

FACTORS EFFECTING THE AREA OF REVIEW  
FOR HAZARDOUS WASTE DISPOSAL WELLS

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Abstract

The area of review, for a hazardous waste disposal well, is defined as the radial distance from the receiving well in which the pressure, caused by injection, increases sufficiently to possibly cause migration of fluids into useable sources of drinking water (USDW). Among the potential conduits for fluid migration from the disposal formation are improperly plugged well bores, channeling behind the casing of the injection well, faulted formations, solution channels, naturally fractured formations or facies pinch-outs. Usually faults, solution channels and most other naturally occurring geological conduits are filled with native fluids and are frequently sealed from USDWs by secondary mineralization. This paper concerns itself with only those conduits that are man-made.

Man-made conduits such as old abandoned test holes or oil and gas wells are sealed with cement plugs and drilling mud. The static mud column provides substantial resistance to upward flow. Most mud systems develop a gel structure when allowed to remain quiescent. To initiate flow up an improperly abandoned well bore, the pressure in the disposal zone must exceed the sum of the static mud column pressure and the mud gel strength pressure. If the sum of these values is not exceeded during the life of a hazardous waste disposal well, there is no potential for contamination of USDWs. This paper presents a simplified procedure which can be used to calculate that effected area.

Introduction

The area of review, for a deep injection well, is determined by the zone of endangering influence for the life expectancy of that well. The zone of endangering influence is defined as that area the radius of which is the lateral distance in which pressures in the injection zone may cause the migration of the injection and/or formation fluid into an underground source of drinking water (USDW).

Factors affecting this area of review are the radial extent of ground water movement from the well bore, the rate of pressure build-up in the reservoir, through time, at various distances from the well bore and the potential for upward migration of fluids through man-made conduits.

The prediction of the probable rate of pressure increase and radial fluid movement in the disposal reservoir, resulting from the injection of fluids is a problem often confronted by injection well operators and regulatory agencies. Fluid injected into a formation which is already liquid filled will result in an increase in pressure in that formation. This injected fluid must be accommodated by either one or a combination of the following; expansion of the pore space in the matrix rock, compression of either or both the formation and injected fluids or expulsion of the formation water.

The resulting increase in pressure in the receiving formation due to the injection of fluids pose potential environmental threats to our USDWs if any man-made conduits exist within the area of review. Among the potential conduits for fluid migration from the disposal formation are improperly plugged well bores, channeling behind the casing of the injection well, faulted formations, solution channels, naturally fractured formations or facies pinch-outs.

#### Factors Effecting the Area of Review

##### Area of Review

The radius of the area of review for an injection well is determined either by calculating the zone of endangering influence or by using a fixed radius from the well bore which ever is less. The distance of the fixed radius varies from state to state. In states where the Environmental Protection Agency (EPA) has primacy, the fixed radius is 1/4 mile, while in primacy states or states that set their own regulatory standards so long as they meet or exceed EPA standards, the fixed radius varies from 1/4 mile to 2-1/2 miles.

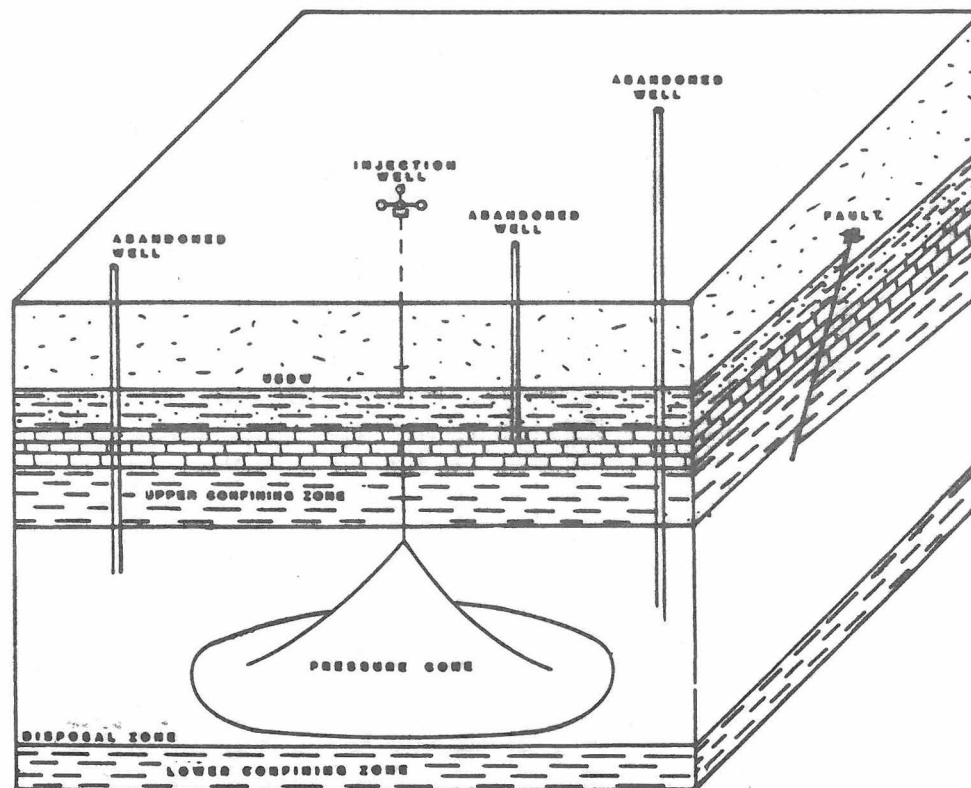
Computation of the zone of endangering influence should be calculated for an injection period equal to the expected life of the well. There are several equations that can be used for determining the area of review. The most notable and widely used is shown below (Barker, 1971; Ferris, et al, 1962; Kruseman and DeRidder, 1970; Lohman, 1972).

