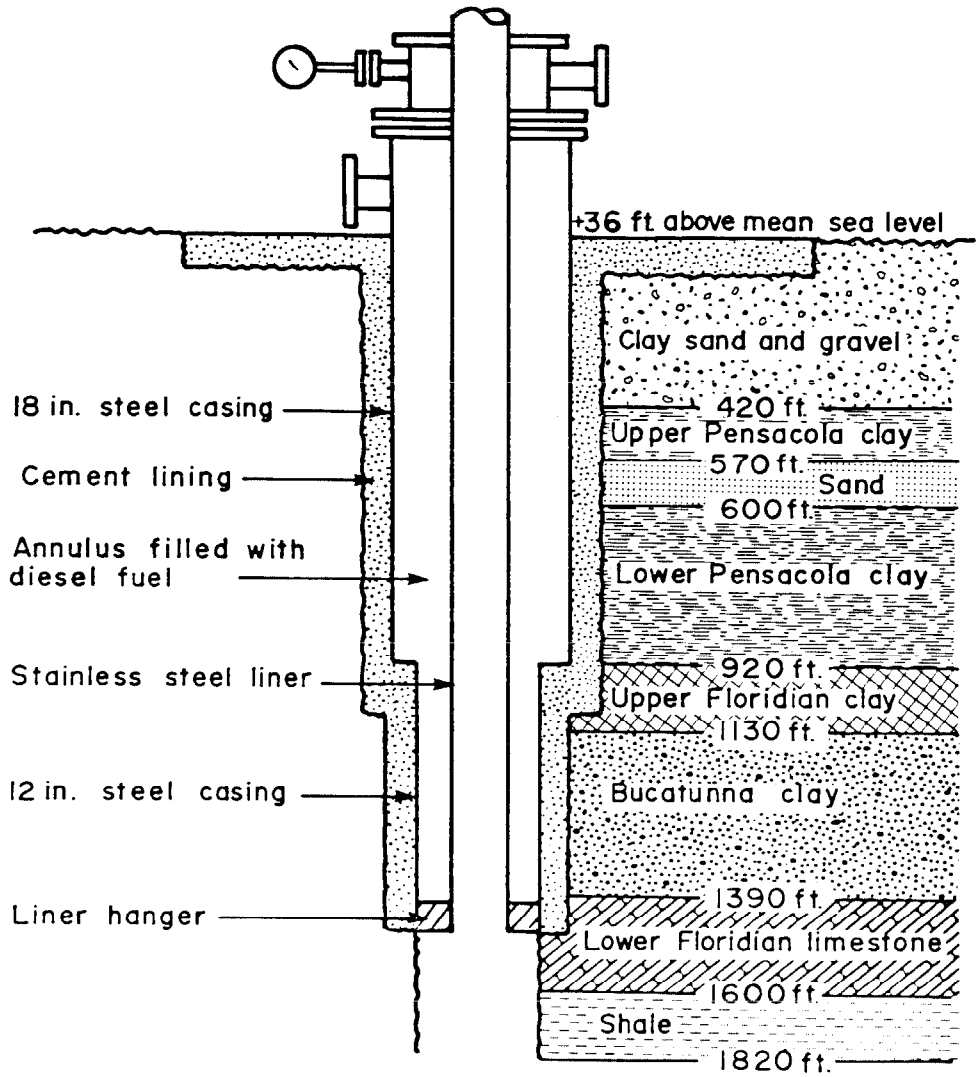

Figure 8.4. Schematic diagram of Class I injection well showing geology (Batz, 1964)

1965 to accommodate the disposal of greater amounts of wastes. Injection rates have risen from 600 gallons per minute (gpm) (37.8 lps) in 1963 to 2,100 gpm (132.3 lps) in 1971. Over the years, injection pressures have dropped while increasingly greater amounts of wastes have been pumped into the deep aquifer indicating probable dissolution of the injection zone.

A second example of an industrial waste-disposal well is one used for disposal of spent pickling liquors at a steel plant near Gary, Indiana (Bayazeed and Donaldson, 1973; Hartman, 1966; Smith, 1969). This facility disposes of 151 gpm (9.5 lps) of waste effluent composed of a mixture of iron salts, residual acid, and water. The waste is a highly corrosive, toxic liquid which requires neutralization, producing a large quantity of salt.

Construction details of the Gary, Indiana, well are shown in Figure 8.5. A 16 inch (40.6 cm) construction casing was used to stabilize the hole during drilling and subsequent operations. Potable water occurs at the site only in the surficial glacial drift which extends to a depth of 175 feet (53.3 m). This aquifer was isolated by setting a 13-3/8 inch (33.9 cm) surface casing into a 17-1/2 inch (44.4 cm) diameter hole drilled to a depth of 128 feet (39 m) below the fresh-water aquifer. The borehole was continued below the surface casing using a 12-1/4 inch (31 cm) diameter bit into the upper portion of the Eau Claire Formation to a depth of 2,703 feet (823.9 m). The hole was cased with a 9-5/8 inch (24.4 cm) casing and cemented back to the surface. The borehole was extended through the Eau Claire Formation using a 8-1/4 inch (20.9 cm) diameter bit to a depth of 3,257 feet (992.7 m). Penetrating just inside of the Mt. Simon Formation, the borehole was cased and cemented back to the the surface using a 7 inch (17.8 cm), J-55, 23 pound (34.2 kg/m) casing. The well was completed with a 6-7/8 inch (17.5 cm), open hole drilled to the basement granite, exposing 1,611 feet (491 m) of Mt. Simon Formation sandstone for injection.

Throughout the drilling program, drill cuttings and cores were taken at intervals. These samples, along with geophysical logs, were analyzed to determine the characteristics of the geologic strata penetrated by the well. The core samples were examined for a variety of formation

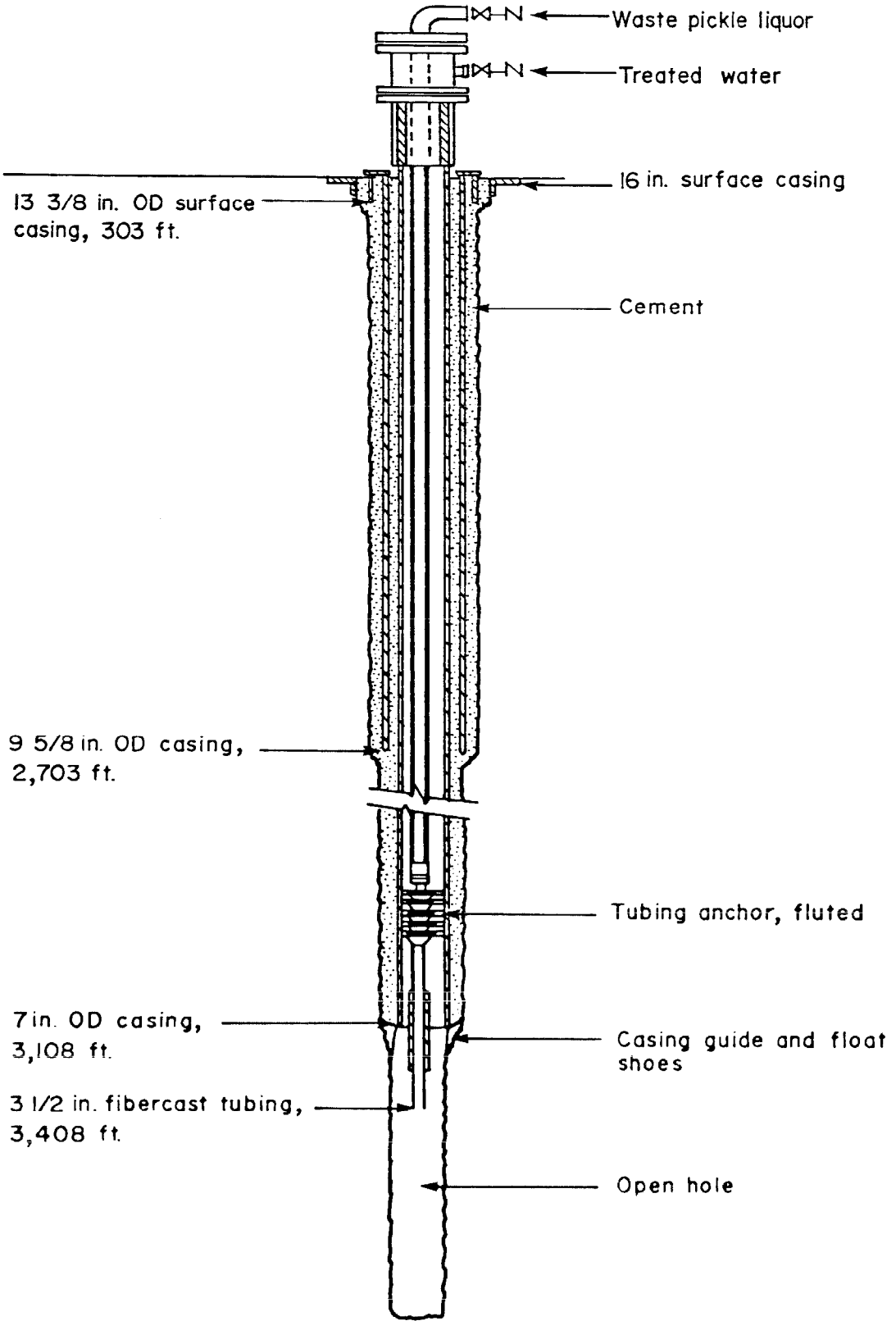

Figure 8.5. Schematic diagram of Class I injection well at Gary, Indiana (Bayazeed and Donaldson, 1973)

characteristics, including permeability, porosity, and solubility.

Compatability tests were run using a sample of the waste pickle liquor. It was found that the formation in the injection zone contained bentonitic or montmorillonitic clay minerals that reacted immediately with the waste fluid, resulting in a decrease in formation permeability. The loss of permeability was not judged great enough to significantly hinder the waste-injection operation. Tests also indicated that dissolution of the sandstone cements would occur with time and possibly result in an increase in formation permeability.

After completion of drilling and sampling, the hole was cleaned of drilling fluid and a temporary injection tubing was set in a retrievable packer. Injectivity testing was performed using filtered, processed water treated with a biocide. After the well-performance tests were completed, the temporary tubing and packer were removed. A 3-1/2 inch (8.9 cm), Fibercast tubing was then set on a fluted tubing anchor. The anchor allows flow of fluid through the annulus between the tubing and casing so that a hydraulic seal can be maintained. Water was pumped through the annulus at a sufficient pressure to prevent the injection fluid from entering the annulus.

After two years of operation, the injection facility was found to be working as designed. The waste fluid is filtered prior to injection, and the water injected through the annulus is treated with a biocide to prevent bacterial growth on the exposed surface of the injection zone. No reduction in permeability beyond that observed during the initial injectivity testing has been noted. Also, no increases in permeability have been detected.

8.2 MUNICIPAL DISPOSAL WELLS

Municipal-waste disposal wells are not nearly as numerous as industrial-waste disposal wells. The basic location, design, and operation issues are, however, applicable to both types of wells.

8.2.1 Description of the Practice

Increasingly stringent controls on discharges of sewage effluents into surface-water bodies have forced municipalities to look for more effective means of waste treatment and disposal. In many areas of the country including Florida, Hawaii, Louisiana and Texas, municipalities have turned to the use of injection wells for the disposal of sewage effluents. Currently the largest and most sophisticated wells are used in Southern Florida where the favorable hydrogeology makes the use of wells for subsurface injection of wastes appropriate (Garcia-Bengochea and Vernon, 1970; Kaufman, 1973).

South Florida is underlain by a series of ground-water bearing strata of cavernous limestones and dolomites separated by thick and impervious layers of marls and dense limestones. Ground water in the deeper strata, generally at depths greater than 1,500 feet (457 m), is highly mineralized. At a depth of approximately 3,000 feet (914 m), a particularly permeable bed of highly fractured cavernous dolomite exists. This zone is called the Boulder Zone because oil-well drillers have reported fractured dolomite fragments (boulders) falling into boreholes during drilling. Water quality is poor at this depth, and the zone has an extremely high permeability and the capacity to receive large amounts of waste under low injection pressures. Consequently, a number of injection-wells have been constructed in the area in the past decade.

8.2.2 Well Design

A municipal waste-disposal facility was constructed in West Palm Beach, Florida, in the mid-1970s (Amy, 1980). Development of this facility was motivated by a request to consider alternate means of waste disposal other than ocean outfall from EPA to the City of West Palm Beach.

The presence and character of the Boulder Zone had not been verified in the West Palm Beach area. Consequently, a program to explore the subsurface hydrogeology and to install a test-injection well was initiated. The test-injection well was drilled, cored, geophysically logged, and pump tested. The tests revealed that the Boulder Zone was approximately 350 feet (106.7 m) thick at the site and

occurred at a depth of 3,150 feet (960.1 m). The zone was highly transmissive and pumping tests indicated that bottom-hole driving pressures of 6 to 12 psi (4.1×10^4 to 8.2×10^4 N/m^2) would result in injection rates of 7,000 to 10,000 gpm (441 to 630 lps).

The use of injection wells for the disposal of the waste-water effluent of the city was determined practical, and the city embarked on a program to construct a well system. A two-phase construction program was used. The initial phase called for a treatment capacity of 20 million gallons per day (mgd) (7.56×10^4 m^3/d) and for injection into three 24 inch (61.0 cm) diameter wells. Each well was designed for an average disposal rate of 11 mgd (4.16×10^4 m^3/d) and a peak injection rate of 22 mgd (8.3×10^4 m^3/d). Two wells were to operate simultaneously, with the remaining well acting as a stand-by. The second phase called for expanding the plant to 44 mgd (1.66×10^5 m^3/d) with the addition of two similar wells.

A diagram of a typical disposal well installed at this site is shown in Figure 8.6. Four strings of casings were used, the first set to a depth of about 100 feet (30.5 m) to provide protection from washout and collapse during drilling and subsequent operations. A 48 inch (1.2 m) diameter surface casing was set to approximately 400 feet (121.9 m) to seal off the fresh-water aquifer and a 36 inch (0.9) m diameter intermediate casing was set to a depth of approximately 1,000 feet (305 m). The inner or injection casing was set into the lower portion of the confining layer to a depth of approximately 3,000 feet (915 m). A 24 inch (61.0 cm) seamless or electric-resistance welded pipe with a wall thickness of 0.375 inches (.9 cm) was used for the inner casing. The bottom-hole completion was of an open-hole configuration.

All casings were completely cemented in place to provide additional protection for longer life. Because of the thin walled casing and its large diameter, cementing had to be performed with caution to prevent collapse. The cementing was done in stages and the casings were pressurized to prevent collapse. Cement was pumped through the drill pipe from the lower portion of each casing to fill the annulus from the bottom up. Upper portions of the casing were cemented through a tremie pipe set in the annulus.

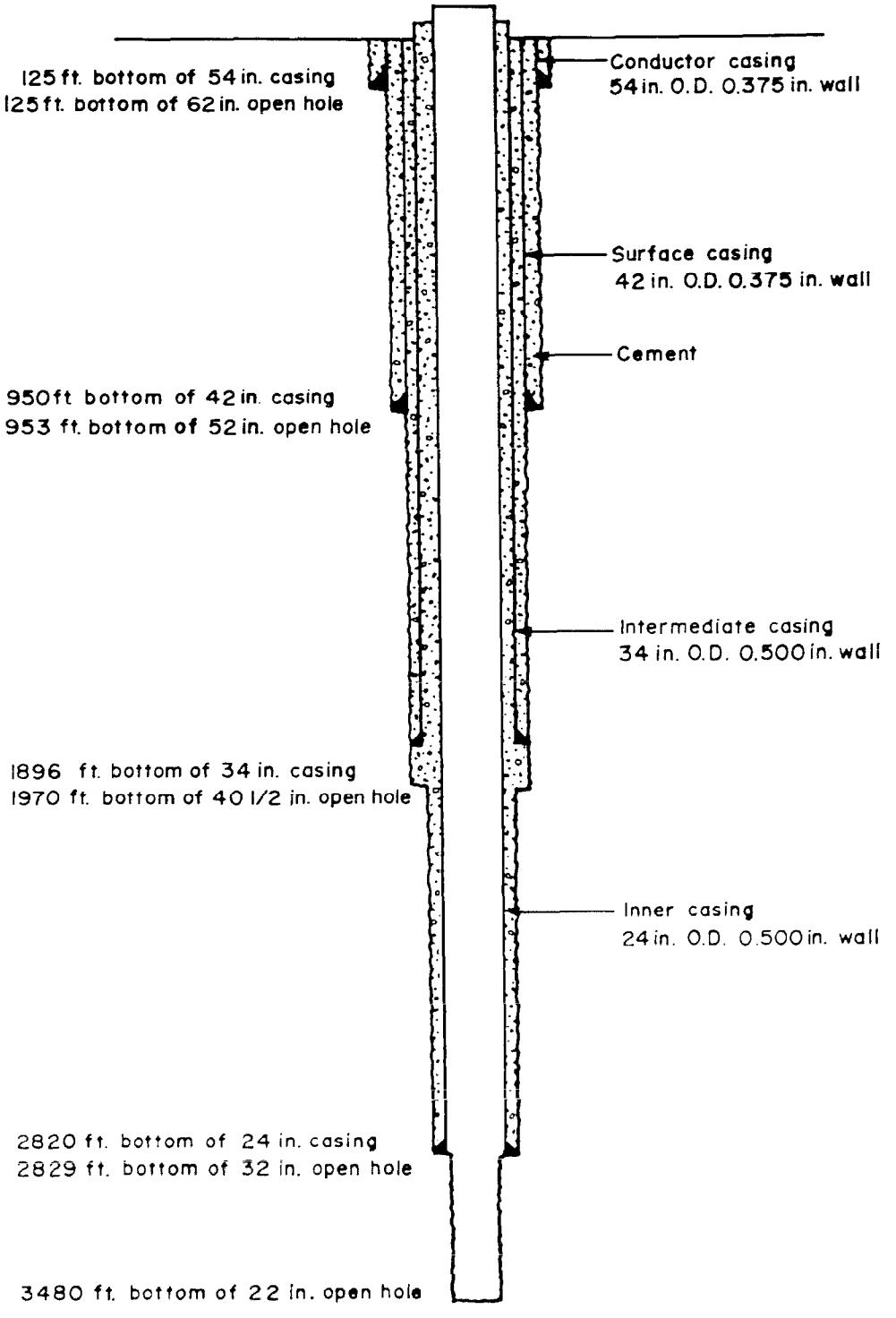

Figure 8.6. Schematic diagram of Class I injection well at West Palm Beach, Florida (Amy, 1980)

The Florida Department of Environmental Regulation required monitoring of the salt-water bearing zone above the top of the confining strata with either separate monitoring wells or annulus monitoring tubes. Annulus monitoring was selected as the least costly alternative. A zone between 2,000 and 2,300 feet (609.6 and 701.0 m) was designated for monitoring because it was sufficiently permeable to produce salt water. In each well, a 2 inch (4.9 cm) steel pipe was set inside the annulus between the 24 inch (61.0 cm) casing and the wall of the borehole to serve as a monitoring tube. Identification of the appropriate depth settings was accomplished using geophysical logs and drilling records. The monitor tubes and cement sheaths were directionally perforated with explosive charges to assure communication with the formation. In some instances it was necessary to stimulate the monitoring zone using an inhibited, 15 percent solution of hydrochloric acid.

An extensive suite of geophysical logs was run in each well during construction, including induction and lateral, gamma ray, caliper, variable density, temperature, neutron, sonic, and denisty logs. After completion, cement-bond logs and pressure tests were run within casings, and the wells were surveyed using downhole television equipment. Video tapes were made and preserved for future reference. Directional surveys were performed during drilling to insure a straight hole.

The injection facility started operation in December 1977, disposing of an average of 10 mgd (3.78×10^4 m^3/d) of sewage, with peak injection rates of 10,000 gpm (630 lps). Prior to injection, the static water level in the wells was about 15 feet (4.6 m) below land surface. After injecting for some period of time, a bubble of fresh water accumulated in the injection formation around the wells, resulting in a shut-in pressure at the well head of 28 to 30 psig. These pressures, generated by the density differential between saline formation water and the injected fresh-water effluent, represent a major component of the total head required for injection. The remainder of the head is needed to overcome friction loss occurring during fluid flow down the casing and into the injection formation. Pressure records taken from one well during the initial phase of operation indicated a shut-in pressure of 30 psig (2.07×10^5 N/m^2) and an injection pressure of 43 psig (3.0×10^5 N/m^2) with an injection rate of 10,500 gpm (662 lps).