$$h = \frac{Q}{4\pi T} (-0.577216 - \log_e u + u - \dots - \frac{u^2}{2 \times 2!} + \frac{u^3}{3 \times 3!} - \dots) \quad (1)$$

where

$$h = \frac{r^2 S}{4Tt}$$

FIGURE 1  
SCHEMATIC SHOWING FACTORS  
AFFECTING THE AREA OF REVIEW



and

h = hydraulic head change at radius r and time t  
Q = injection rate  
T = transmissivity  
S = storage coefficient  
t = time since injection began  
r = radial distance from well bore to point of interest.

For large values of time, small values of radius of investigation, or both, Equation 1 can be reduced to:

$$\Delta h = \frac{2.30Q}{4\pi T} \log \frac{2.25Tt}{r^2 S} \quad (2)$$

Unfortunately, this equation does not address all the possible well configurations, multiple well systems, reservoir conditions, skin effects and other variables and combinations thereof. Warner, et al (1979) posed the use of several equations based on specific conditions of the system being evaluated. They indicated that an adequate approximation of the pressure build-up caused by injection into infinite confined reservoirs can be determined if we assume

1. Flow is horizontal.
2. Gravity effects are negligible.
3. The reservoir is homogeneous and isotropic.
4. The injected and reservoir fluids have a small and constant compressibility.
5. The receiving reservoir is infinite in areal extent and is completely confined above and below by impermeable beds.
6. Prior to injection the piezometric surface in the vicinity of the well is horizontal, or nearly so.
7. The volume of fluid in the well is small enough so that the effect of the wellbore can be neglected.
8. The injected fluid is taken into storage instantaneously. That is, pressure effects are transmitted instantaneously through the aquifer.

The basic differential equation for the unsteady radial flow of a slightly compressible fluid from an injection or other type well is (Matthews and Russell, 1967)

$$\frac{\partial^2 P}{\partial r^2} + \frac{1}{r} \frac{\partial P}{\partial r} = \frac{\phi u c}{k} \frac{\partial P}{\partial t} \quad (3)$$

where:

| Symbol | Parameter or Variable | Practical Units   |
|--------|-----------------------|-------------------|
| c      | compressibility       | psi <sup>-1</sup> |
| Q      | porosity              | decimal fraction  |
| h      | reservoir thickness   | feet (ft)         |
| k      | permeability          | millidarcies (m)  |
| u      | viscosity             | centipoise (cp)   |

|   |                 |                                |
|---|-----------------|--------------------------------|
| p | pressure        | psi                            |
| q | flow rate       | stock tank barrels/day (STB/D) |
| r | radial distance | feet (ft)                      |
| t | time            | days (D)                       |

The pressure build-up equations used by Warner, et al (1979) were written using dimensionless pressure ( $P_D$ ) and dimensionless time ( $t_D$ ). These dimensionless quantities are groups of variables that commonly occur in build-up equations and can be conveniently replaced by a single term. Dimensionless time, for the units listed above is:

$$t_D = \frac{6.33 \times 10^{-3} kt}{\phi \mu c r^2} \quad (4)$$

In unsteady state or transient flow equations, dimensionless pressure ( $P_D$ ) is a function of dimensionless time and, perhaps, other quantities, depending on the particular buildup solution. It is defined for each equation in which it is used, throughout the Warner report.

The Warner equations presented all contain the variable  $\beta$ , the formation volume factor, which is the ratio of the volume of the fluid being injected at reservoir pressure compared with the volume at standard conditions (520°R, 14.7 psi). For liquids,  $\beta$  can, for practical purposes, be considered to be 1.0, as in all examples in this report. However,  $\beta$  is quite variable when the injected fluid is gas. When a highly compressible fluid is being injected,  $\beta$  should be evaluated at an average reservoir pressure. In cases where the pressure is not known, enter a value of  $\beta = 1.0$ , obtain the approximate pressure, then evaluate  $\beta$  (Amyx, et al, 1960) and recalculate the pressure.