By 1980, this facility was disposing of 20 to 22 mgd (7.56×10^4 to 8.3×10^4 $m/^3d$) of sewage effluent. Peak injection rates were as much as 25,000 gpm (1,577 lps) with three wells in operation, and injection pressures were between 40 and 50 psig (2.76×10^5 and 3.4×10^5 N/m^2). An extensive program of monitoring has been conducted, with samples taken continuously from each annular monitor tube using a small centrifugal pump. The conductivity of this fluid has been recorded on strip charts, and periodic chemical analyses have been made for chlorides, total Kjeldahl nitrogen, sulfates, pH, total organic carbon, hydrogen sulfide, fecal coliform, and total coliform. No change in character of the monitor zone fluids has been observed.

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9. CLASS II INJECTION WELLS

Class II injection wells are used for the disposal of salt water, for enhanced oil recovery, and for subsurface storage of liquid hydrocarbons. In a basic sense, they are designed, constructed, and operated similarly to Class I wells, but with major distinctions involving the use of special construction materials and special techniques to reduce failure. During enhanced oil recovery, for example, the high temperatures generated by in-situ combustion can cause the development of strong tensile and compressive forces and can warrant the use of high strength casing. The following discussion highlights the characteristics, design, and construction methods used to complete different types of Class II injection wells. The different types of Class II injection wells to be included under the UIC program are associated with several oil field operations as shown in Table 9.1.

9.1 SALT-WATER DISPOSAL

9.1.1 Description of the Practice

In oil and gas production, salt water is frequently produced which must be disposed of. The most common method of salt-water disposal is subsurface injection which may be integrated with an enhanced oil recovery strategy. The chemical composition of oil-field salt water (brine) differs considerably from one geologic formation to another. The major constituents of brine are sodium and calcium chloride, but may also include magnesium, bicarbonate, and sulfate ions. Concentrations of anions and cations in the salt water can range from less than 100 to more than 100,000 ppm as shown in Table 9.2 (Donaldson, 1979).

Salt water can be disposed of through a well specifically drilled for disposal, through a converted oil or gas production well, or through a dry hole. When necessary, the brine is treated prior to injection to control corrosion and prevent plugging of the formation. An overview of such pretreatment is discussed in Chapter 6. Injection is accomplished either by gravity flow or by pumping the salt water through a cased and cemented well. Generally, the

TABLE 9.1
CLASS II INJECTION WELLS

Salt water dispoal

Enhanced oil recovery

- Water Flooding
- Thermal processes
  - -Steam flooding
  - -In-situ combustion
- Chemical processes
  - -Polymer flooding
  - -Caustic flooding
  - -Surfactant flooding
- Miscible displacement processes
  - -Miscible hydrocarbon displacement
  - -Carbon dioxide injection
  - -Inert gas injection
  - -Other gases such as hydrogen sulfide

Liquid hydrocarbon storage

TABLE 9.2
ANALYSIS OF NATURAL BRINES SHOWING
MAJOR CONSTITUENTS (ppm)
(Donaldson, 1970)

Type of Brine	Formation	Location	Na	Ca	Mg	Cl	HCO_3	SO_4
Sodium chloride	Big Injun	PA	52,200	1,730	3,910	121,000	70	320
Sodium carbonate	Ellis	MT	3,140	90	80	2,890	4,040	820
Sodium sulfate	Coalinga	CA	3,290	390	340	2,520	360	7,260
Calcium chloride	Arbuckle	KS	4,230	6,900	8,430	60,100	42	1,190
Calcium carbonate	Embar	WY	140	140	30	10	210	190
Calcium sulfate	Madison	WY	580	870	180	1,070	1,080	1,940
Magnesium chloride	Lodegepole	Manitoba	44,900	3,260	67,340	94,900	2,140	4,800
Magnesium carbonate	Unita	CO	450	428	542	90	1,185	1,038
Magnesium sulfate	--	NM	100	1,000	25,000	9,000	0	60,000

best formations for injection are pressure-depleted aquifers or depleted oil-producing zones (API, 1978).

9.1.2 Well Design

Commonly, Class II injection wells are completed as open hole, perforated casing, or perforated liner. In unconsolidated formations, a screened and gravel packing completion may be used.

Major problems encountered during salt-water disposal involve the formation of precipitates and the deposition of scale on the formation, reducing the permeability of the injection zone and inhibiting injection. The use of a pretreatment system can control this problem.

Other problems result from well design and construction, especially corrosion of materials when converting a former production well into an injection well. Corrosion in salt-water disposal wells can occur both internally and externally. Internal corrosion is primarily a result of oxygen in the injection fluid contacting the casing or tubing. External corrosion is caused by oxygen or by sulfate-reducing bacteria in the environment surrounding the well. If the salt water also contains carbonates and/or hydrogen sulfide, the rate of corrosion can be greatly accelerated.

Internal corrosion in salt-water disposal wells can be controlled by removing the oxygen from the brine or by adding corrosion inhibitors such as bactericides to eliminate sulfate-reducing bacteria. Oxygen removal is is accomplished by a treatment system; however, if such systems are too costly, use of materials such as plastics or cements to coat the casing to eliminate contact with the oxygen-bearing brine could be considered (API, 1978). However, pinholes can develop in the coatings and can permit corrosion to occur. Stainless steel alloys also have a greater resistance to oxygen corrosion than other carbon-steel materials and are frequently more useful than coating. A more successful method of controlling corrosion is to utilize a tubing string, preferably of fiberglass-epoxy resin, run through the center of the well casing to transport injection fluids from the wellhead to the injection zone. For this type of well completion even greater pro-

tection against corrosion is afforded by isolating the annulus between the tubing and injection casing. This is accomplished by setting a packer at the bottom of the borehole between the tubing and the casing to seal off the annulus from the injection zone. The annulus then can be filled with an aqueous solution containing a corrosion inhibitor. Placing the annulus under observation (either pressure or fluid flow) also enables monitoring for leakage (Donaldson, 1979).

Conversion of an oil or gas production well to a salt-water disposal well is common in oil-field operations. Often it is less expensive to convert a depleted well or a dry hole than to drill a new well. In addition, the mechanical condition of an existing well, including casing, cementing, and choice of the injection zone, may be ideally suited for salt-water injection. In other instances, the well may be in poor condition (inadequately cased or cemented) to function safely as a disposal well (Bachman, 1980). This may be particularly true in the conversion of a dry hole (i.e. a well drilled and not completed for production) to a disposal well (API, 1978).

Conversion of an oil or gas production well to a salt-water disposal well must include a thorough examination of the structure of the existing well and the receptivity of the injection zone. Existing records of the methods of completion of the production well and the nature of the geologic environment may not be adequate to assess the suitability for conversion. Mechanical integrity tests and geophysical logging methods have been established to provide information concerning the structure of the well and to determine what, if any, remedial construction is necessary.

Often the existing well may not have been fully cased or cemented to the surface to provide adequate protection of underground sources of drinking water required during salt-water injection. Squeeze cementing techniques are used in these instances to selectively cement certain zones between the borehole and the casing. Several different types of specialty cements have been developed to facilitate successful squeeze cementing including pozzolan, thixotropic, and expanding cements.

9.2 ENHANCED OIL RECOVERY

9.2.1 Description of the Practice

Enhanced oil recovery encompasses a broad spectrum of technologies designed to increase the yield of crude oil from existing reservoirs. The technologies vary from conventional secondary recovery techniques, such as water flooding, to more sophisticated tertiary recovery methods such as polymer or surfactant flooding. However, all of the enhanced oil recovery methods do have a singular common feature; that is, the utilization of a well to provide a means of injecting a liquid or a gas into the formation to produce a drive mechanism to increase oil production. The four principle enhanced oil recovery methods are flooding, thermal processes, chemical processes, and miscible displacement processes.

Enhanced oil recovery methods differ widely in the total quantity of oil produced by each and also in the stage of technological development of each. In addition to water flooding, steam flooding is one of the most widely used methods in the United States [140,000 to 160,000 barrels per day (2.22×10^4 to 2.54×10^4 m^3 per day)] (Dafter, 1980). In California, the number of steam injection wells has risen from 140 in 1966 to 1,630 in 1975 (van Poolen, 1980). Conversely, chemical processes are limited and account for less than one percent of the enhanced oil recovered in the United States (van Poolen, 1980).

Water Flooding

Water-flooding operations utilize the injection of water to restore reservoir pressure or to maintain pressure to increase oil recovery. The source of water for injection is the brine produced with the oil, brackish water from other sources, or fresh water. Injection wells for water flooding are usually installed in a grid pattern, with four injection wells surrounding a production well. During operation, water is pumped into the injection wells and as it moves toward the production well, it forces the oil ahead. Produced water is separated from the oil and re-

cycled for injection. Water flooding will continue until the process is no longer economical.

Thermal Processes

Thermal-recovery methods are used primarily to reduce the viscosity of the oil in place. By adding heat, oil trapped by capillarity in the reservoir is thinned or vaporized and becomes mobile. The oil can then be displaced by injected liquids or gases (van Poolen, 1980). The three types of thermal recovery operations are cyclic-steam stimulation, steam flooding (including hot water flooding), and in-situ combustion (fire flooding). Within the UIC regulatory framework, cyclic steam injection is considered a production-well stimulation method and is not covered in this discussion.

Steam flooding is similar to water flooding except that steam is injected rather than water. Steam is injected into a number of wells arranged in patterns compatible with adjacent production wells. Near the injection wells, the steam forms a saturated zone with a temperature nearly equal to that of the injected steam. As the zone expands toward the producing wells, the temperature drops in response to a pressure decrease; consequently, a series of zones develops as shown in Figure 9.1. In the steam zone, oil is displaced by steam distillation and gas. In the hot water zone, thermal expansion of the oil, reduction in viscosity, reduction in residual saturation, and changes in relative permeability result in oil recovery. In addition, the heat transferred to the reservoir rock can heat cold water subsequently injected into the system and provide an additional recovery mechanism (hot water flood) (van Poolen, 1980; Dafter, 1980).

In-situ combustion or fire flooding involves injecting air into the reservoir and then igniting the oil to generate heat. There are two fundamentally different processes of in-situ combustion, forward combustion (dry combustion) and reverse combustion (as shown in Figures 9.2 and 9.3, respectively). In forward combustion, air is injected and the burning front moves toward the producing well. Typically, temperatures generated at the burning front range from 600°F to 1200°F (315°C to 630°C), causing the lighter fractions of oil ahead of the flame front to vaporize, leaving the heavy, residual coke and carbon deposit

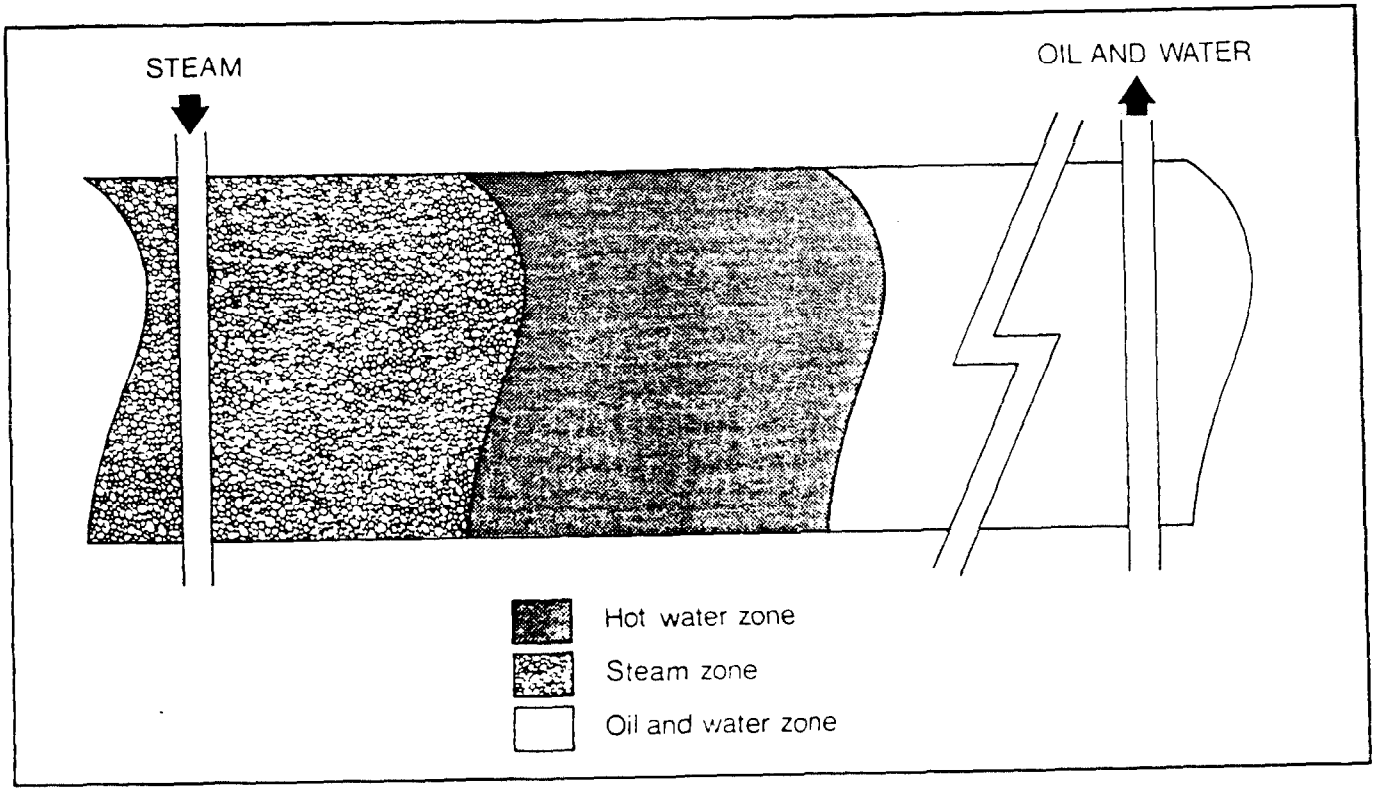

Figure 9.1. Schematic diagram of the steam flood process (Dafter, 1980)

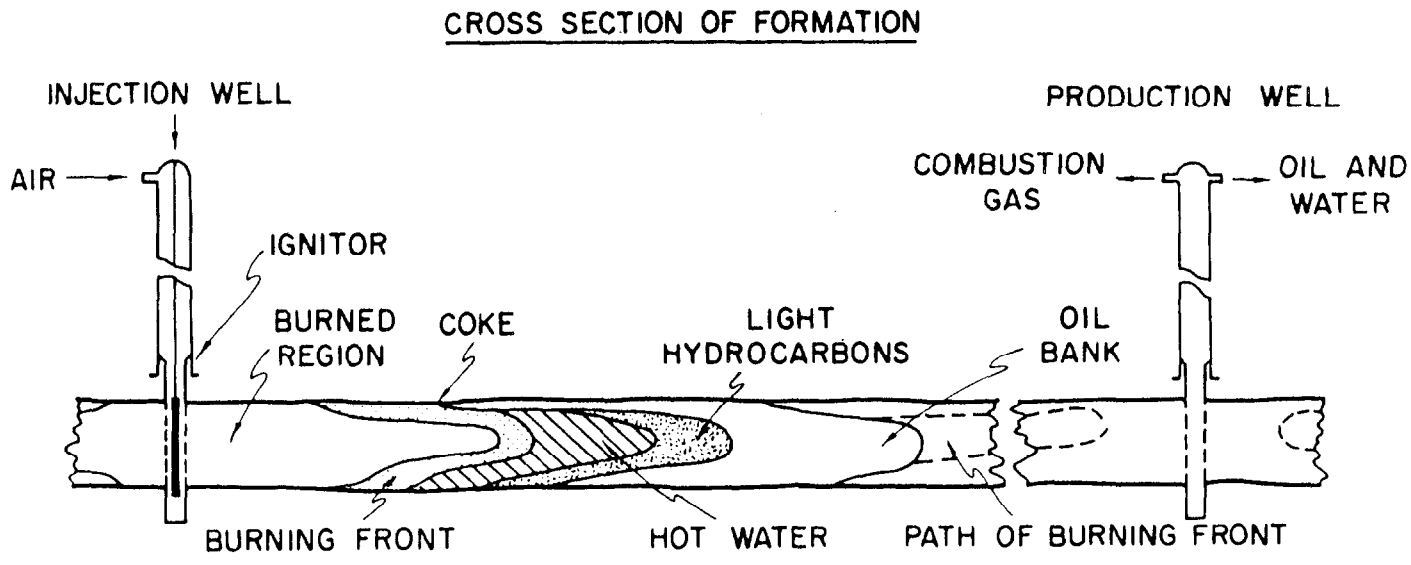

Figure 9.2. Schematic diagram of the forward in-situ combustion process (van Poolen, 1980)

as a fuel. As combustion proceeds toward the producing well, the heated oil is recovered.

Reverse combustion was developed to improve recovery of extremely viscous, heavy crude oil. Like forward combustion, the process is begun by injecting air into the reservoir. After burning out a short distance from the injection well, it is switched to a production well and air injection is continued through an adjacent well causing the flame front to move in an opposite direction to the air flow (Figure 9.3) (Dafter, 1980; van Poolen, 1980).

Chemical Processes

Chemical processes to achieve enhanced oil recovery include some of the most complex and least proved recovery methods. Essentially, chemical enhanced recovery methods are water-flood operations with chemicals added to the injection water to increase the efficiency of oil recovery. Chemical processes consist of three main techniques known as surfactant/polymer or micellar/polymer injection, polymer flooding, and caustic or alkaline flooding. Although commercial applications of these techniques have been undertaken, most of the projects have been directed toward research.

Surfactant/polymer injection involves the injection of surfactants (soap-like chemicals) in combination with polymers. The surfactant lowers the interfacial tension between the oil and the water in the reservoir and thereby mobilizes oil trapped by capillary forces. The purpose of the polymer is to buffer the integrity of the surfactant slug and to provide more effective piston-like displacement of the oil (Gogarty, 1978; van Poolen, 1980). The surfactant/polymer displacement process is shown schematically in Figure 9.4.