#### Multiple Well Effects

As indicated in Figure 2, if we assume a constant injection rate for a single well penetrating the entire receiving aquifer, and adjust for practical units, the differential equation, Equation 3, has a solution of the form

$$P_r = P_i + 70.6 \frac{q \mu \beta}{kh} [Ei \left( \frac{39.5 \phi \mu c r^2}{kt} \right)] \quad (5)$$

and for the case where  $1/t_D < 0.01$ . This is approximated as

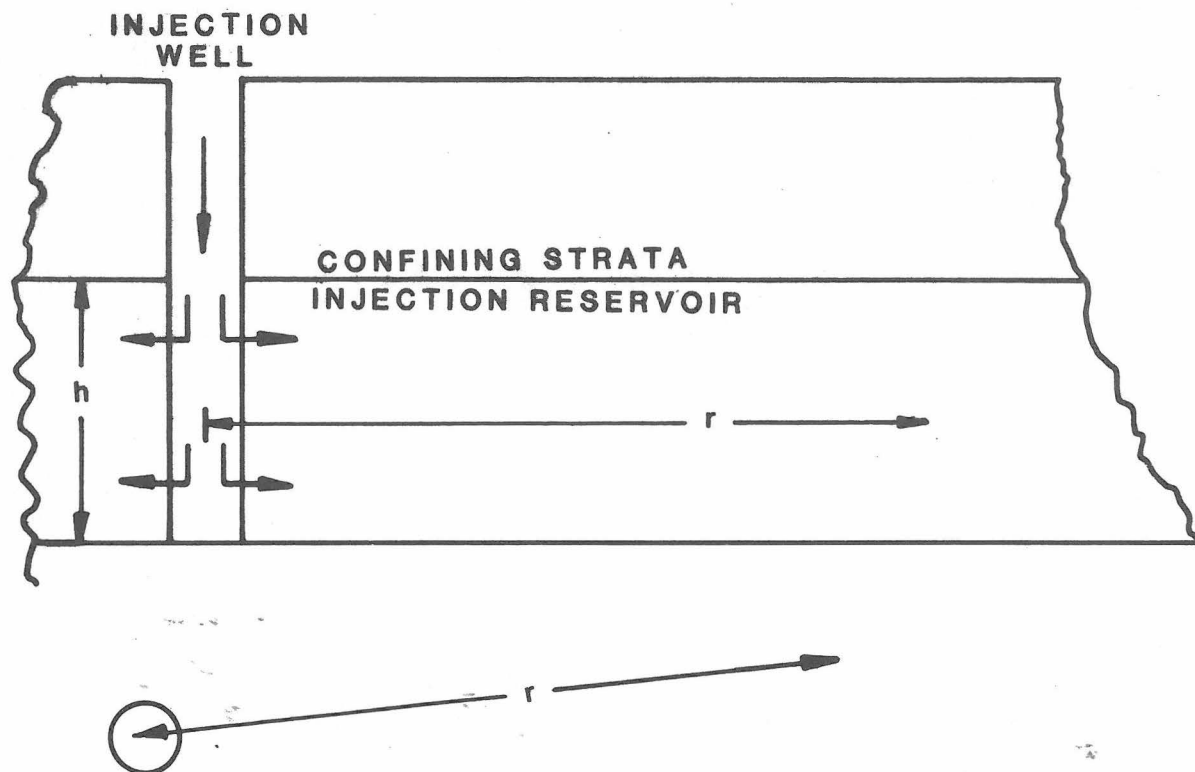
$$P_r = P_i + 162.6 \frac{q \mu \beta}{kh} \log \left( \frac{kt}{70.4 \phi \mu c r^2} \right) \quad (6)$$

where

FIGURE 2

PROFILE AND PLAN VIEWS OF A COMPLETELY  
PENETRATING WELL INJECTING INTO A CONFINED  
RESERVOIR. PRESSURE IS TO BE CALCULATED  
AT A POINT  $r$  DISTANCE FROM THE WELL.

(FROM WARNER, et.al. 1979)



| <u>Symbol</u> | <u>Parameter of Variable</u>        | <u>Practical Units</u>    |
|---------------|-------------------------------------|---------------------------|
| $\beta$       | formation volume factor             | Std Stk Tank BBL (RB/STB) |
| $P_r$         | reservoir pressure<br>at radius $r$ | psi                       |
| $P_i$         | initial reservoir<br>pressure       | psi                       |

A convenient characteristic of these equations (Warner, 1979) is that the effects of individual wells can be superimposed to obtain the combined effect of multiple wells. As indicated in Figure 3, the pressure at any given point in a reservoir can be evaluated by summing the pressures caused by each of the individual injection wells. Assuming the same criteria as in Equations 4 and 5 above, except for multiple wells, we have

$$P_r = P_i + 70.6 \left[ \sum_{n=1}^m \frac{q_n \mu_n \beta_n}{k_n h_n} Ei \left( \frac{39.5 \phi_n \mu_n c_n r_n^2}{k_n t_n} \right) \right] \quad (7)$$

where  $n$  is the well number.