Polymer flooding is essentially an improved waterflood technique. Polymers added to injection water are used to increase viscosity, to improve sweep efficiency, and to reduce the total volume of water required to reach ultimate residual oil saturation. The two types of polymers used are polysaccharides and polyacrylamides. Unlike ordinary water which has a tendency to channel through the most permeable parts of the reservoir and bypass large

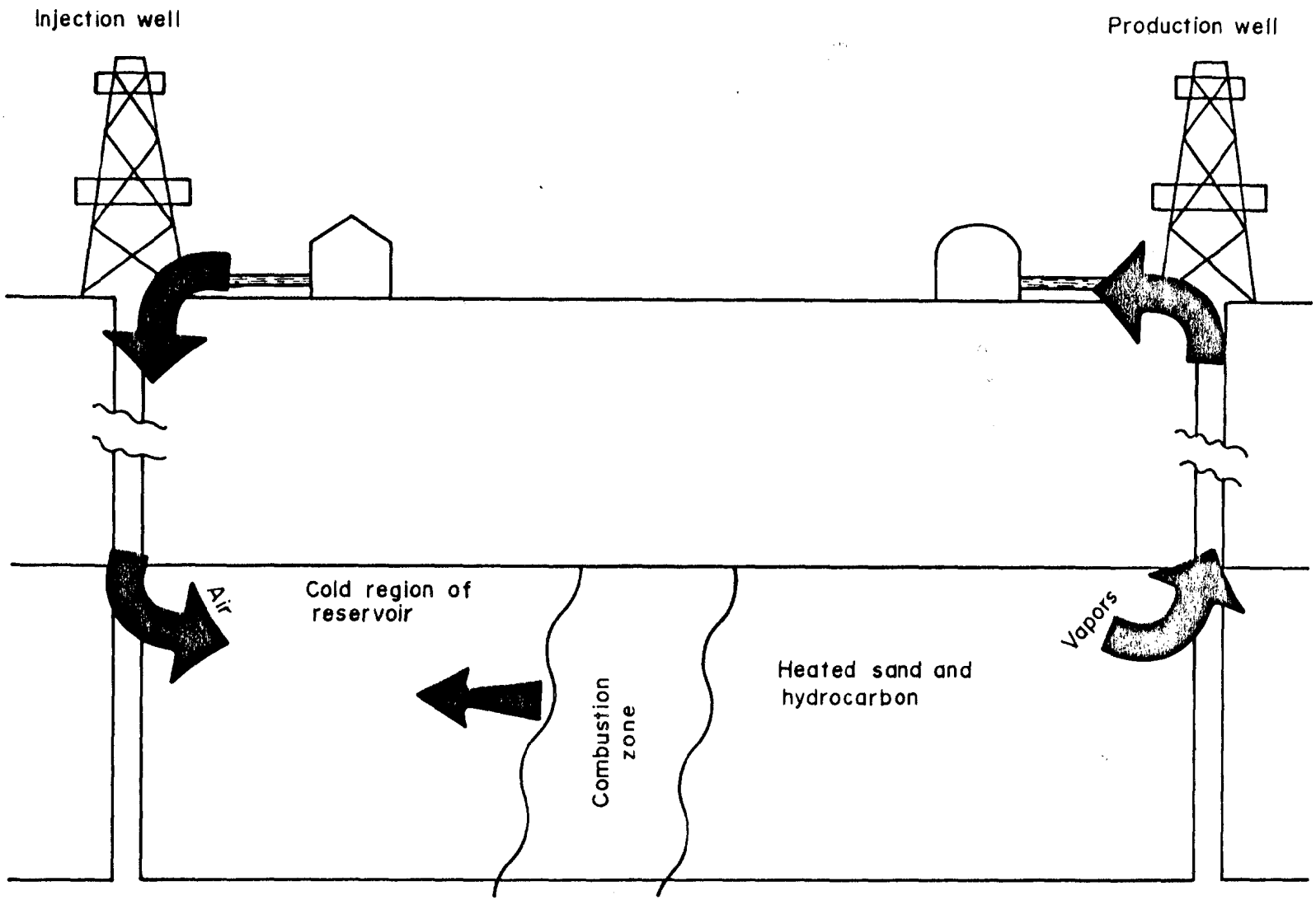

Figure 9.3. Schematic diagram of the reverse in-situ combustion process (van Poolen, 1980)

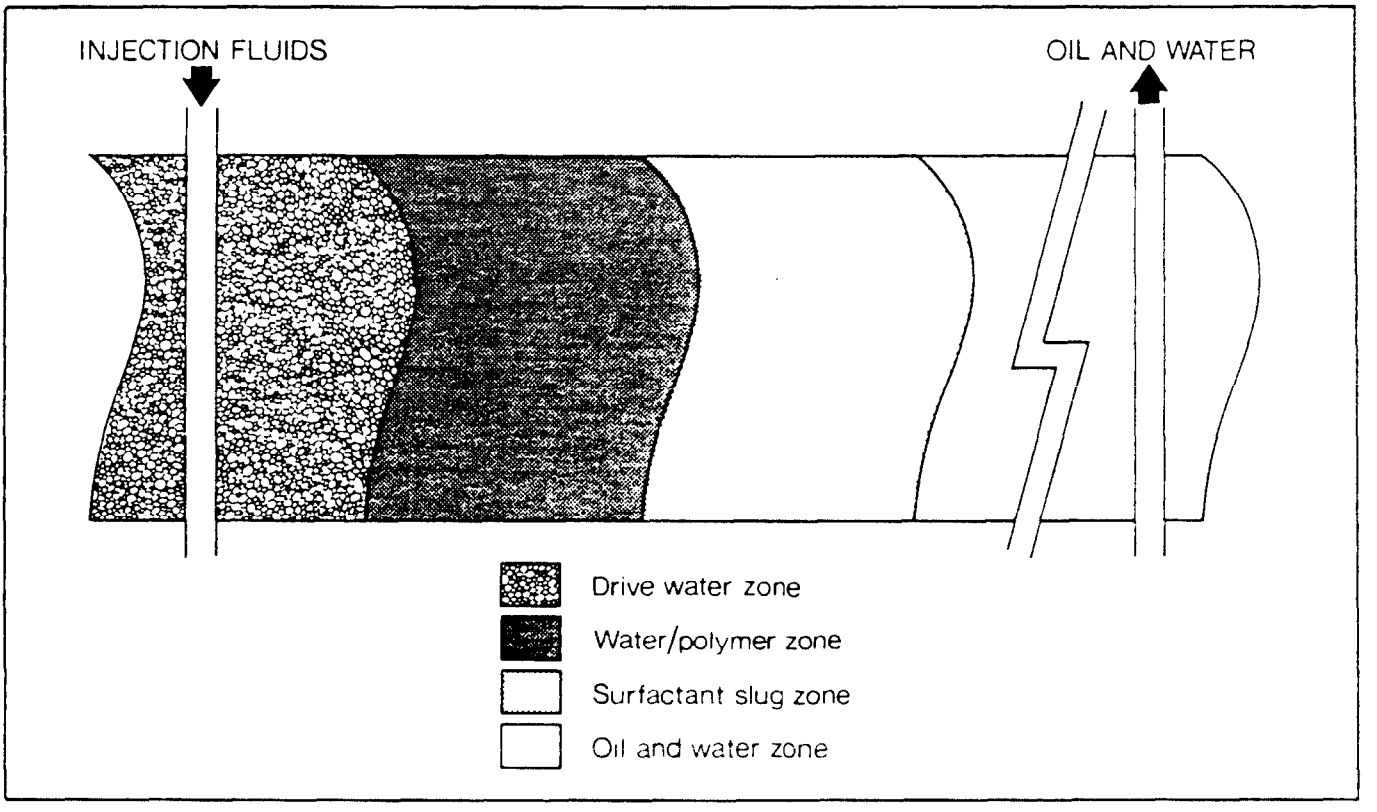

Figure 9.4. Schematic diagram of the surfactant-polymer displacement process (Dafter, 1980)

volumes of oil, the polymer-thickened water is less prone to channeling and is consequently a more efficient pushing agent (Dafter, 1980; van Poolen, 1980).

Caustic or alkaline flooding is a technique which alters the pH of flood water by the addition of chemicals such as sodium hydroxide, sodium silicate, or sodium carbonate. Existing water floods can be easily converted to caustic floods by the addition of 1 to 5 percent sodium hydroxide. Typically the pH of the flood water is maintained between 12 and 13. Although the recovery mechanisms are not well understood, potential lowering of interfacial tension, wettability changes, emulsification and entrapment, emulsification and entrainment, and solubilization the rigid films of the oil-water interface are achieved. All of these processes are thought to relate to the formation of surfactants in the reservoir which arise from the alkaline chemicals neutralizing the acids in the oil in the injection water (Dafter, 1980; van Poolen, 1980).

Miscible Displacement Processes

Miscible displacement processes employ miscible hydrocarbons, carbon dioxide, and inert gas as solvents to dissolve oil, to reduce interfacial tension and capillary forces and to permit increased recovery. Miscible displacement processes were developed in the late 1940s and early 1950s for oil fields containing light crude. Currently, the number of projects involving inert gas injection has grown, while hydrocarbon miscible projects are decreasing due to limited supply and high cost. Carbon dioxide miscible flooding may potentially recover 40 percent of the total projected enhanced oil reserves in the United States (van Poolen, 1980). Figure 9.5 shows the process of carbon-dioxide injection.

During the injection of miscible fluids including hydrocarbons (e.g., naphtha, kerosene, or alcohol), carbon dioxide, or inert gas (nitrogen), oil is dissolved with the solvent to form a single substance; hence, capillary forces are overcome because there is no interface between the oil and solvent. Recovery is completed by following solvent injection with water and/or gas to drive the dissolved substance toward the production well. Pressures in the reservoirs can range from 1,500 psi (1.03×10^7 N/m^2)

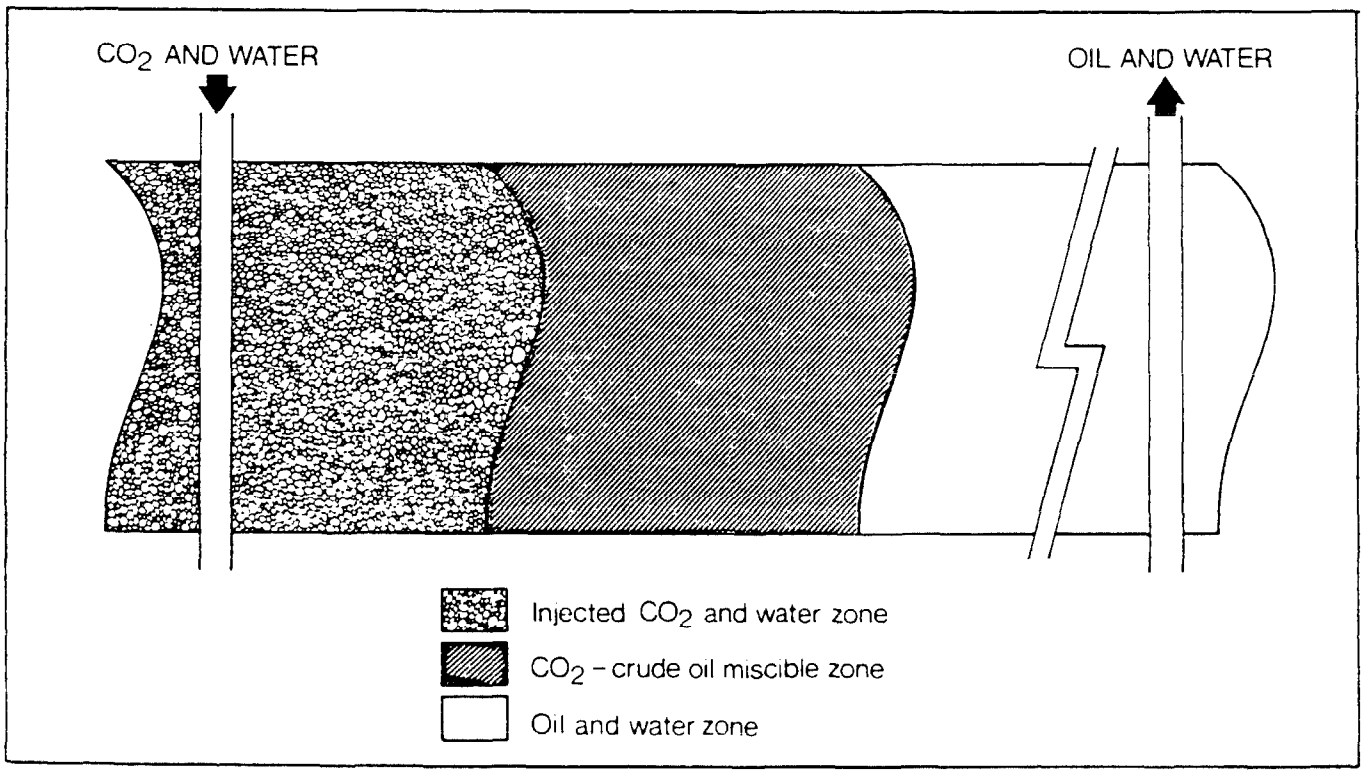

Figure 9.5. Schematic diagram of the carbon dioxide injection process (Dafter, 1980)

for carbon dioxide displacement to more than 4,000 psi (2.76×10^7 N/m^2) for hydrocarbon displacement. As with the other enhanced recovery methods, these processes include injection wells that convey the solvent to the reservoir and that dispose of produced brines (Dafter, 1980).

9.2.2 Well Design

Injection wells used in different enhanced oil-recovery operations are designed to consider such factors as types of injection fluids, temperatures, and likelihood of corrosion. Wells used for steam flooding and in-situ combustion air injection must be designed to withstand high temperatures. Both types are subjected to ambient temperatures during construction that are substantially lower than those encountered during operation. Excessive temperatures generated by steam injection and fire flooding range from 400°F to 700°F (204°C to 371°C) and from 750°F to 2000°F (398°C to 1092°C), respectively (Allen and Roberts, 1978). Such temperatures exert a number of stresses on the well which may include compression or expansion causing pull-out or buckling of the casing, cracking of cement, strength retrogression of cement, and corrosion rate increases. In addition, to achieve the most efficient operation, heat loss through the borehole is undesirable.

To withstand the stresses exerted by high temperatures during operation, casing and cementing programs can be selected that provide protection against well failure. Heavier grade casing such as K-55, N-80, or P-105, plus specially threaded buttress connections can withstand compressive and tensile strengths exerted during heating and cooling (Allen and Roberts, 1978). Data on the range of temperature various grades of casing can tolerate are presented in Table 9.3.

Use of good cementing procedures is also important to insure well integrity (Farouq, 1979). In general, cement should be circulated to the surface, with specially designed slurries placed in zones where high temperatures are being generated. The cement slurry may include an inert filler, such as silica flour, to arrest strength retrogression. Where loss of heat through the borehole is undesirable, perlites or vermiculite can be added to provide

TABLE 9.3
ALLOWABLE TEMPERATURE CHANGE AT SHOE
(Farouq, 1979)

Casing Grade	Willhite* (°F)	Willhite* (°C)	Gates* (°F)	Gates* (°C)
H-40	170 - 200	77 - 93	170 - 230	77 - 110
J-55	240 - 275	116 - 135	250 - 310	121 - 154
N-80	350 - 400	177 - 204	370 - 480	188 - 249
S-95	410 - 475	210 - 246	-	-
P-110	-	-	520 - 630	271 - 332

* Various experimenters

a more efficient thermal insulating barrier between the casing and the formation (Halliburton Services, 1981).

Injection wells used for steam and air thermal recovery processes are used for disposing of water produced during operation. These are generally designed as salt-water disposal wells. Schematic diagrams of both a steam injection and a fire flood injection well are shown in Figures 9.6 and 9.7, respectively.

In chemical enhanced-recovery processes, injection wells are used for directing the flood water as well as for disposal of produced water. Surface equipment for this process is designed to blend and to inject the chemically-treated water. In flooding, corrosion of well equipment and casing may be more pronounced from the presence of sodium hydroxide or other alkaline chemicals. A detailed discussion of alkaline corrosion has been provided in Chapter 6.

Caustic-flooding injection wells are designed to minimize corrosion by selecting appropriate construction materials. Particular grades of casing, such as C-75 and epoxy-resin fiberglass reinforced pipe, have exhibited a higher resistance to corrosion than common steel. Coatings or liners of cement or plastic materials can also reduce susceptability to corrosion. Further protection can be attained by using a corrosion-resistant cement such as a non-aqueous epoxy-resin based cement. Epoxy-resin cements are highly resistant to caustic and mineral acids, solvents, and other corrosive materials (Western, Co., 1981).

Miscible-displacement injection wells generally are designed like other standard injection wells. Corrosion, however, can also be a major problem to carbon-dioxide injection wells. Stainless steels and other special metal alloys, plastics, and/or coatings may be required to reduce the rate of corrosion and to increase casing longevity. In addition, the organic solvents used for hydrocarbon displacement injection are corrosive to plastic materials, which prevent their use in organic-solvent injection wells.

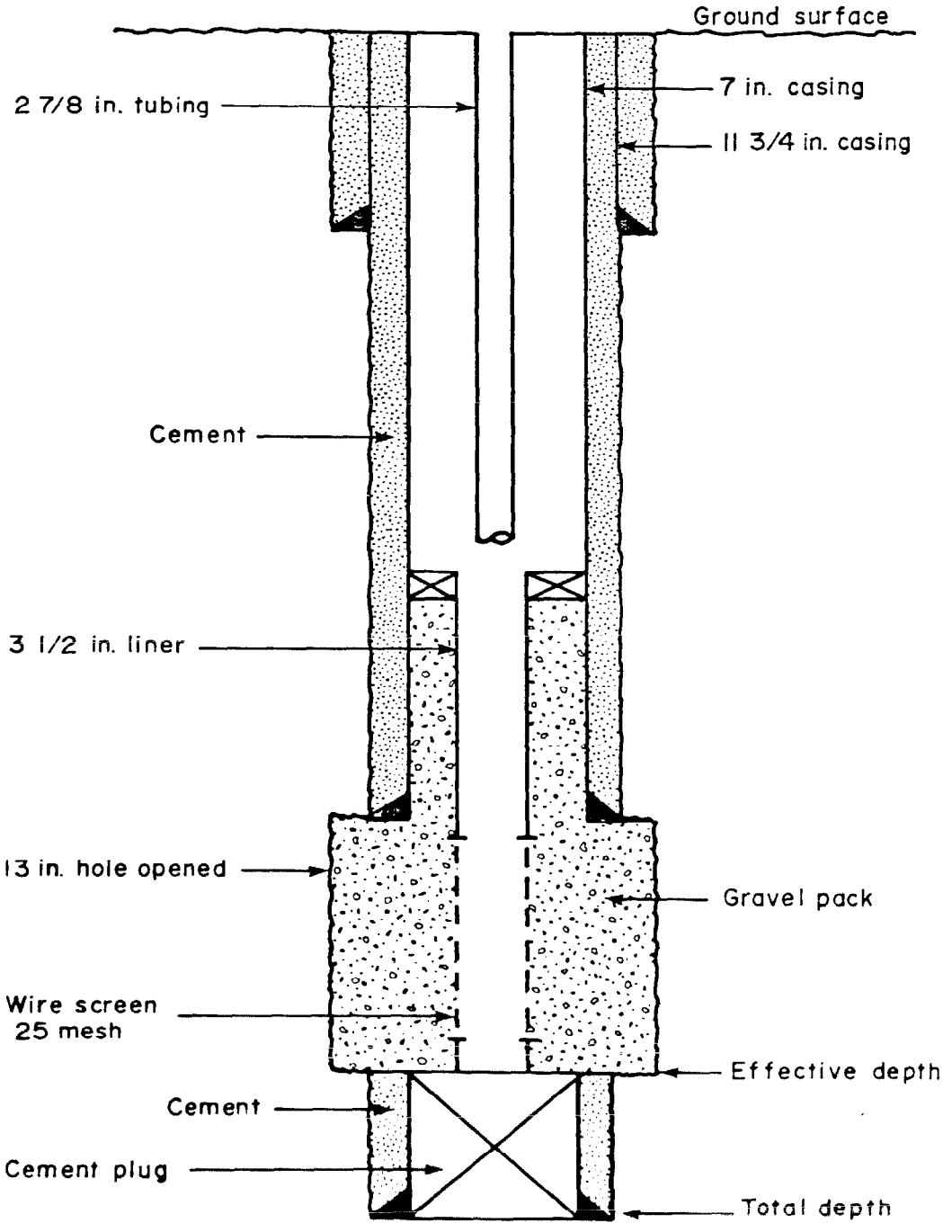

Figure 9.6. Diagram of steam injection well used in the Cat Canyon Field, California

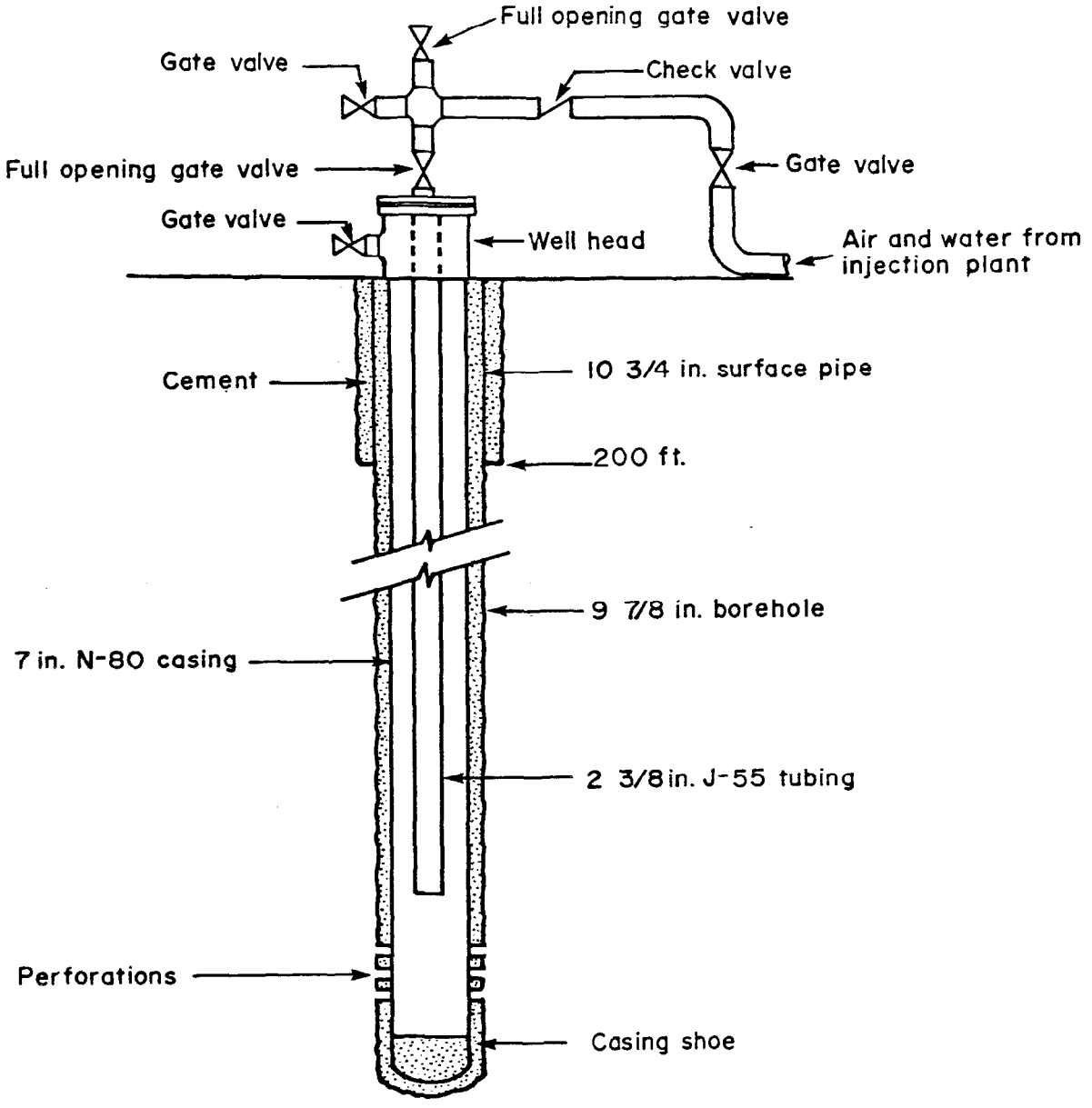

Figure 9.7. Diagram of fire-flood injection well used in the Lynch Canyon, California

9.3 LIQUID HYDROCARBON STORAGE

9.3.1 Description of the Practice

For some time, petroleum products have been stored underground in large caverns in soluble rock formations created by solution processes. Generally, stored petroleum products have included natural gas liquids such as ethane, propane, and butane. The Federal government's Strategic Petroleum Reserve Program targets crude oil for extensive underground storage [up to a billion barrels (1.6×10^8 m^3)] (Medley, 1978).

Storage caverns can be developed in rock formations like shale, limestone or granite, but salt deposits are most commonly used. The caverns may be mined specifically for storage or may exist as a result of commercial brine production. Typically, the caverns are from 100 to 150 feet (30.5 to 45.7 m) in width and extend vertically around the injection well for several hundred feet (several hundred meters) (m). In addition to the use of injection wells for storing hydrocarbons, wells may be used to dispose of the brines produced during cavern formation and to fill the cavern with product. Injection and withdrawal of hydrocarbons and brine can be conducted separately or simultaneously (Gas Processors Association, 1975; Geraghty & Miller, Inc., 1977).

For a hydrocarbon storage operation to work successfully, caverns must be completely sealed and impervious to prevent injection fluid loss. Completing high quality wells through cap rock overlying the salt dome is often a complex undertaking. Protection of the roof of the cavern and the pipe can be provided by floating a light hydrocarbon blanket above the leaching zone.

9.3.2 Well Design

To provide maximum protection against vertical escape of injected hydrocarbons into fresh-water bearing formations, injection wells are usually fully cased and cemented with several different sizes of casing. As shown in Figure 9.8, the casing and cement program of a hydrocarbon

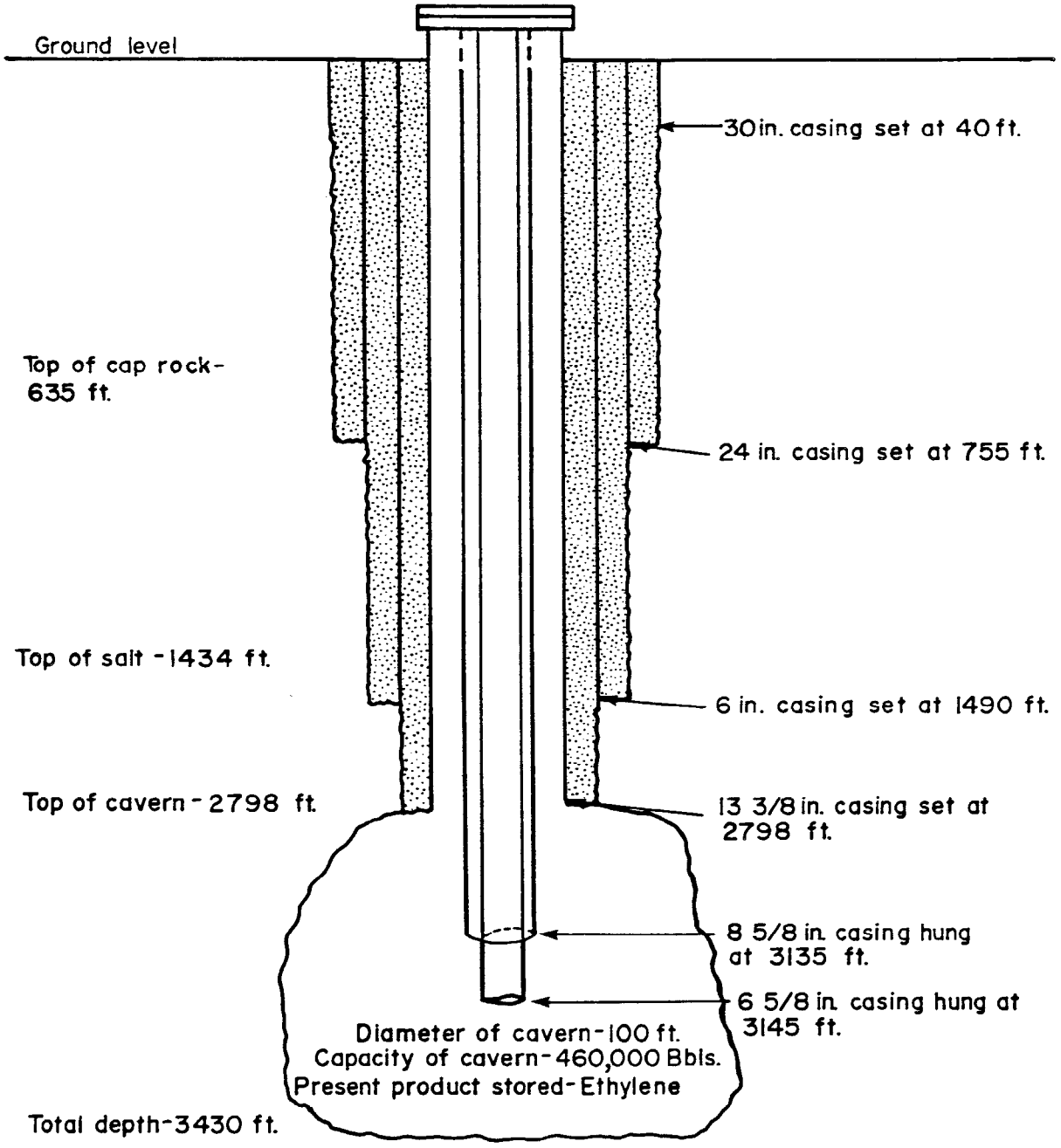

Figure 9.8. Diagram of hydrocarbon-storage injection well

storage well is more extensive than those associated with either salt-water disposal or enhanced oil recovery. The well generally consists of an inner string of casing set within the salt body and cemented to the land surface, surrounded by as many as four or five other strings of casing set above and on top of the cap rock which are also cemented to the surface. Prior to use the casings and the caverns are pressure-tested and periodically thereafter. Injection and withdrawal can be conducted simultaneously through the tubing and annulus to control the brine that is displaced as the hydrocarbons are injected (Geraghty & Miller Inc., 1977).

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10. SELECTED CLASS III AND CLASS V INJECTION WELLS

Class III and Class V Injection wells discussed in this chapter are utilized in the production of energy or the extraction of minerals. Industrial processes, injection practices, and conditions applicable to the use of these wells are widely variable and involve both commercial operations and technologies that are still being researched and developed. Additionally many utilize the injection of non-hazardous materials such as water or oxygen. The technologies described in this section are restricted to Frasch sulfur, solution mining with fresh-water solvents, solution mining with chemical solvents, in-situ combustion of fossil fuels, and geothermal energy development.

10.1 FRASCH SULFUR INJECTION WELLS

10.1.1 Description of the Practice

The Frasch sulfur-mining process is used commercially along the Gulf Coast of Texas and Louisiana, and in western Texas. The process, developed by Herman Frasch at the turn of the century, accounts for about two-thirds of the United States' sulfur production. The Frasch process is used primarily to recover sulfur from deposits in the limestone/gypsum portions of the caprock of salt domes. The sulfur is obtained by injecting hot water to melt it, allowing it to be pumped to the surface.

10.1.2 Well Design

The Frasch process utilizes a single-well system to simultaneously inject hot water and air and to recover the sulfur (Figure 10.1). A borehole is drilled to the top of the caprock overlying the sulfur deposit. Casing is seated in the top of the caprock, and the borehole is extended to the bottom of the sulfur deposit. Casing is installed in the borehole and the lower end is perforated with small diameter holes in two separate zones. A packer is used to seal the casing between the two zones of perforation. A smaller diameter pipe is placed through the

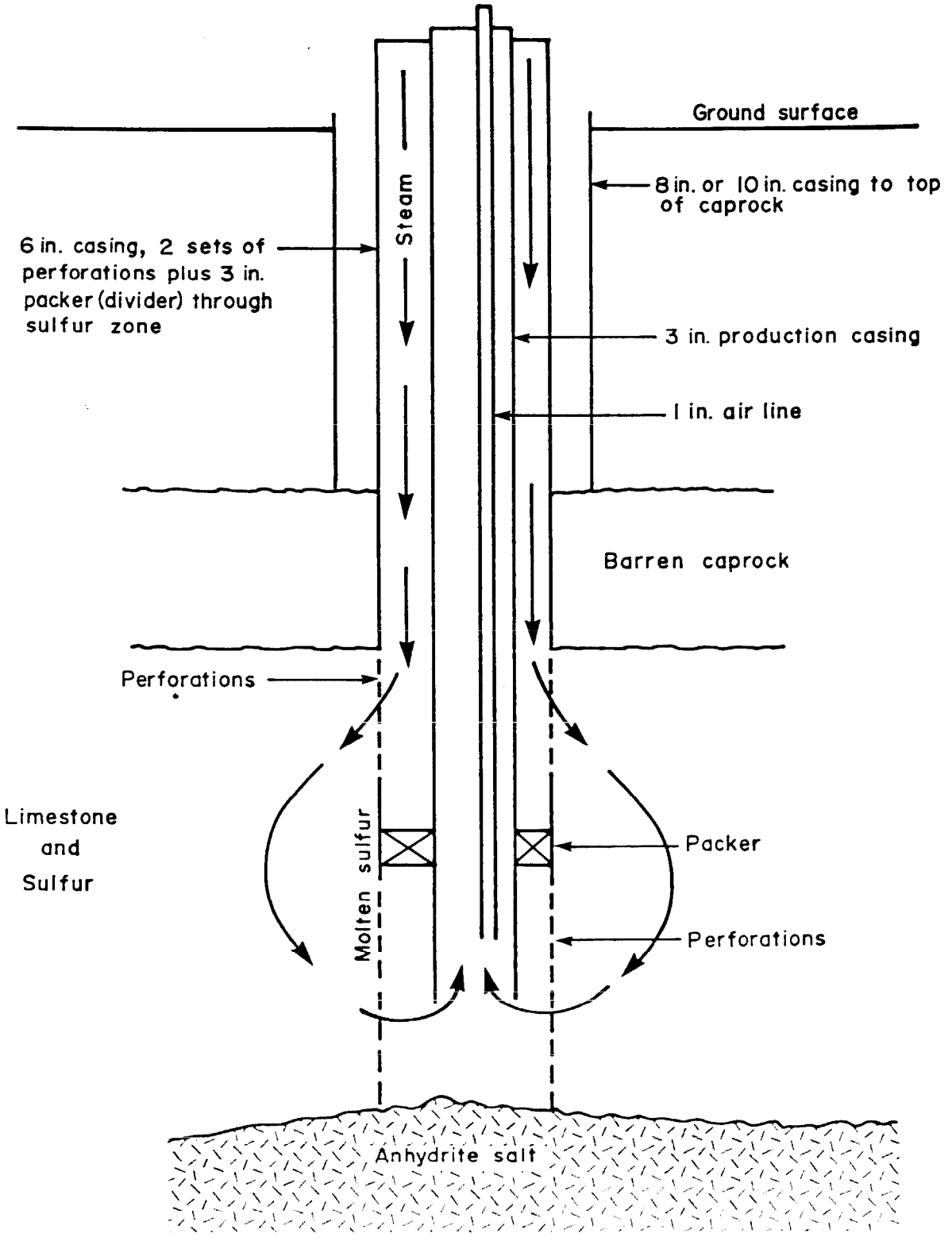

Figure 10.1. Schematic diagram of a Frasch sulfur well

packer to channel the melted sulfur to the surface inside of which is another pipe for the injection of compressed air.

The mining process is initiated by pumping super-heated water [325°F (163°C)] down the well assembly where it flows out both perforated zones into the sulfur-bearing deposit (Figure 10.1). When the temperature of the sulfur reaches or exceeds 246°F (119°C), the liquid sulfur flows by gravity into the bottom of the well. Pumping water down the inner casing is discontinued at this point, and the liquid sulfur is forced into and partially up the inner casing by the pressure from the hot water. Compressed air is injected then to aerate the sulfur so that it will rise to the surface.

Construction characteristics of Frasch production wells differ with operators, individual projects, and geological conditions. For example, the surface casing and the outer injection casing are in some instances fully cemented and in others cemented only at the shoe. In general, casings are cemented only as needed, mainly where there are high formation pressures or pressure losses within the production zone (Geraghty & Miller, 1980).

As the sulfur matrix is mined, the caprock may weaken enough to collapse under the weight of the overburden, which in turn may collapse. Depending on the depth and degree of compaction, the settlement may be propagated to the land surface as subsidence and cause sheared casings and ultimate loss of the well. Operators generally separate their wells into groups to limit their exposure to a sudden formation movement (Donner and Wornat, 1973; Shearon and Pollard, 1950).

The injection of super-heated water results in significant casing expansion and contraction. The well-casing program, therefore, must be compatible with such high-temperature operation. The tubing and packer installation also must be compatible with any temperature cycles likely to occur to prevent tubing elongation or contraction which could unseat the packers.

Although liquid sulfur is not corrosive to well equipment, the combination of water and air injected in the lift process is highly corrosive to steel. In addition, the formation water produced with the sulfur can be corrosive to steel, especially at elevated temperatures. Cement-lined

pipe or special alloys are used in some operations to avoid premature loss of wells (Donner and Wornat, 1973).

10.2 FRESH-WATER SOLUTION-MINING WELLS

10.2.1 Description of the Practice

Solution mining by injection of fresh-water solvents is used in producing minerals such as sodium chloride, potassium chloride (potash, sylvite), sodium carbonate (trona), and phosphate. The techniques may be extended to other water-soluble minerals in future applications.

Sodium chloride (salt) is mined using a single-well or a multiple-well system and is practiced from depths ranging from several hundred feet (100 m) to about 10,000 feet (312.5 m) in both domed and bedded salt deposits.

Potash is produced using either single-well or multiple-well solution-mining systems and has been tested in New Mexico, Europe, and Canada (Davis and Shock, 1970; Husband, 1973). Potash is selectively extracted from beds associated with other soluble materials such as sodium chloride. The potash is mined by injecting a sodium-chloride brine that selectively dissolves potash and leaves sodium salts behind. Mining efficiency can be increased by heating the brine to increase potash solubility.

Phosphate deposits are less suitable to classical solution-mining techniques than are sodium and potassium salts. In fact, the in-situ production of phosphate minerals involves the physical break-up of the mineral deposits by a water jet and pumping the slurry to the surface. This experimental technique, known as borehole slurry mining, is being tested in the phosphate deposits of Florida under a research program by the Bureau of Mines (Anonymous 1980).

Phosphate resources occur throughout the coastal plain regions of the southeastern United States. Two regions in particular have been identified by the Bureau of Mines as potential areas for in-situ development. These include the deposits of central Florida and those of eastern North Carolina (Kasper, et al., 1979).

10.2.2 Well Design

Single-well solution-mining techniques utilize the same borehole for both injection and production. Because the areal extent of the solution process is quite limited, this method is best suited for very thick-bedded formations or dome-like deposits (Davis and Shock, 1970; Geraghty & Miller, Inc., 1980). Multiple-well solution-mining systems utilize one or more wells for production and a separate set of wells for injection of the fresh-water solvent.

Single-Well Systems

There are four basic single-well systems for solution mining, top annular-injection, bottom injection, trump, and bottom annular-injection (Figure 10.2). Which system is utilized depends on geology and mining strategy. The top annular-injection method is the type commonly used for salt-solution mining (Jacoby, 1973).

Well construction for all methods is similar. A conductor or surface casing is installed through the unconsolidated overburden into bedrock using either the cable-tool or the rotary-drilling method. After the casing is in place, it is cemented to the surface and allowed to set. Drilling is then continued into the top of the salt formation where an intermediate casing string is set and cemented back to the surface. Drilling is continued to the bottom of the salt deposit or to a specific design depth. The borehole is then equipped with one or more free-hanging strings of tubing extending from the surface to a point near the bottom of the borehole (Jacoby, 1973). Typical casing sizes are presented for a bottom-hole injection system in Figure 10.3.

After completion, water or brine is injected through the annulus or down the central tubing. The product is then recovered up an annulus or up the central tubing.