For cases where  $1/t_d < 0.01$ , an adequate approximation is

$$P_r = P_i + 162.6 \left[ \sum_{n=1}^m \frac{q_n \mu_n \beta_n}{k_n h_n} \log \left( \frac{k_n t_n}{70.4 \phi_n \mu_n c_n r_n^2} \right) \right] \quad (8)$$

If we assume a variable injection rate for the same criteria as previously applied, the applicable equation is

$$P_r = P_i + 70.6 \left[ \sum_{a=1}^n \frac{(q_a - q_{a-1}) \mu \beta}{kh} Ei \left( \frac{39.5 \phi \mu c r^2}{k(t - t_{a-1})} \right) \right] \quad (9)$$

For cases where  $1/t_d < 0.01$

$$P_r = P_i + 162.6 \left[ \sum_{a=1}^n \frac{(q_a - q_{a-1}) \mu \beta}{kh} \log \left( \frac{k(t - t_{a-1})}{70.4 \phi \mu c r^2} \right) \right] \quad (10)$$

where  $a$  is the time interval under consideration and  $q_a$  is the rate during that time interval.

These equations are based on the principle of superposition. That is, the pressure effects begin with the initial injection period  $t_1$  and rate  $q_1$ . When a new rate  $q_2$  is implemented, it is as if a new well begins to operate at that rate, with the effects superimposed on the original well, while the original well continues to operate at rate  $q_1$ . This performance is shown diagrammatically in Figure 4.

FIGURE 3

PROFILE AND PLAN VIEWS OF TWO COMPLETELY PENETRATING WELLS  
INJECTING INTO A CONFINED RESERVOIR. PRESSURE IS TO BE CAL-  
CULATED AT A POINT AT RADII  $r_1$  AND  $r_2$  FROM WELLS 1 AND 2  
RESPECTIVELY.

( FROM WARNER, et.al. 1979 )

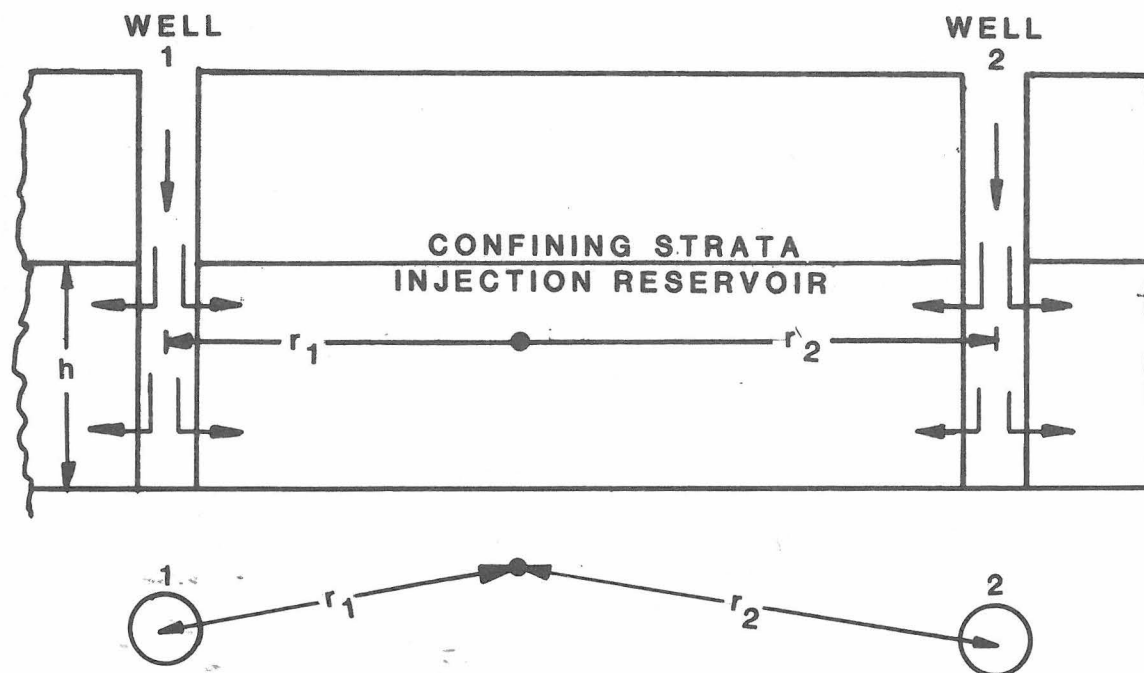
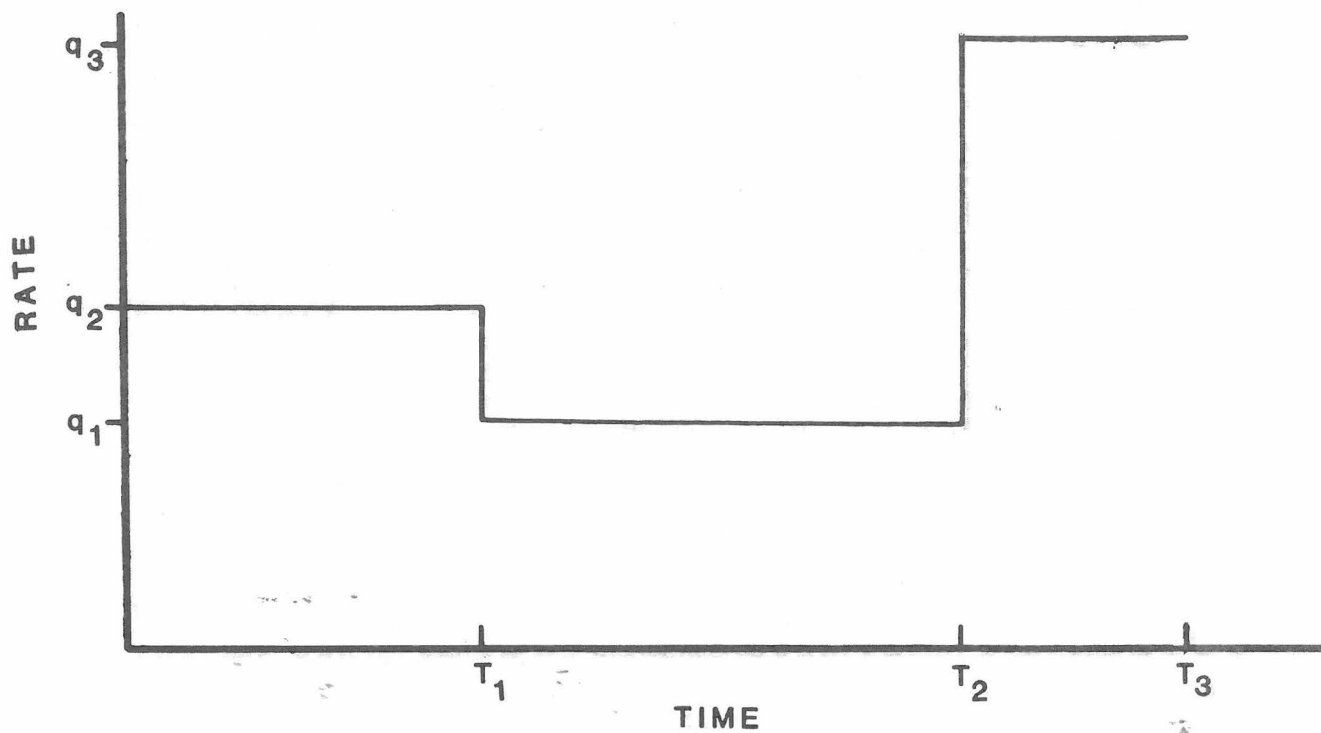