Single-well mining of salt deposits presents various unique considerations including control of cavern geometry, corrosion, and cement incompabilities. Without proper control of solution-cavern geometry the structure

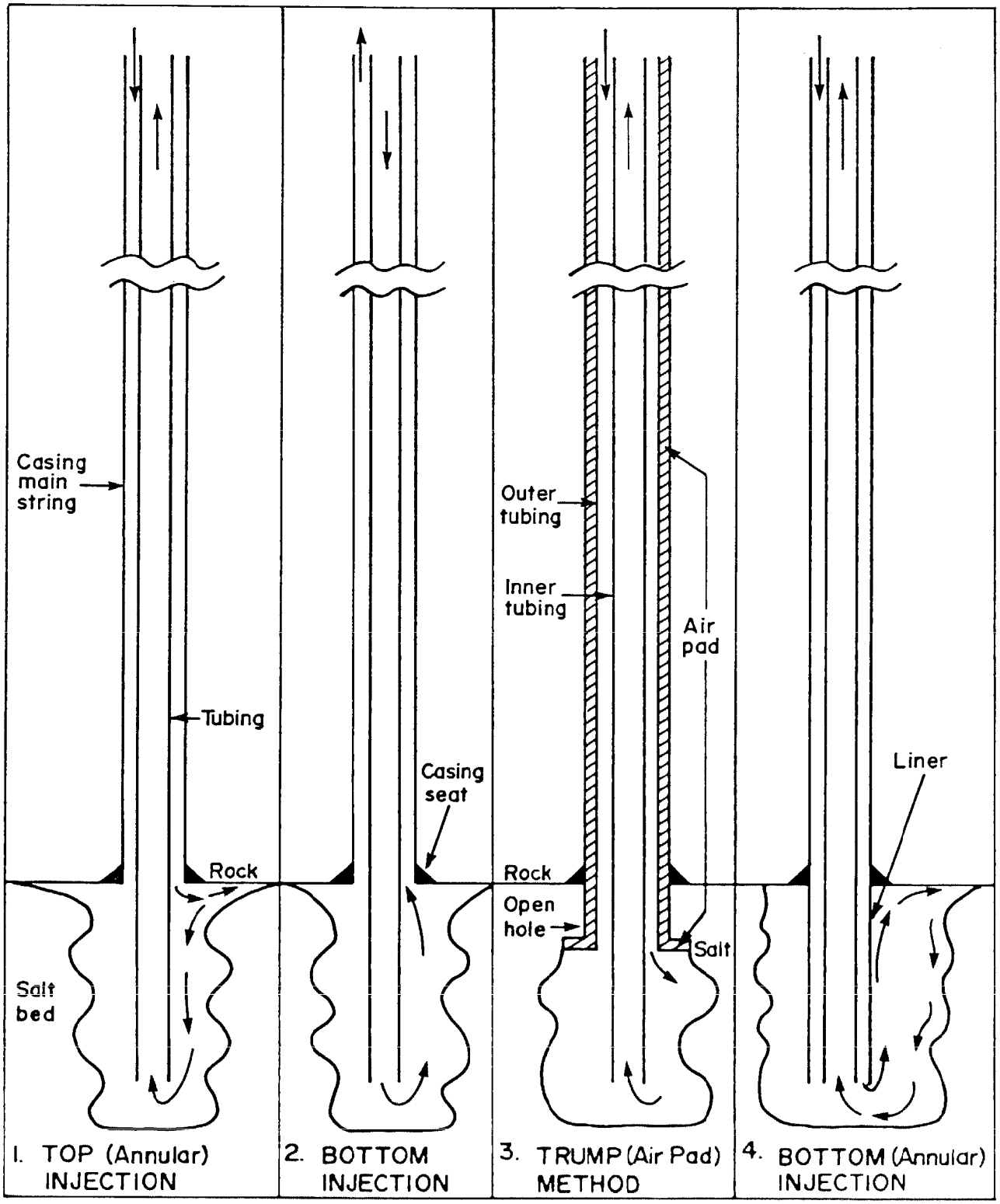

Figure 10.2. Basic single-well systems for solution mining (Jacoby, 1973)

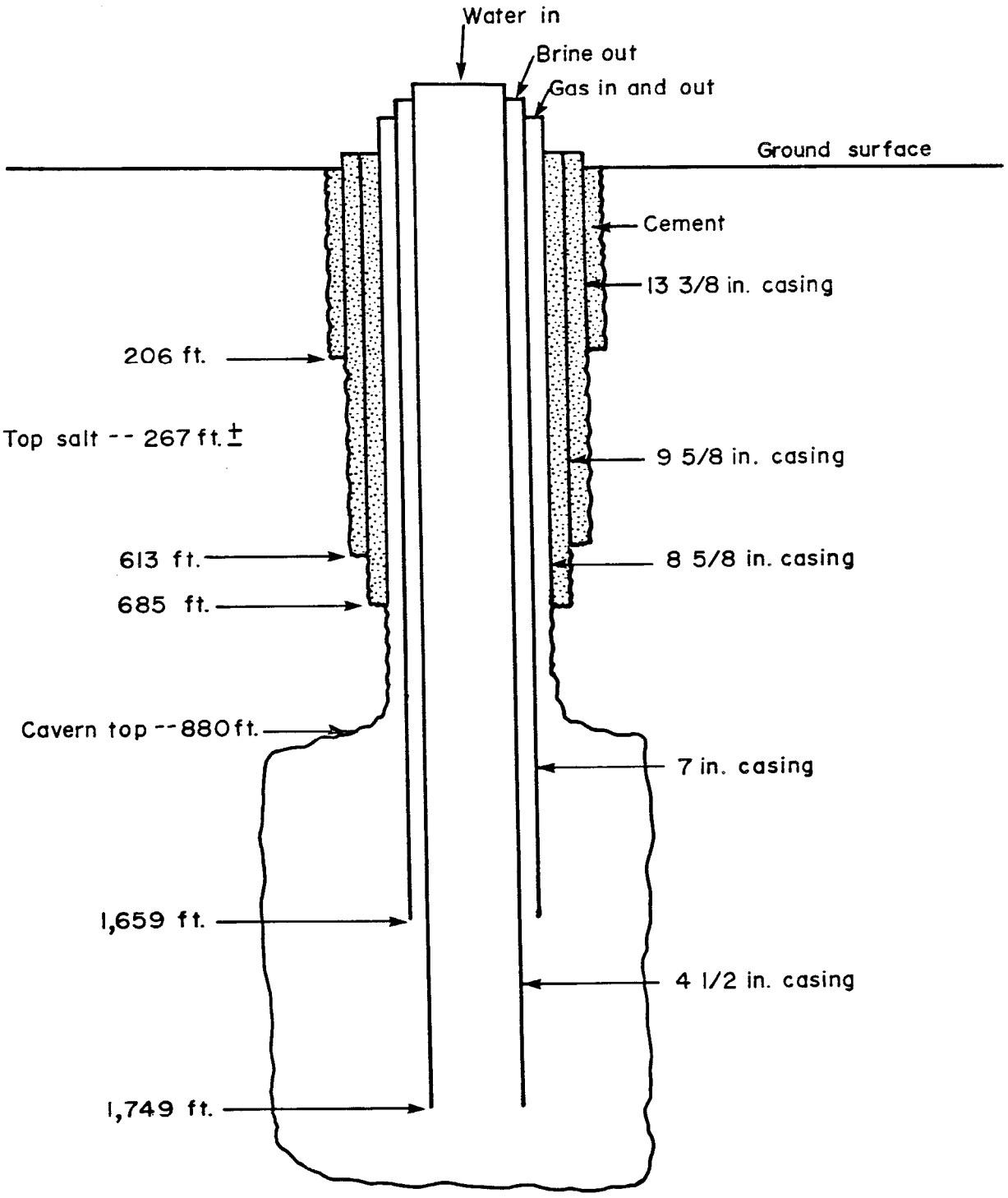

Figure 10.3. Typical salt solution-mining well (United Salt Corporation, 1976)

can collapse, damaging the casing and possibly propagating subsidence to the surface.

Logging operations are useful in determining cavern orientation (Hicks, 1974; Caldwell and Strobala, 1966). The existence of any insoluble zones can be detected which could collapse and cause casing damage. Logging techniques can help define the geometry of the cavern roof, an aid to avoid roof collapse and shearing the casing.

The injection of high salinity brines makes the control of electrochemical corrosion in solution-mining wells important. Cathodic protection methods have been suggested for use (Titterington, 1963). (See Chapter 6 for more information.)

Drilling and cementing operations in salt mining require special fluids or additives to avoid formation incompatibility (Davis and Shock, 1970; Baker and Smith, 1974; Laswell, 1976). The use of water-based drilling fluids with low ionic content can lead to expansion of associated clay and to dissolution of salt materials.

Cement additives are necessary to attain proper cement bond with sufficient strength qualities. Sodium chloride is a commonly used additive when slurries are expected to contact fresh-water sensitive shale, and clay, as well as salt formations. The addition of salt can also improve early strength development and allow turbulent flow patterns at lower velocities that are important in setting a homogeneous cement sheath. In addition to sodium chloride, other cement additives and circulation practices are developed specifically for salt applications. Oil-well service companies have extensive experience in this area and are best qualified to prescribe the proper grouting program for each specific case.

Multiple-Well Systems

The multiple-well method is commonly used in solution mining of thin-bedded deposits of sodium chloride and potash. One or more pairs of injection and recovery wells interconnected by hydraulic fracturing techniques are commonly used (Shock, 1966; Henderson, 1974; Manker 1966; Davis and Shock, 1970).

Injection wells are generally constructed with one or more strings of cemented casing. Wells used for fracturing or for high-pressure fluid injection have traditionally been completed with a tubing and packer or with a tubingless arrangement. Operations using fluid to fracture the formation require a casing with sufficiently high burst strength to withstand the pressures. Fracturing may be accomplished in open hole or through a perforated interval in the casing. In either case, the casing string is exposed to the pressure and corrosiveness of the brine.

In operations where tubing and packer are used, the fracture is initiated in an open hole. By using the tubing and packer method, a thin-walled casing can be installed since it is not subjected to initial injection pressure. Also, the cement behind the casing is not exposed to fracture pressures which presents less opportunity of migration in a poor cement job.

Experience has shown that failures of hydraulic fracturing operations can occur as a result of inadequate cementing practices, structural weakness of the media leading toward fractures propagating in wrong directions (i.e. outside the salt zone), existence of downward vertical fractures allowing fluid to escape into heavily fractured or permeable formations, and improper placement of the fracturing well in relationships to the production well (Henderson, 1963). Special siting, logging, and well-construction procedures are employed to avoid these problems. A protective blanket of oil can be floated over the leached zone to limit the vertical migration of the solute. Washouts can occur if this protective blanket rises past the cemented string in wells completed without tubing and packer.

Slurry Mining

Slurry or borehole mining refers to the process in which a deposit of insoluble but relatively soft mineral is reached by a borehole and is broken down by the injection of a high-velocity stream of water. The resultant slurry of ore and water is pumped to the surface for processing as shown in Figure 10.4. Borehole mining is an experimental technique which has been tested on coal, uranium (Savanick, 1979), and phosphate deposits.

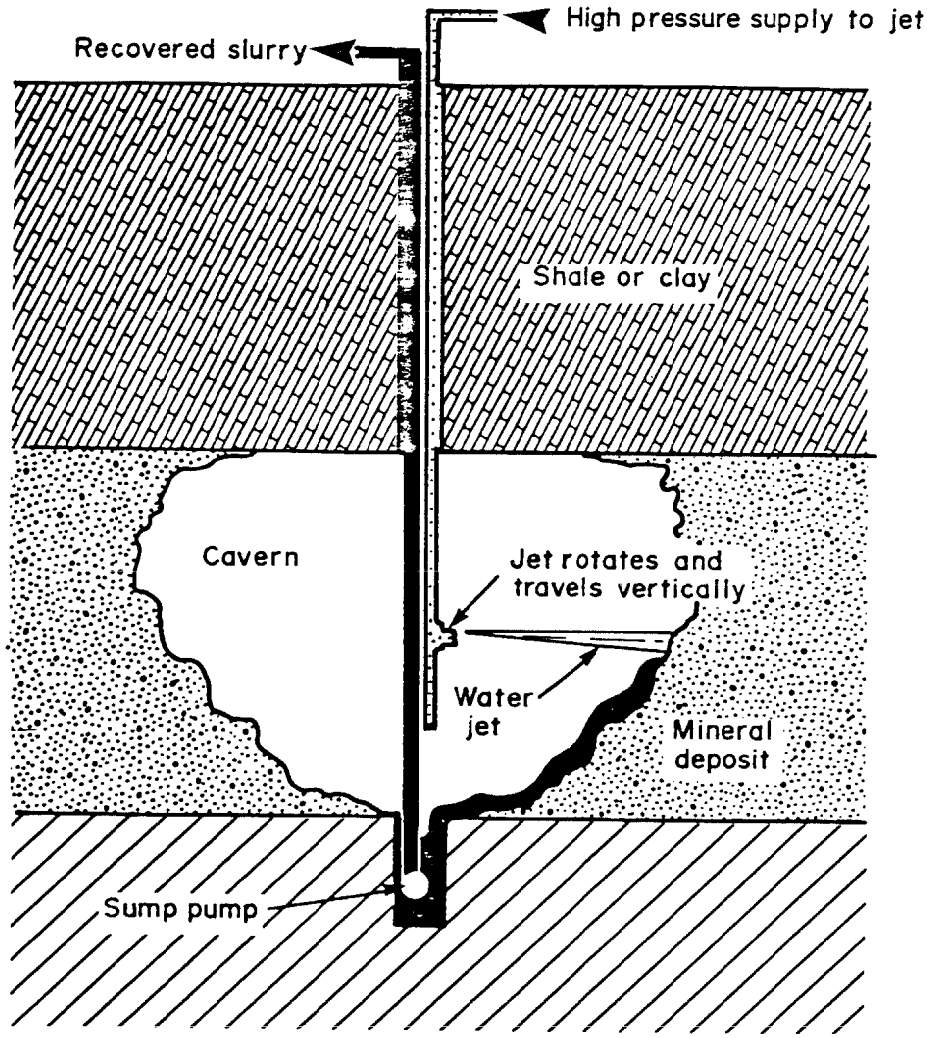

Figure 10.4. Schematic diagram of the hydraulic borehole slurry mining (Kasper, et al., 1979)

A hole of sufficient diameter to accomodate the hydraulic jetting tool gives access to the ore. Typically, an 18 to 24-inch (44 to 59 cm) diameter hole is drilled to approximately six feet (1.8 m) below the mineral-bearing strata. A casing is installed above the ore body to prevent caving of the overburden. The section of the hole within the ore body is not cased. The cutting-jet assembly is positioned in the hole at the end of a rigid service column containing the necessary conduits for pressurized water and for transport of the slurry to the surface. The lower section of the cutting jet assembly contains the slurry pump which is installed in the hole below the ore body. After the mining unit is positioned in the borehole and the above-ground equipment is installed, the high-pressure water, slurry, and hydraulic connections are made.

Normally, the underground mining operation is begun with the jet set at the lowest position. The jet rotates and cuts material through an arc of 200 to 300 degrees leaving a segment of unmined material to support the overlying strata. The material is removed to a radius of up to 76 feet (23 m), depending on the properties of the ore and the pressure, nozzle, shape, and diameter of the jet system. After the material is removed, the jet is raised to reach the next level of ore. The slurry is pumped to the surface where it is decanted for processing. The decanted water is recycled and used for slurrying new ore. Treatment requirements for this water are minimal since low concentrations of suspended solids do not interfere with the jetting operation.

The duration of mining in a borehole is a function of the ore characteristics and the capacity of the jetting apparatus. Kasper, et al. (1979) projected that a borehole 46 to 77 feet (14 to 23 m) in diameter could be completely mined in 8 to 24 hours, assuming an ore zone 30 feet (9 m) thick.

10.3 CHEMICAL-SOLVENT SOLUTION-MINING WELLS

10.3.1. Description of the Practice

Uranium and copper are the two principal metals mined by the use of chemical solutions injected through

wells. Uranium is being extracted on a commercial scale in several states; however, copper leaching has been largely experimental except for a few small commercial systems which are not in operation at present because of market conditions and depletion of the ore deposits. Other metals that may eventually prove suitable for mining by in-situ leaching are gold, silver, aluminum, and nickel/cobalt.

Uranium

In-situ solution mining is a practical and economic method of extracting uranium from low grade ores. The process involves the injection of an acidic- or an alkaline-leach solution (lixiviant) into the uranium-bearing formation. A complex salt solution, formed by the lixiviant and the dissolved uranium, transports the uranium from the host rock. Production wells remove the uranium-bearing solution from the subsurface for recovery of the uranium at a surface facility. Benefits of in-situ mining include a smaller capital cost for deep or small scattered deposits, low labor costs, improved worker safety, short preparation time, and fewer environmental impacts (e.g., disturbance of the land surface or disruption of surface runoff) (Larson, 1978; Huff, et al., 1980). However, careful monitoring is essential to prevent the toxic lixiviants from polluting potable water-bearing zones.

Leachable uranium deposits are found in sandstone formations associated with mountain-front, near-shore marine, and deltaic environments, as well as intermontane basins (Galloway, et al., 1979). Uranium mineralization occurs as elongated, narrow lenses often less than a few hundred yards (few hundred meters) in length (Thompson, et al., 1978). The uranium ore is found in "roll-type" deposits along the margins of a reducing ground-water environment. The dominant uranium minerals associated with the roll-type deposits are uraninite and coffinite, a uranium silicate. The ore bodies are generally found at depths ranging from tens of feet (a few meters) to several thousand feet (hundreds of meters) below land surface.

Copper

In-situ copper leaching techniques are different in many aspects from the methods used in solution mining of uranium, primarily a result of the competency of the rocks in which copper occurs. The copper-bearing rocks of low permeability generally require fracturing by explosives before effective leaching operations can be started.

More than 80 percent of the copper production of the world comes from porphyry copper deposits (Kasper, et al., 1979) which occur as hydrothermal veins and replacement deposits in the western United States. Porphyry copper deposits are found along the mountainous Cordilleran Belt from Alaska to Central America. These deposits are also an important source of associated metals such as molybdenum, gold, and silver.

The techniques chosen for recovering copper depend largely on the type of geologic setting of the ore body. Depths of wells may range from tens of feet (a few meters) to thousands of feet (hundreds of meters). In many places lixiviants are applied to dumps by sprinkler systems rather than by injection wells, and other wells are used to recover the pregnant solutions.

Three general types of in-situ copper leaching mining environments are described by Wadsworth (1977). Type I deposits occur above the water table with ore bodies having one or more sides exposed. This type of deposit is leached by pumping solvent into boreholes, by surface spraying, or by surface flooding. The pregnant solution is extracted by a pump in a product well.

Type II deposits are located below the water table but are generally less than 1,000 feet (305 m) deep. These deposits may require extensive fracturing, and the copper rubble may be leached by injection of lixiviants such as iron solutions, oxygen, and sulfuric acid. The copper-enriched solutions are recovered through wells. A major difficulty with Type II deposits is predicting flow patterns after fracturing for complete removal of the copper solutions and prevention of excursions of toxic leachate into underground-sources of drinking water.

Type III deposits occur below the water table but are too deep for conventional mining operations. Following fracturing by conventional explosives, hydrofracturing, or chemical dissolution, lixiviants are injected under high pressure into the rubble and the pregnant solutions are extracted by recovery wells.

10.3.2 Well Design

Well drilling for in-situ uranium leaching is generally performed by rotary drilling methods, except in areas of competent rock where percussion drilling may be employed. Bentonite muds, guar gum, polyanionic cellulose polymers, air, and foam drilling fluids have been used in drilling in-situ wells (Tweeton and Connor, 1978; Larson, 1978). Upon completion of the drilling, natural gamma, resistivity, and caliper logs can be run to determine a suitable depth for installation of a screen or open hole for injection.

Casing selection is based upon the depth of the well, casing strength, and corrosion resistance. At shallow depths, PVC casing is generally used, although fiberglass-reinforced pipe, carbon steel, or stainless steel can be used because of their greater strength (Huff, et al., 1980; Larson, 1978; Tweeton and Connor, 1978). Corrosion-resistant tubing and packers are used with carbon steel casing or where carbon steel is used in combination with fiberglass or stainless steel casing, to prevent casing deterioration from the leaching solution. Casing diameters of uranium leaching wells generally range from 2 to 7 inches (5.1 to 17.8 cm).

Typically, Type A or B Portland cement is used for cementing in-situ wells, but if an acid solution with a pH of less than 2 is to be used as the lixiviant, epoxy cement can be used (Huff, 1980). The well is checked for leaks and the cement is allowed to harden, after which the cement plug at the base of the casing is drilled out. Depending on the type of bottom-hole completion, the borehole below the casing may be underreamed and cleaned, a liner may be installed, or a screen may be placed below the cement.

Well design takes into account the diameter of the pumps installed and the screen openings needed to prevent

sand invasion of the borehole. Injection well designs also consider the corrosiveness of leaching solutions on the well screens. Virtually every type of well completion has been used with uranium leaching operations. Figure 10.5 illustrates the various techniques used.

Pilot-test operations are generally conducted before production-scale leaching operations begin. The pilot leaching operations are commonly run for a four to five month period to determine recovery and operating parameters (e.g. injection rate and pressure). Various injection/recovery well configurations are used to achieve the best hydraulic and economic returns.

Depending on ore body shape and size, the patterns of wells may be a five-spot (four injection wells surrounding a recovery, or production well), seven-spot, or thirteen-spot configuration (Figure 10.6). Irregular patterns of wells may be needed in places for localized variations in the shape of the ore body. The leach pattern is selected to maximize recovery but does not affect aquifer quality if all injected fluid is recovered.

Copper

There are no representative designs of wells that are used for copper-leaching operations. Some wells consist of 150 to 200 foot (45.7 to 61 m) holes cased with 2 inch (5.1 cm) PVC pipe. Others may be several thousand feet (hundreds of meters) deep with stainless steel casing (Aplan, et al., 1974), and others may not be cased. The copper is leached with either sulfuric acid or ammonia solutions. Advantages of each lixiviant solution are described in the literature (Kasper, et al., 1979; Aplan, et al., 1974; Schuffman and Rowden, 1973).