FIGURE 4  
DIAGRAMMATIC REPRESENTATION OF THE INJECTION  
HISTORY OF AN INJECTION WELL OPERATING AT A  
VARIABLE RATE,  
(FROM WARNER, et.al. 1979)



In computing the pressure buildup caused by multiple injection wells operating at variable rates, the principle of superposition is applied twice, once for computation of the pressure effects of each well and a second time in summing the effects of the individual wells. Figure 2 depicts two wells whose effects must be summed and Figure 3 shows a possible pattern of variable rate injection that might exist.

The applicable equation is:

$$P_r = P_i + \left[ \sum_{b=1}^m \sum_{a=1}^n \frac{70.6(q_{ba} - q_{b(a-1)})}{k_b h_b} \text{Ei} \left( \frac{39.5 \phi_b \mu_b c_b r_b^2}{k_b (t_b - t_{b(a-1)})} \right) \right] \quad (11)$$

Where  $b$  is the well number,  $a$  is the time interval under consideration for well  $b$ , and  $q_{ba}$  is the rate for well  $b$  during time interval  $a$ . For cases where  $1/t_d < 0.01$ , an adequate approximation is:

$$P_r = P_i + \left[ \sum_{b=1}^m \sum_{a=1}^n \frac{162.6(q_{ba} - q_{b(a-1)})}{k_b h_b} \log \left( \frac{k_b (t_b - t_{b(a-1)})}{70.4 \phi_b \mu_b c_b r_b^2} \right) \right] \quad (12)$$

In summary, these two equations state and perform the calculation for each well, as done for the single-well variable-rate case and then sum the effects of the wells.

### Skin Effects

Warner, et. al. (1979) also addressed the effects of skin damage. Injection wells may suffer permeability loss in the vicinity of the wellbore during construction or operation or they may experience permeability gain. Permeability loss can result from drilling mud invasion, clay-mineral reactions, chemical reactions between injected and aquifer water, bacterial growth, etc. Permeability gain can result from chemical treatment such as acidization or from hydraulic fracturing and other mechanical stimulation methods. These permeability changes, which occur in the immediate vicinity of the wellbore are called "skin effects" by the petroleum industry and are described by a "skin factor" (van Everdingen, 1953; Hurst, 1953). The skin factor ( $s$ ) is positive for permeability loss and negative for permeability gain.

The skin factor can vary from about  $-5$  for a hydraulically fractured well to  $+\infty$  for a well that is completely plugged (Earlougher, 1977). The incremental pressure difference caused by the skin effect is described by:

$$\Delta P_s = s \frac{q}{2\pi kh} \quad (13)$$

Equation 13 is applied by combining it with equations that are derived for pressure buildup without skin effects. For example, Equation 5 is rewritten below to include skin effects:

$$P_r = P_i + \frac{70.6q\mu\beta}{kh} \left[ Ei \left( \frac{39.5\phi\mu cr^2}{kt} \right) + 2s \right] \quad (14)$$

When  $1/t_d < 0.01$ , an adequate approximation of Equation 14 is:

$$P_r = P_i + 70.6 \frac{q\mu\beta}{kh} \left[ \ln \left( \frac{kt}{70.4\phi\mu cr^2} \right) + 2s \right] \quad (15)$$

Equations 14 and 15 are only valid at the wellbore. No equations are presented here for calculation of pressure buildup near the wellbore, in the zone of damage or improvement, because this zone is relatively thin and because the calculations are of relatively limited application. Outside of the skin zone, the standard equations can be applied with no correction (Earlougher, 1977). The thickness of the skin is determined by (Hawkins, 1956):

$$r_s = r_w e^{s k_s / k - k_s} \quad (16)$$

Seldom if ever, will  $k_s$  be known. Reasonable estimates of  $k_s$  can, however, be made to allow calculation of the range of possible skin thicknesses. Consideration of the sources of permeability reduction around a wellbore indicates that, in the case of wellbore damage,  $r_s$  would seldom be greater than a few feet. The radius of permeability improvement can be greater, in the tens of feet for an ordinary hydraulic fracturing program, but probably less than 100 feet as the maximum  $r_s$ , except in cases of massive hydraulic fracturing.

It should be noted that these equations can only be used for pressure buildup at the well. As discussed above,  $s$  is assumed to be zero and the ordinary buildup equations should be applied for points outside of the skin zone, which is estimated by Equation 16 or assumed to be less than 100 feet, if Equation 16 can not be used.

It is generally assumed, in estimating the pressure effects of injection wells, that the wells will be drilled completely through the injection reservoir. This will usually be true, since it maximizes the injection efficiency of the well. However, for mechanical or geological reasons, drilling is sometimes stopped before complete penetration of the reservoir has been achieved. Such wells are described as partially penetrating. In other cases, a well may be drilled completely through a reservoir, but only a part of the reservoir is completed for injection. Figure 5 depicts partially penetrating and partially completed wells. The equation for pressure buildup as a result of injection into (pumping from) such a well (Hantush, 1964; Witherspoon, et al, 1967) is:

$$P_r = P_i + P_{DPP} \left( \frac{141.2q\mu\beta}{\phi\mu cr^2} \right) \quad (17)$$

where:

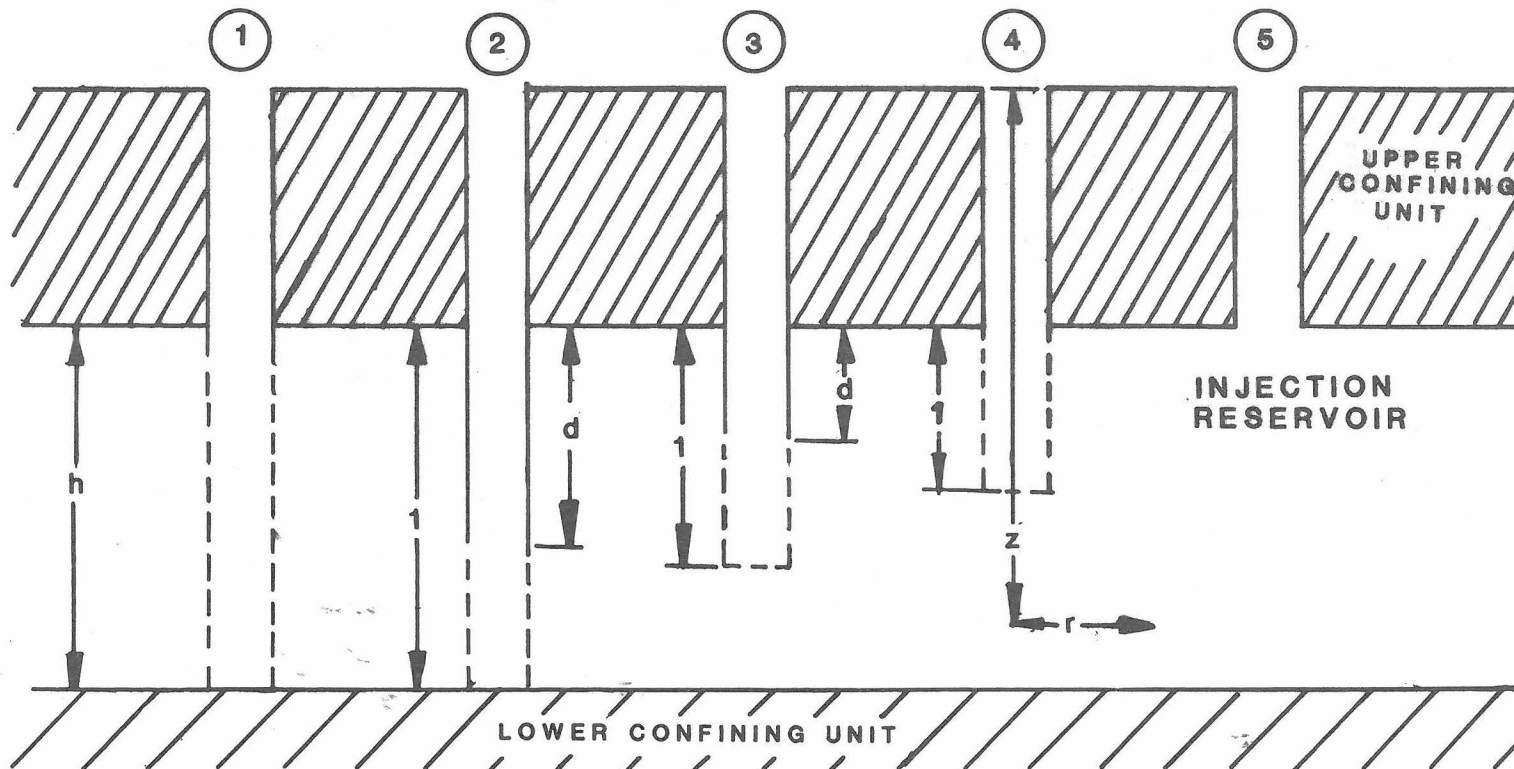
$$P_{DPP} = \frac{1}{2} \left[ Ei \left( \frac{1}{4t_D} \right) + f(r, h, l, d, z) \right]$$

FIGURE 5

WELLS WITH VARYING DEGREES OF PENETRATION AND COMPLETION

1. FULLY PENETRATING FULLY COMPLETED WELL.
2. FULLY PENETRATING PARTIALLY COMPLETED WELL.
3. PARTIALLY PENETRATING PARTIALLY COMPLETED WELL.
4. PARTIALLY PENETRATING FULLY COMPLETED WELL.
5. NON-PENETRATING WELL.

(FROM WARNER, et.al. 1979)



Partial penetration results in greater pressure buildup (decline) at and near the wellbore than would be experienced in a fully penetrating well for the same injection (pumping) rate. The magnitude of difference depends on the degree of penetration,  $l$ ; the ratio of the radius of investigation to aquifer thickness,  $r/h$ ; the length of the completed interval,  $l-d$ ; and the vertical point of investigation,  $z$ . The expanded form of Equation 17 is too complex for practical use by hand and the number of variables so large that it is impractical to provide tables for evaluation of  $P_{Dpp}$ . Computer programs have been developed to solve Equation 17 by Warner, et al (1979).

Warner, et al (1979) also addressed the effects of fractured reservoirs, infinite semiconfined reservoirs, bounded reservoirs, reservoirs with variable permeability, reservoirs with radially varying permeability and fluids of variable viscosity. Although all these possibilities may effect pressure buildup within a reservoir and therefore, the area of review, their specific values are rarely known. Normally these values can only be determined through well testing utilizing pressure buildup and fall off or step rate injection testing. Reasonable estimates can normally be made with the aforementioned equations and adjusted for these parameters after operating the system for a reasonable period of time.

### Criteria for Eliminating Potential USDW Contamination through Geological Barriers

#### Geohydrological Factors

Several geohydrological factors must be considered when studying the area of review for deep well injection. The subsurface environment is a complex physical and chemical system. Before the injection of fluids into this system can be permitted, it must be evaluated for its ability to contain the wastes. Upward migration of wastes can occur through either natural geologic or man-made pathways. Natural geologic conduits such as faults, solution channels or fractures are usually filled with native fluids and are frequently sealed from USDWs by secondary mineralization. Man-made conduits such as old abandoned test holes or oil and gas wells are sealed with cement plugs and drilling muds. However, the chemical effects of the injected waste on the formation rock and conduits, if any, must also be evaluated. When evaluating these phenomena, we must remember that chemical reactions in the subsurface are normally very slow and equilibrium is reached very quickly. Since fluid movement in the subsurface is very slow, diffusion is the primary mixing factor and provides additional support to waste containment near the well bore. If we consider all the rocks that are commonly penetrated when a well is drilled, the rock most susceptible to blocking both artificial and natural conduits is shale. Both sandstones and carbonate rocks can become unstable, and fill a well bore or annular space when subjected to tectonic stresses or when the hydrostatic mud pressure is lower than the pressure on the fluids within the rocks, particularly when the permeability is low. The instability of shale, on the other hand, is compounded by the extraordinary manner that this rock is affected when exposed to water.