Figure 10.7 shows assemblies of injection and recovery wells for mining copper. Figure 10.7A shows mining of native copper. Following the fracturing of the ore body, a production well is drilled to the base of the fractured zone for collection of the copper-bearing solution. Figures 10.7B and 10.7C present potential configurations of wells for leaching copper in an abandoned mine or in fractured rocks.

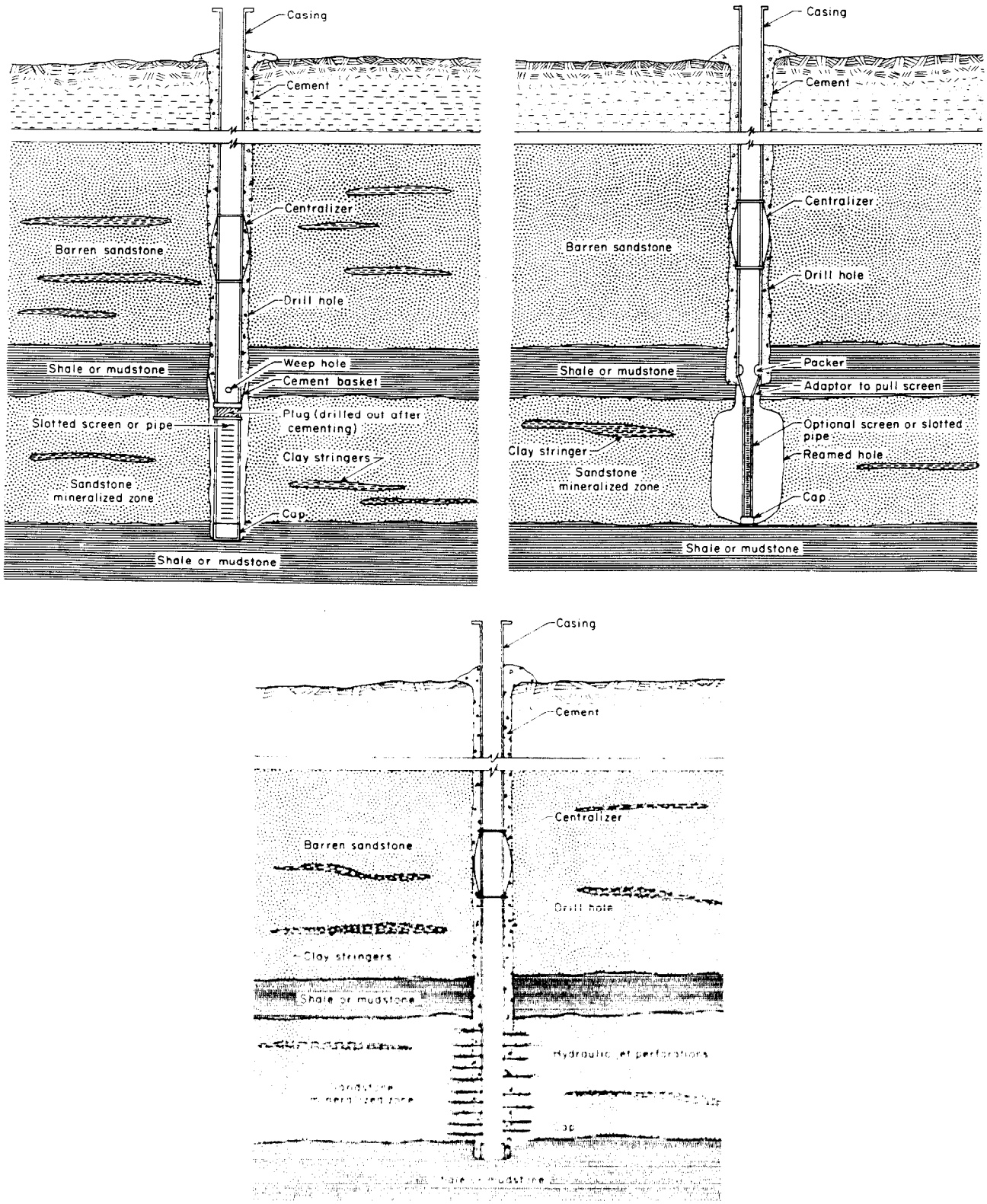

Figure 10.5. Examples of in-situ uranium leaching wells (Larsen, 1978)

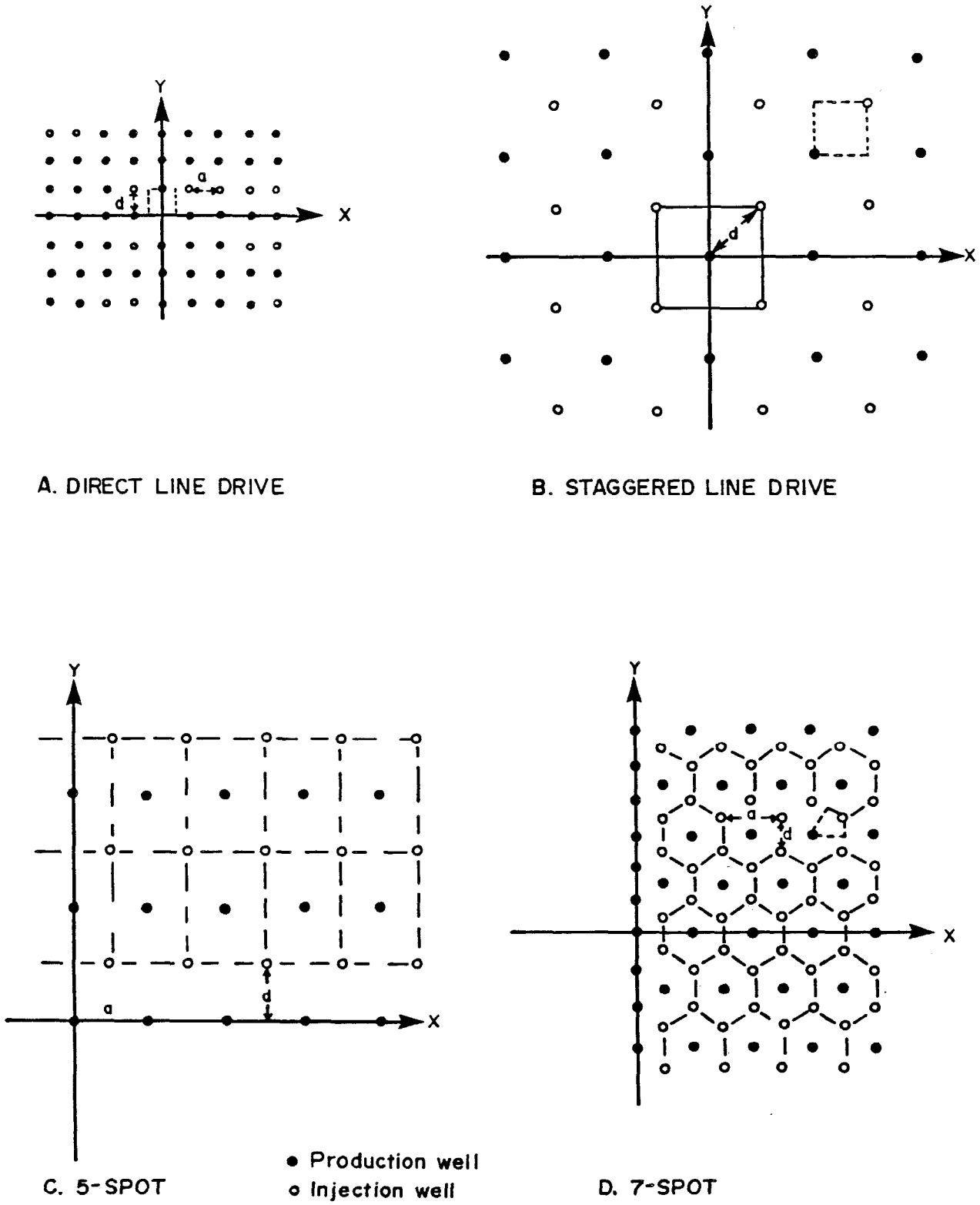

Figure 10.6. Well patterns for in-situ leach mining of uranium (Thompson, et al., 1978)

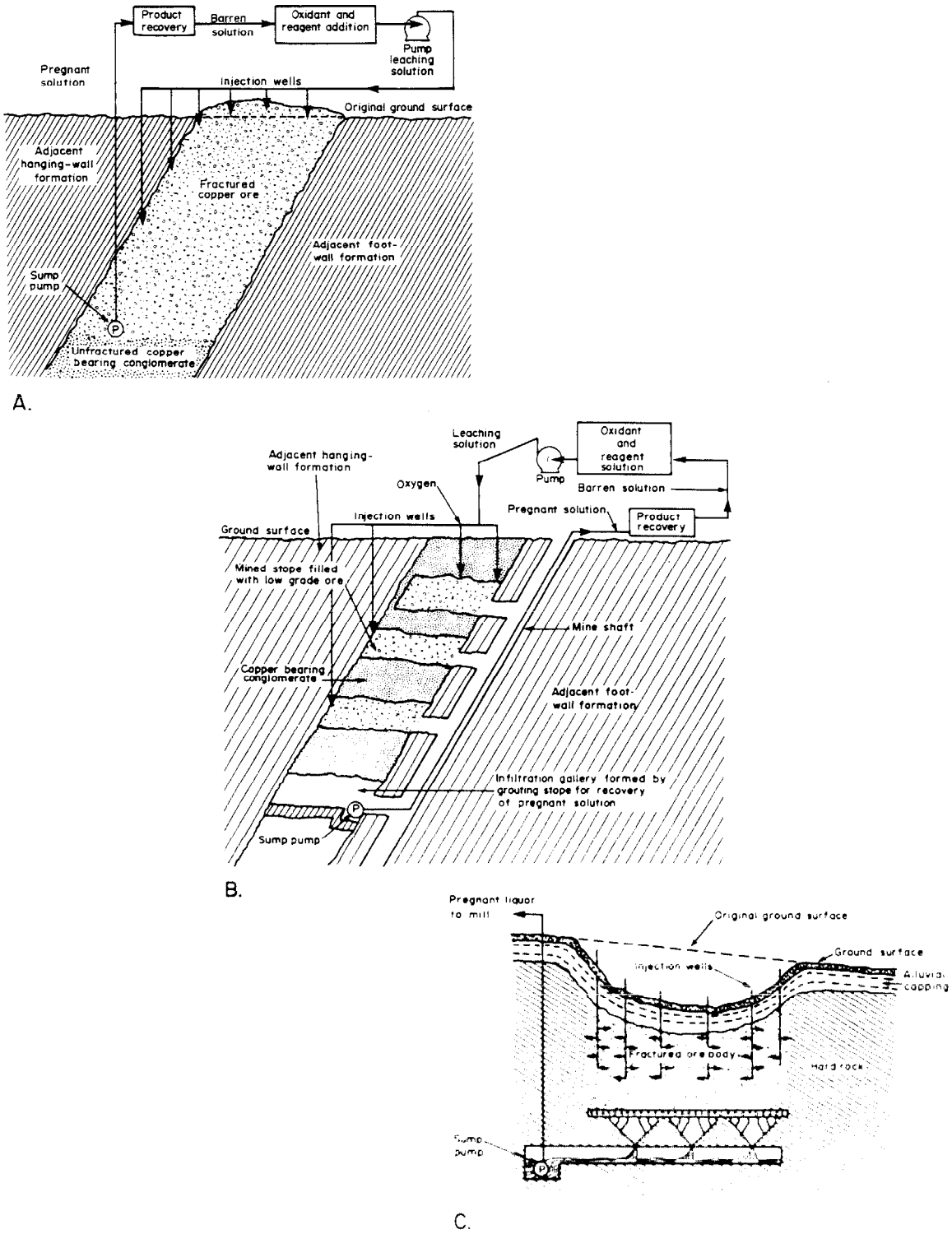

Figure 10.7. Well programs for in-situ leach mining of copper (Kasper, 1979)

10.4 IN-SITU COMBUSTION OF FOSSIL FUELS

Three principal fossil-energy resources, oil shale, coal, and tar sand, are under experimental consideration for in-situ combustion. The physical and geological characteristics of these resources and their unique development requirements present specific demands on injection-well design and construction.

10.4.1 Description of the Practice

Oil Shale

Research and development activities in the field of in-situ combustion of oil shale have focused on two principal techniques, in-situ retorting and modified in-situ retorting. A generalized in-situ retorting process is illustrated in Figure 10.8. The process consists of several steps (DOE, 1977; U. S. Office of Technology Assessment, 1980; Baughman, 1976; Burwell, et al., 1973; Lekas, 1979). The first step is to drill down and fracture the retort zone to form rubble. The retort is ignited, producing hydrocarbons which are then recovered and separated from undesirable byproducts.

Modified in-situ retorting of oil shale generally involves mining a small part of the zone to be retorted and then fracturing the remaining shale to create a highly permeable zone (DOE, 1977; Baughman, 1976; U. S. Office of Technology Assessment, 1980; Occidental Petroleum, 1979; Ashland Oil, 1976). Retorting the column is then initiated by igniting the shale and combustion is sustained by injecting air and gas into the zone. A conceptual drawing of the modified in-situ retorting process is shown in Figure 10.9.

In-situ combustion of coal consists of two principal steps, a preparation process (in which permeability is induced) and actual gasification. Permeable pathways or links in the coal seam between the injection and the production wells can be created by reverse combustion, hydrofracturing, directional drilling, or other techniques.

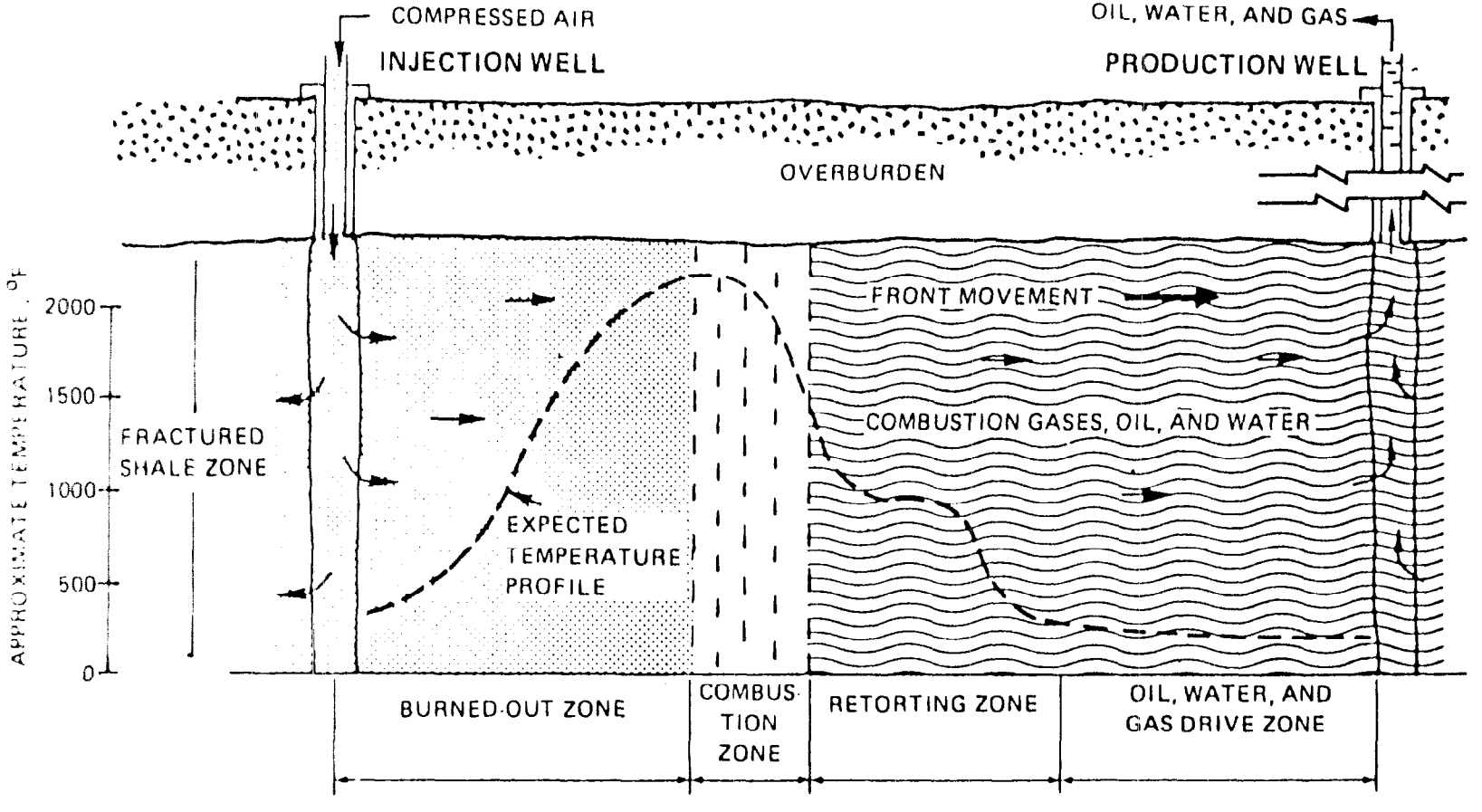

Figure 10.8. Schematic diagram of in-situ retorting of oil shale (Jee, et al., 1977)

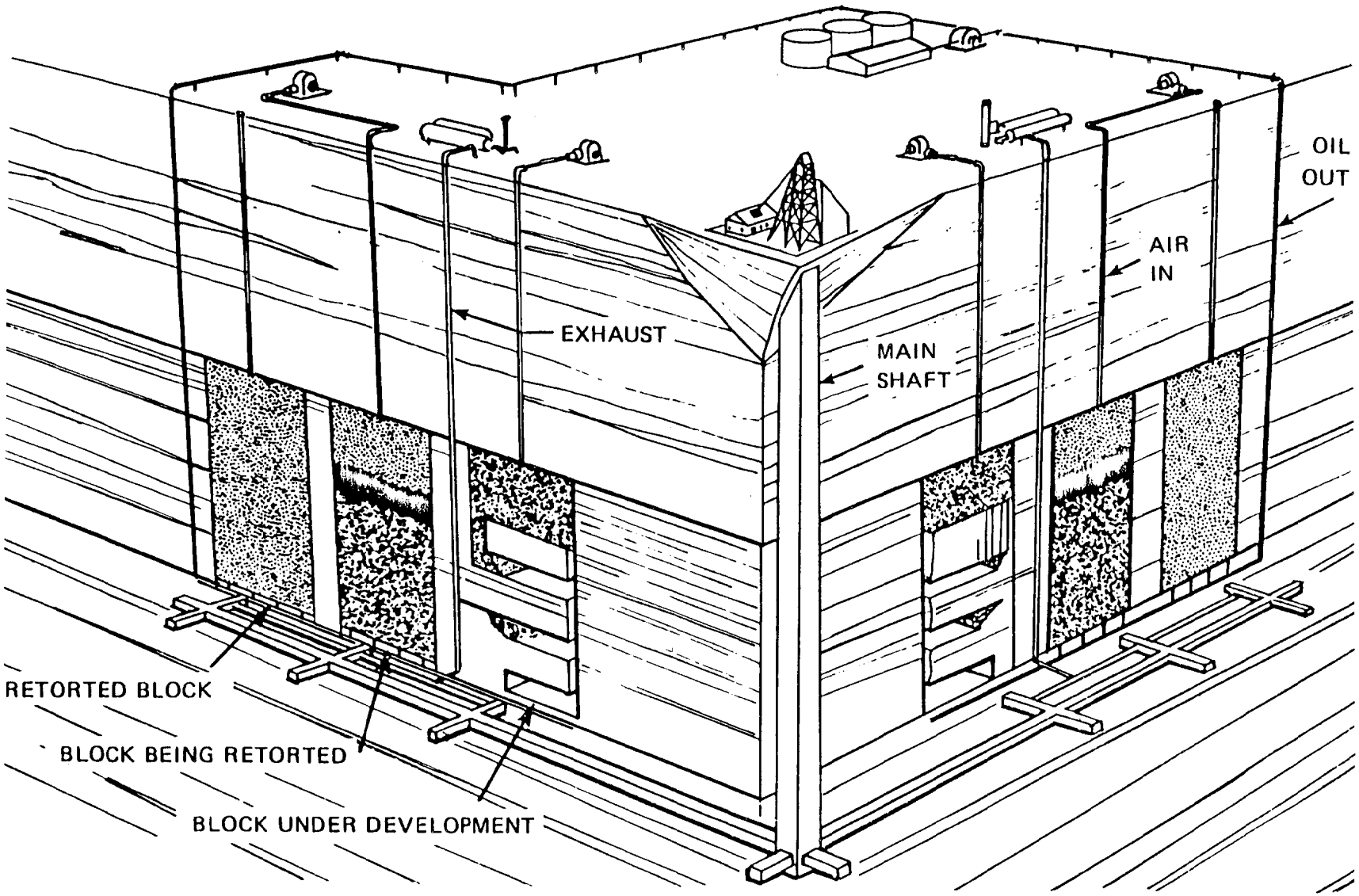

Figure 10.9. Schematic diagram of the modified in-situ retoring process for oil shale (DOE, 1977)

The general concept which is illustrated in Figure 10.10 is referred to as the linked-vertical well method.

The steeply-dipping bed concept (Figure 10.11) is designed to gasify beds of coal that have a steep angle of dip from the land surface. Obvious advantages of this method are the placement of injection wells below the seam where they are unaffected by subsidence, and drilling the output boreholes down the easily-penetrated coal seam. Increased production is achieved from a number of modules operating side-by-side that are linked by drilling or by combustion along the bottom of the gasification zone (Wieber and Sikri, 1977).

The packed-bed process uses fracturing techniques for increasing permeability in coal seams. Explosives are used in this process so that flow can occur through a uniformly packed bed. This results in the exposure of the coal to the gases over a large surface area for long contact periods. The packed-bed process uses steam/oxygen injection at the top of the fractured bed with flow down the bed and toward the lower periphery as shown in Figure 10.12 (Wieber and Sikri, 1977).

In-situ combustion of coal involves two principal types of injection wells, combustion-zone injection and produced-water disposal. The injection wells entering the combustion zones are widely variable in design. They are used for various purposes, including initial combustion zone preparation activities (e.g., hydrofracturing) and air and steam injection during processing. Produced water-disposal wells are necessary to return waters from artificial drawdown operations, which are usually required in the combustion process.

10.4.2 Well Design

Oil Shale

In the modified in-situ process for recovery of oil from shale, access wells are drilled into the top of the mined retort. These wells may be several hundred feet to over one thousand feet (hundreds of meters) deep. In initial experiments both cased and open-hole wells have

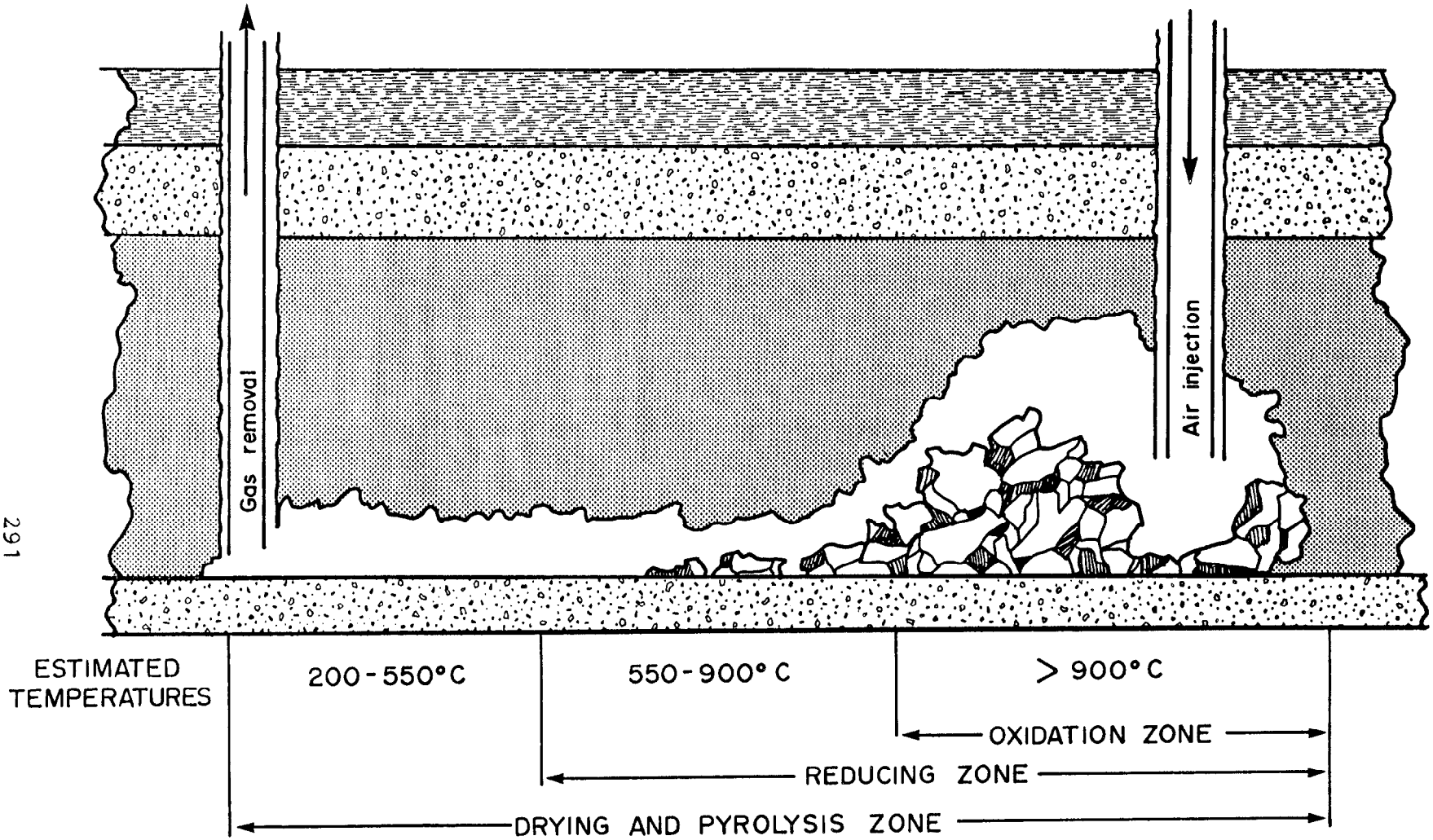

Figure 10.10. Conceptual diagram of in-situ combustion of coal (DOE, 1980)

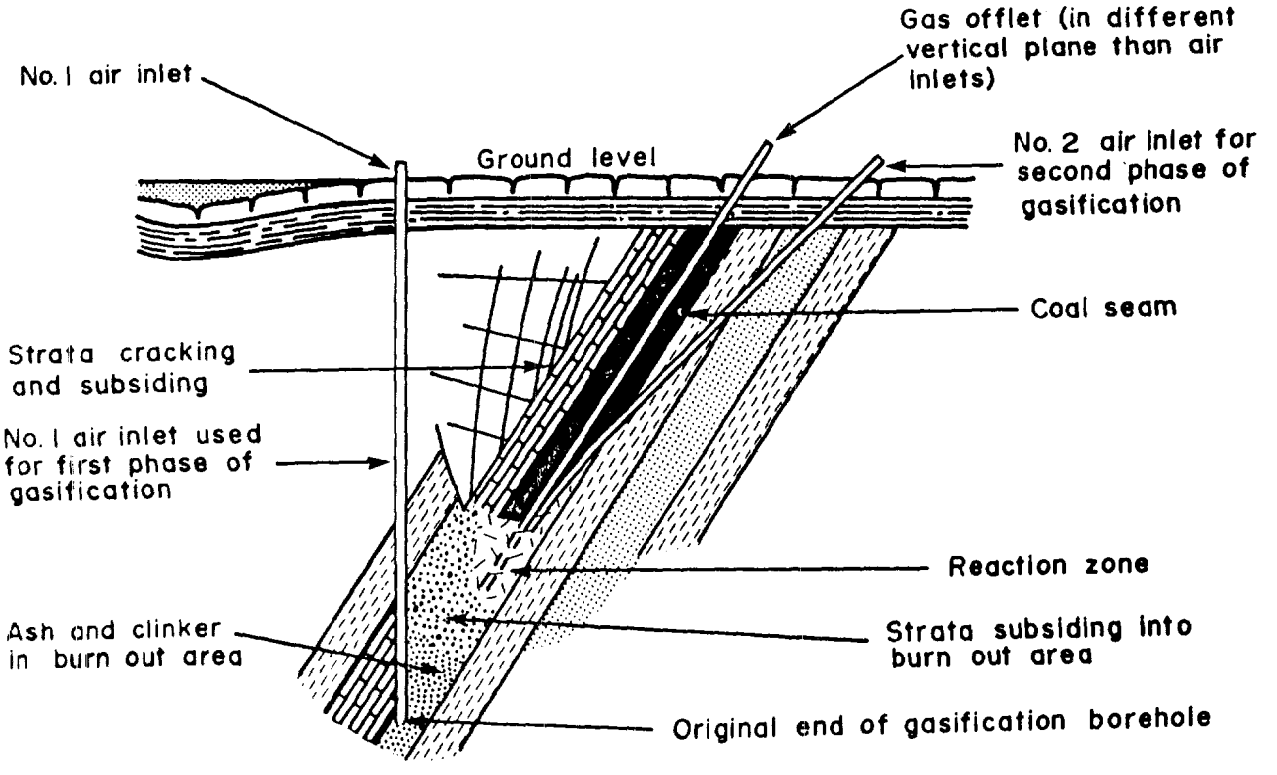

Figure 10.11. Conceptual diagram of coal gasification in steeply dipping beds (Wieber and Sikri, 1977)

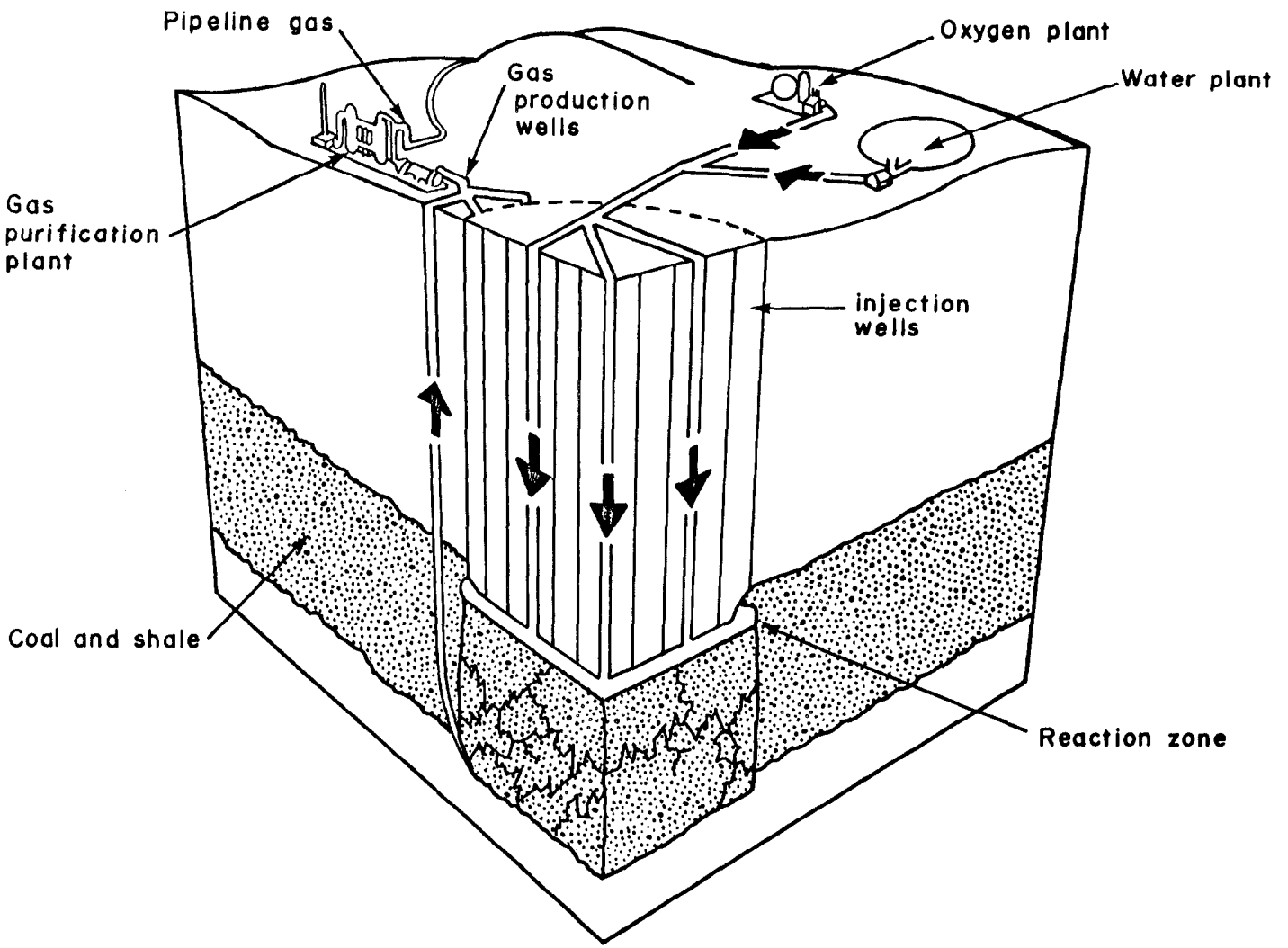

Figure 10.12. Conceptual diagram of packed bed coal gasification (Wieber and Sikri, 1977)

been used with varying success; further study in well design and construction is being made during the technology research and development process. Retort conditions do not expose the wells to high pressures although high temperatures are encountered. Specific design requirements will be available as more experimental retorts are developed.

Well design is different in true in-situ retorting. The wells are actually drilled into the shale or the retort zone. The wells are cased to the top of the shale bed and are cemented to the surface. The specific design of the wells depends on the depth of the resource and the selected fracturing techniques (Jee, et al., 1977); however, additional research and development activities will determine the final design characteristics. The longevity of the access wells in a high-temperature environment should be determined as part of this process.

Subsidence of retorts could impact the integrity of injection wells. The production of large volumes of shale from continuous beds could lead to caving or compaction and ultimately, subsidence. Short-term subsidence could cause disruption of the injection wells in the retort zone. Long-term subsidence propagated to the surface could lead to further disruption of injection wells and other wells in the area (Rothman, 1975).

Coal

In-situ coal conversion wells are completed in high-temperature combustion zones and are exposed to subsidence. These wells are subjected to temperatures of up to 2735°F (1500°C) for several hours. During ignition, the base of the injection well will undergo an initial thermal cycle reaching as high as 1112°F (600°C). Combustion of coal in the vicinity of any commonly used casing material (carbon steel) will cause its rapid deterioration, by sulfidation, oxidation, and melting. High temperatures also cause problems with surface valves and wellheads. Structural failure can result from thermal expansion of the casing. During the receding portion of the thermal cycle, contraction forces can exceed the ultimate strength of the casing and cause rupture. In addition, overburden drying generally causes the cement bond to shrink and part, creating leakage paths to upper level aquifers and eventually

to the surface (Hill, et al., 1978 and 1980). High temperature cements and special casing materials are under experimentation.

The potential failure modes noted have been partially addressed in the design of the well shown schematically in Figure 10.13. The highlights of this design include: an improved high-temperature resistant cement for casing emplacement; a casing liner installed through the length of the well and suspended from the wellhead flange with the lower end unsupported allowing free vertical movement; the annulus formed between liner and casing provides an insulating barrier between process gases and the casing; the lower section of the liner assists in protecting the well from exposure to high temperatures; and the liner serves as insurance against casing failure by enhancing the reliability of the well to serve as a conduit with the coal seam reaction zone (Hill, et al., 1979).

10.5 GEOTHERMAL ENERGY DEVELOPMENT

10.5.1 Description of the Practice

The four principal geothermal resource areas being commercially developed or researched are hydrothermal (hot-water), geopressured, hot dry rock, and dry steam. Exploration of these diverse resources involves innovative technologies and presents different demands on injection-well design and construction (Glorioso, 1980).

Nearly all commercial electric power generated from geothermal sources is from the Geysers field in northern California and is of the vapor-dominated or dry-steam variety. The only other large scale geothermal electrical power produced in the United States is a hydrothermal/geothermal demonstration. Plants are under development throughout the United States, but are not yet producing electrical power commercially.

Known and potential hydrothermal resources of the nation are indicated in Figure 10.14. Most of the high-temperature prospects are located in the western states and have the most potential for electrical-power generation. However, lower grade [less than 194°F (90°C)] geothermal

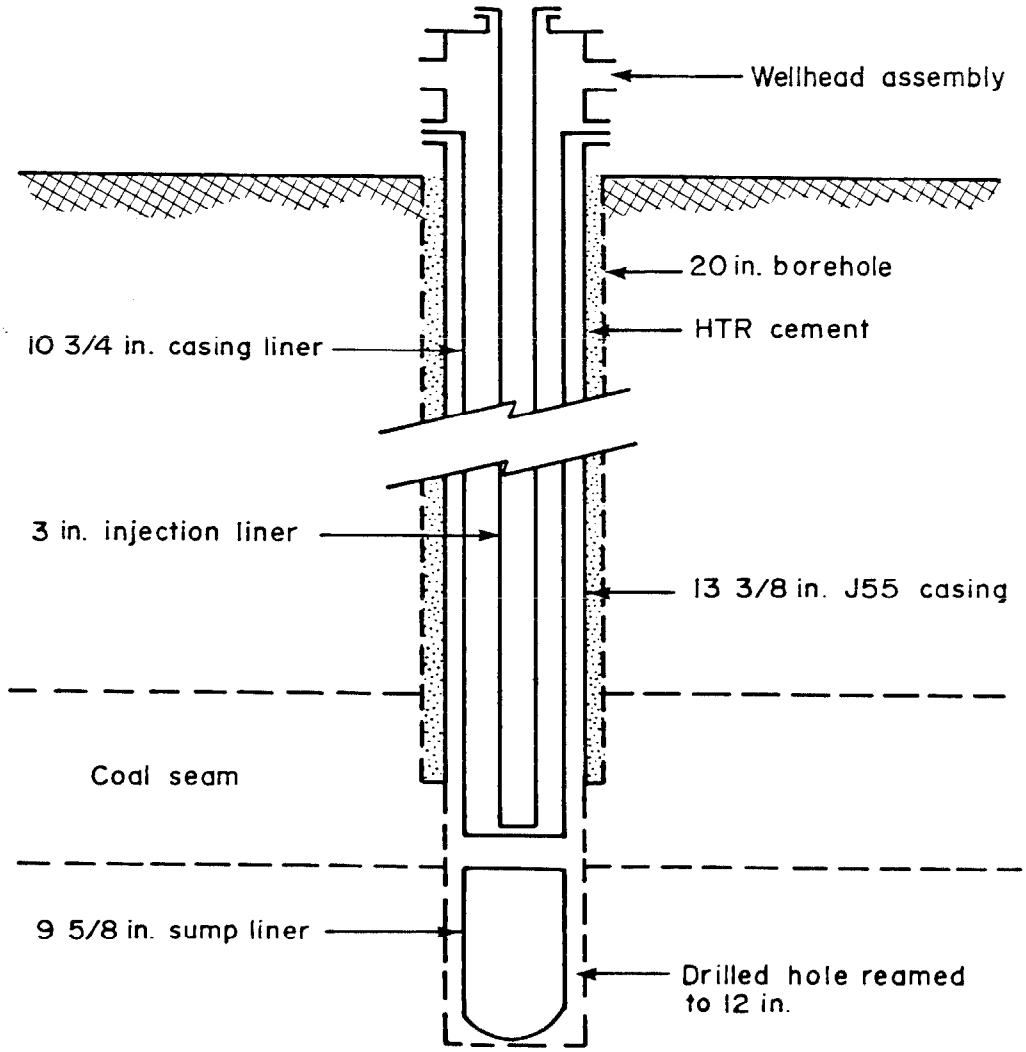

Figure 10.13. Schematic diagram of an in-situ coal conversion well (Hill, et al., 1979)

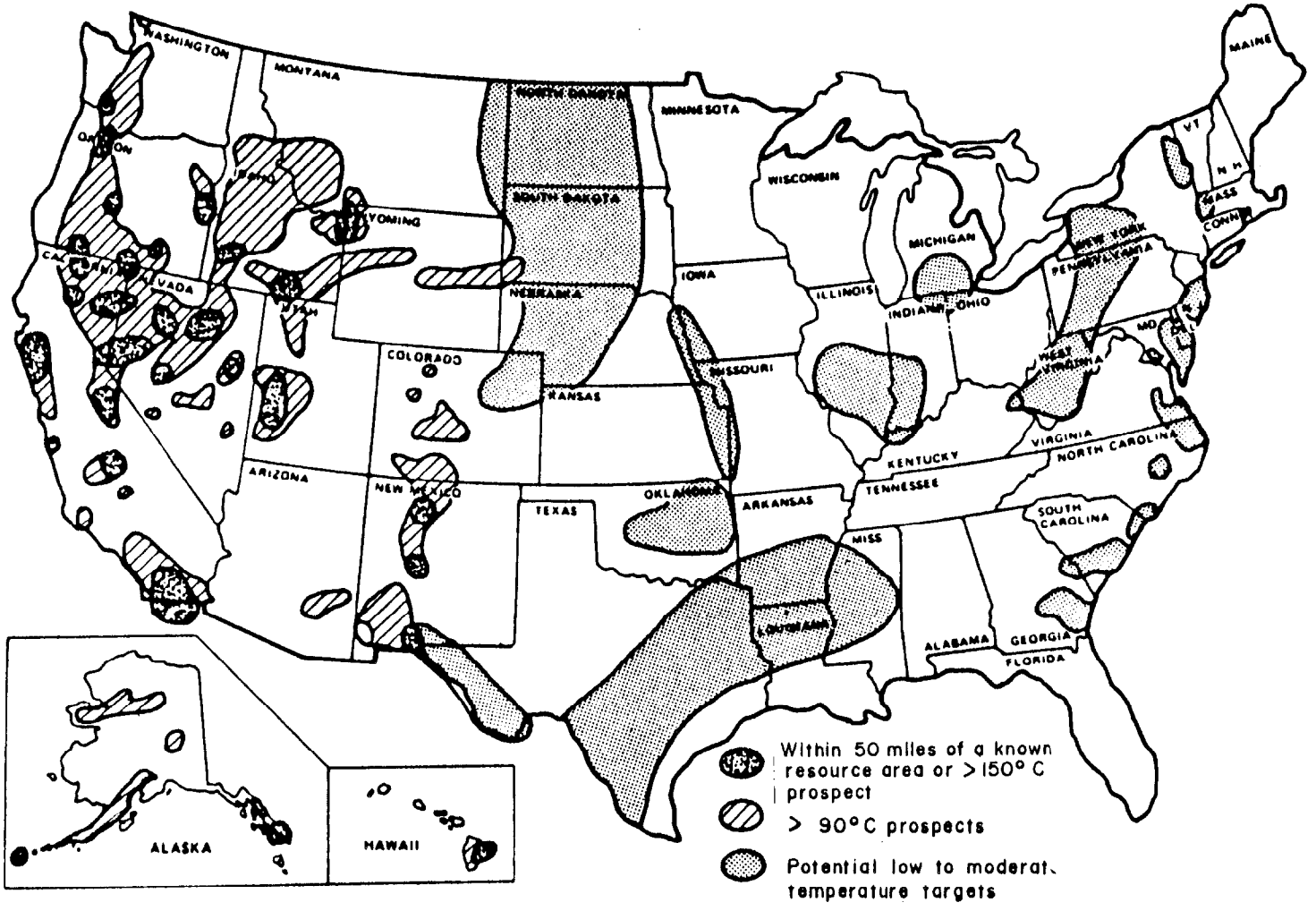

Figure 10.14. Known and potential hydrothermal resources (DOE, 1980)

resources may be useful in direct-heat applications, the most rapidly developing area of geothermal energy.

Geopressured geothermal resources are found in sedimentary basins in which abnormally high temperatures 248°F to 347°F (120°C 175°C) and pressures [9,000 to 15,000 psi (6.2×10^7 to 1.0×10^8 N/m^2)] are found (Figure 10.15). Fluids from these zones also contain large amounts of methane that may be economically recoverable. Current research and development plans are considering a combined program of methane, hydromechanical, and hydrothermal energy recovery. However, the development potential is not proved and the commercial potential is uncertain (Wallace, et al., 1978; U. S. Department of Energy, 1981; Dorfman and Deller, 1976; House, 1975).

The hot dry rock geothermal resource consists of the heat stored in rocks that contain insufficient water to transport heat to the land surface. The concept is illustrated in Figure 10.16, and involves drilling into the hot rock zone, developing permeability through fracturing, and circulating a heat-transfer fluid, usually fresh water, through a heat-exchanger in a closed loop configuration. This process is currently in the research and development stage. The resource base for hot dry rock systems is potentially large.

Injection wells related to geothermal energy development are used for various purposes and, consequently, have differing design characteristics. In hydrothermal reservoirs, produced waters are commonly reinjected into the original reservoir to maintain pressure and to limit formation compaction. These pressure maintenance wells are similar in purpose to those used in secondary oil recovery. Depending on geothermal or reservoir engineering requirements, produced fluids may be disposed of in other strata. Waste-disposal wells may also be used in disposal of condensate from geothermal power plants. Geopressured resource development also requires the disposal of large quantities of fluid, usually in an overlying formation. Pressure maintenance wells also have been considered in geopressured aquifer development. Development of hot dry-rock systems requires wells to inject the heat-exchange fluid into the thermal area.

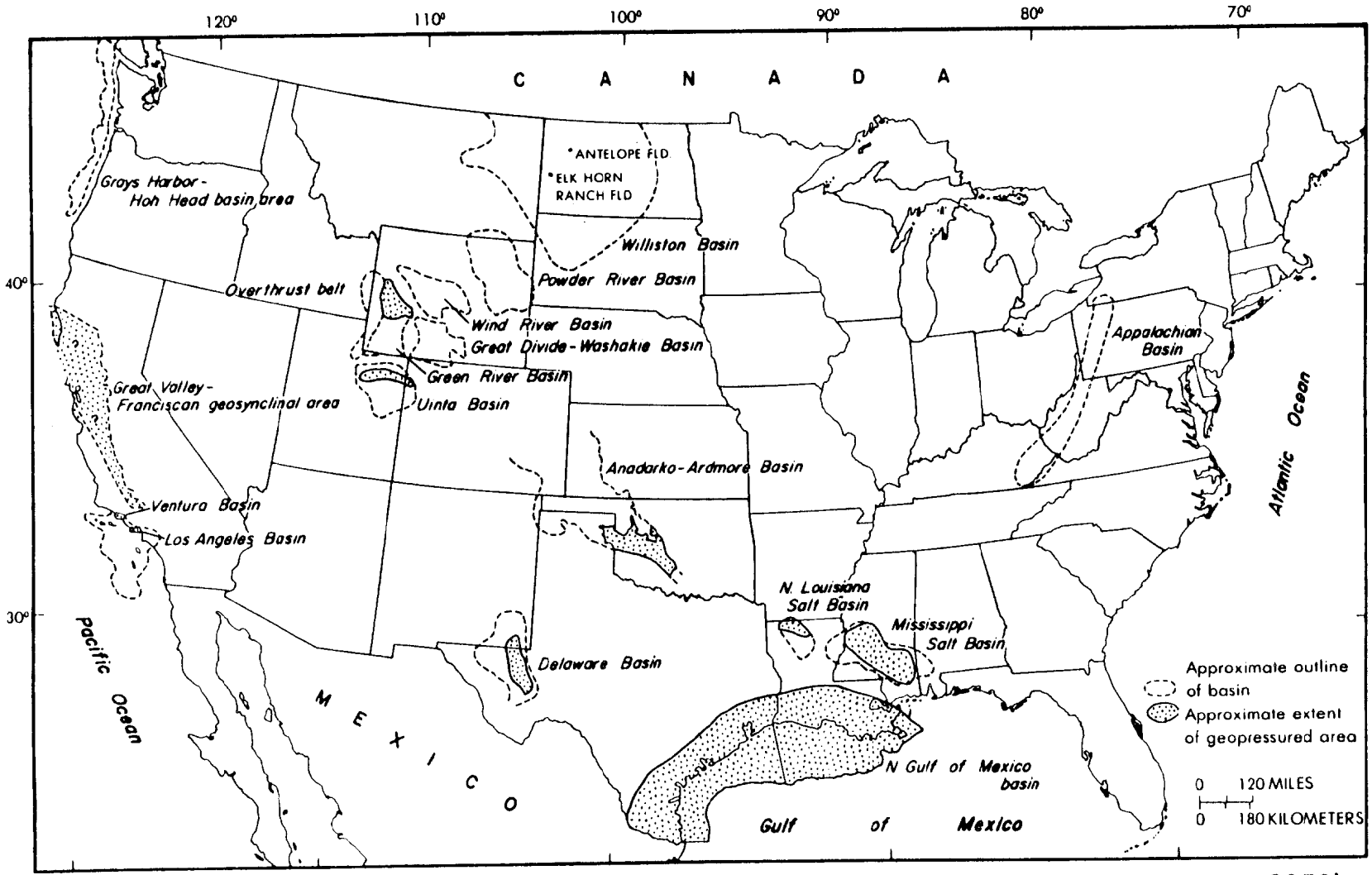

Figure 10.15. Geopressured basins in the United States (Wallace, et al., 1978)

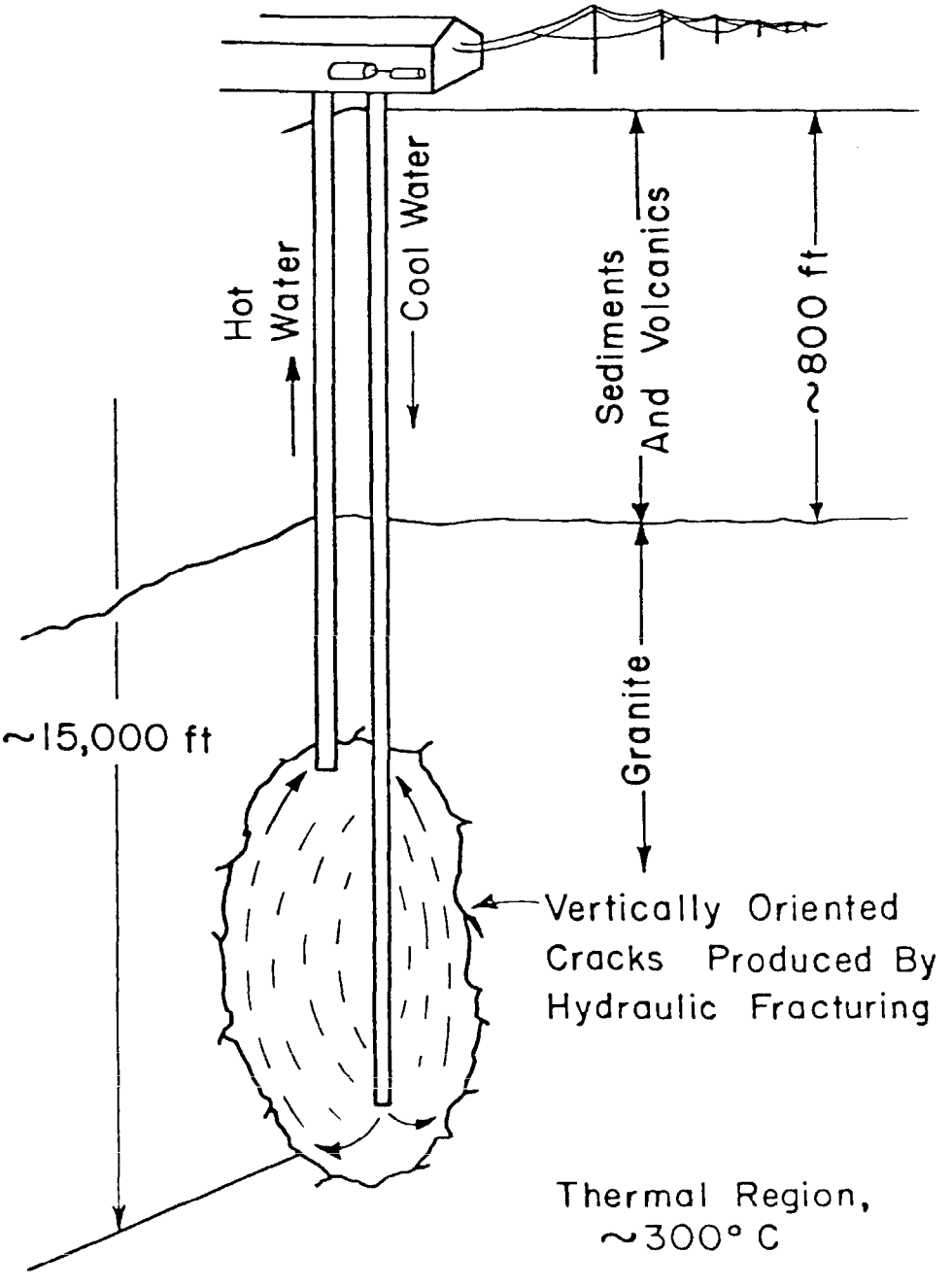

Figure 10.16. Conceptual diagram of a dry rock geothermal energy recovery (AEC, 1973)

10.5.2 Well Design

Well design elements are closely related to the geothermal practice and the nature of the fluids. The chemical make-up of geothermal and geopressured fluids is likely to contribute to corrosion and scaling of well casings. In fact, disposal wells may be more prone to corrosion than production wells since the fluids pick up oxygen from exposure to air in the power plant. Research is being performed to develop corrosion-resistant metals for geothermal energy development (Eliezer, et al., 1979; Defferding, 1980).

Geothermal and geopressured brines contain up to 325,000 ppm of total dissolved solids, including carbonates and sulfates of calcium, strontium, and barium. Erosion of tubing and casing can occur if these dissolved solids precipitate or if sand is present in the injection fluid (Bachman and Smith, 1979). Hydrogen sulfide is also present in many geothermal fluids at levels above concentrations regarded safe to structural stability (<2-5 ppm) which can be a potential problem in geothermal-disposal well construction, and should be reflected in material selection. High-strength materials are also more susceptible to sulfide cracking than less hardened steels (Defferding, 1980; Reed, 1975).

Material selection for use in geothermal disposal systems should also include consideration of the severe corrosiveness of brines to carbon-steel casing, and particularly to stress-corrosion cracking. Stress-corrosion cracking is the failure by cracking of a material that is under constant tensile stress. Crack propagation and failure may occur after only a few minutes or after months or years (Defferding, 1980).

Injection rates, pressures, temperatures and pretreatment must be optimized to maintain corrosion control, injectivity, and well competency. Factors beneficial in corrosion inhibition could adversely affect scaling which to some extent, mitigates corrosion by providing a protective barrier (Reed, 1975).

Drilling and casing methods must be specially adapted to hot geothermal or geopressured areas. In geopressured applications, blowout prevention equipment must be properly

installed as large pressure surges or kicks can occur if a geopressured zone is penetrated. Drilling equipment must include a cooling tower for drilling fluid as high temperature zones will result in fluid degradation and in lack of cooling properties when contacting formation walls.

In geothermal drilling and casing, most problems arise from high temperatures, lost circulation zones, and contamination of the cement. In general, cement should be installed to the surface on all casing strings. Uncemented casing can fail from thermal expansion and buckling when unsupported, or contract and pull apart when cooled (Shryock and Smith, no date). To mitigate expansion and contraction problems, casing should be selected that has a modulus of elasticity (or expansion potential) matched to the expected temperature of the fluid.

Cementing procedures and materials are critical in geothermal well design and construction. Some cementing materials may exhibit a satisfactory compressive strength when first set, but will begin to lose this strength when continually exposed to high temperatures. As this occurs, cement permeability will decrease until the cement column can no longer prevent communication. This phenomena requires the use of specialty cements or additives, such as silica flours (Shryock and Smith, n.d.).

Well completion methods must also allow for widely varied and high temperatures. Tubing expansion and contraction must be considered to prevent ballooning or helical buckling. Packers that depend on tubing weight or tension for setting strength can be unseated during expansion and contraction; an expansion receptacle is critical to prevent losing the seal. Additionally, special thermal-seal packers are designed for high temperature operation in corrosive conditions.

Figures 10.17 illustrates several designs of geothermal wells that can be used either for production or injection. The figures indicate the use of both liners and open hole configurations. Also, both tubing and packer and through casing injection may be employed.

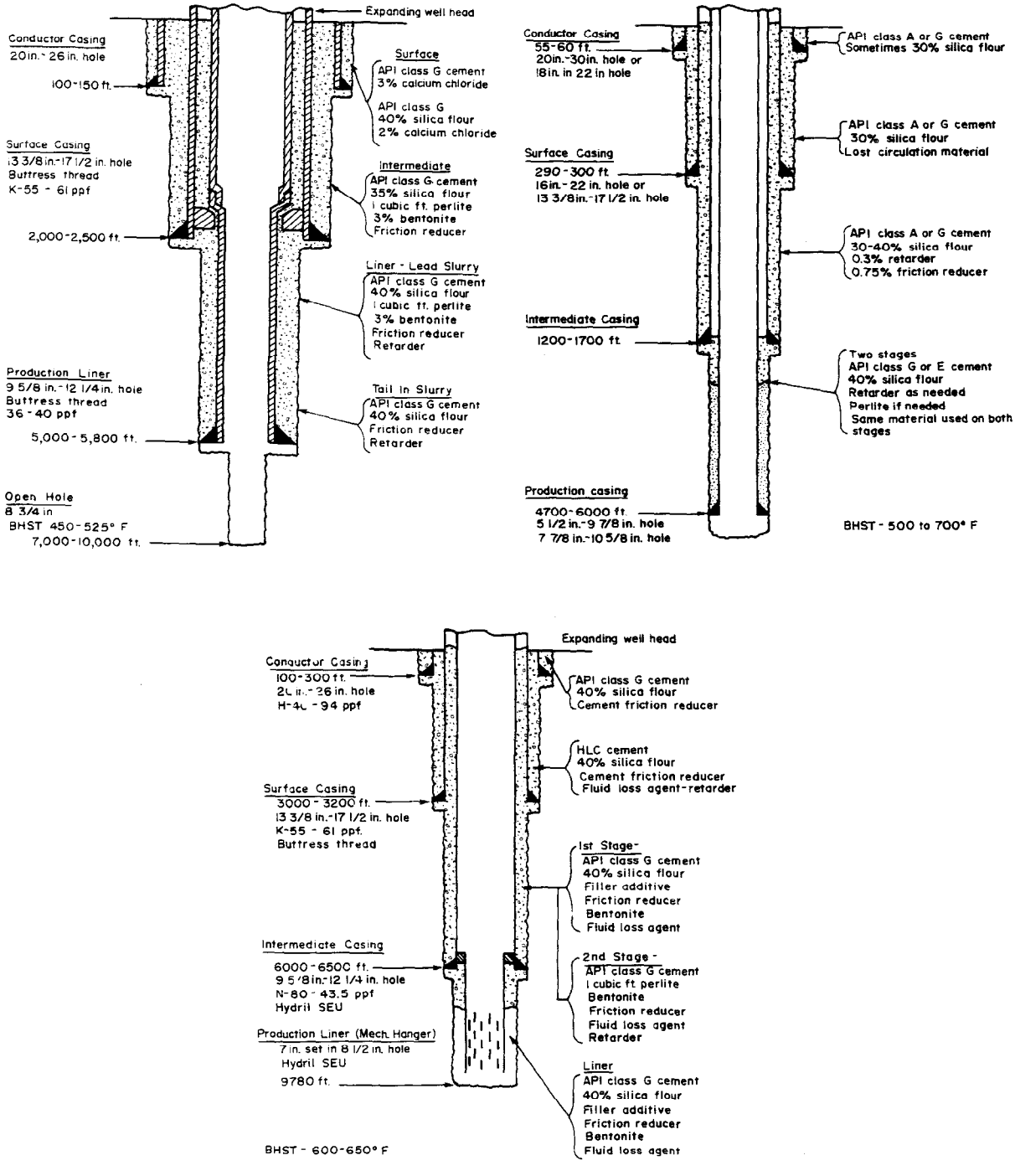

Figure 10.17. Design of geothermal energy wells (Shyrock and Smith, n.d.)

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