## Reaction of Shales and Clays

Shales are essentially rocks that contain clay. Shale rocks are formed by the compaction of sediments. Water is squeezed out as sediments are buried deeper by layers deposited progressively during geologic time. The degree of compaction of the sediments is proportional to the depth of burial, provided the water is able to escape easily to permeable strata. The younger sediments soften and disperse when mixed with water. The older shales usually have undergone diagenesis, may remain hard and are less easily dispersed into water. The term shale is applied to everything from clays to lithified materials such as slate. Soft clays are extremely reactive with water while slates are relatively inert. Because the various shales behave differently upon exposure to drilling fluids when penetrated by the bit, it is useful to classify shales so that instability may be approached in a somewhat systematic manner. Such a classification is shown in Table I.

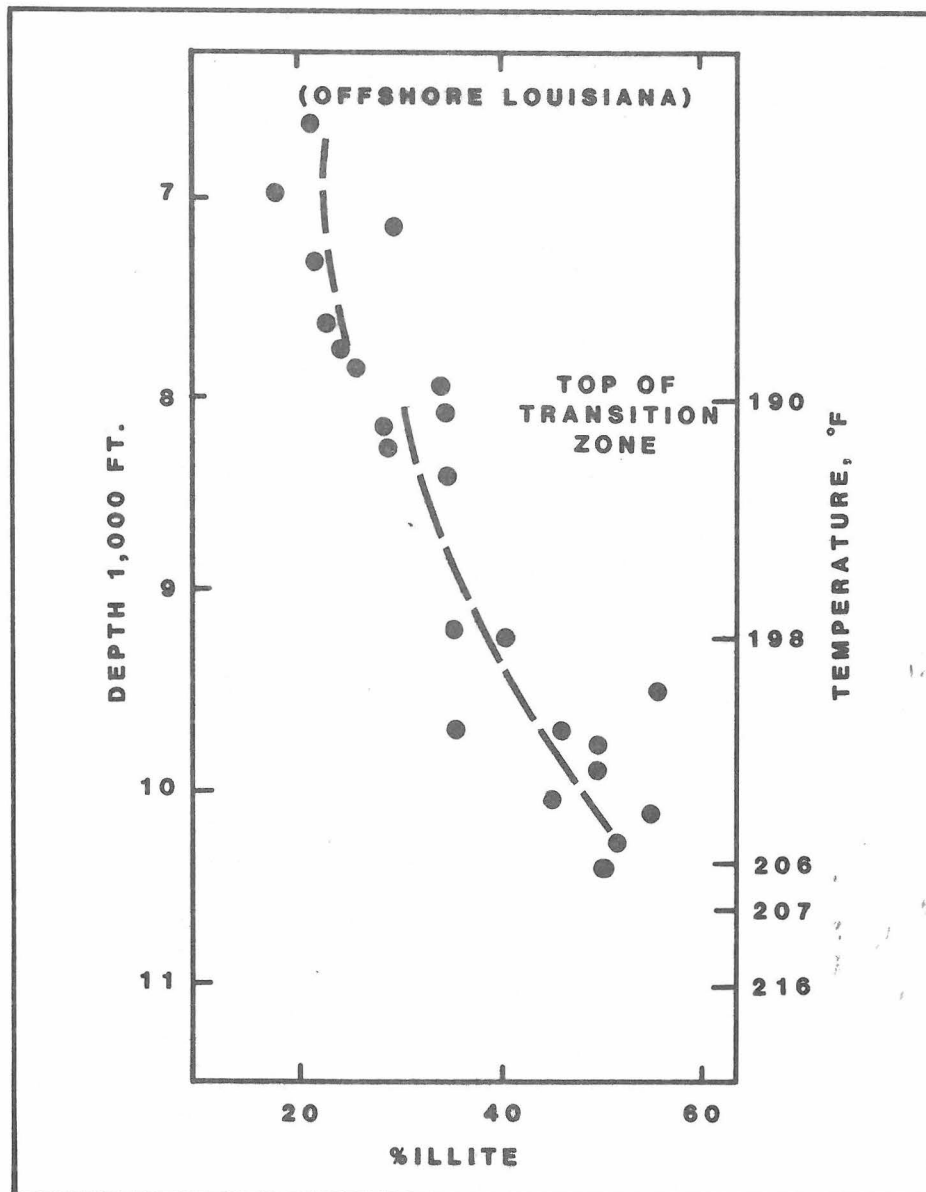
The amount of clay, the type of clay, the depth of burial, and the amount of water in a given shale all relate to the stability of the shale. The amount of clay in a given shale depends on the composition of the shale sediments at the time of deposition. The type of clay in a given shale depends not only on sediment composition at the time of deposition, but also on changes that may occur in the clay after burial.

From the view point of effect on hole stability, clays may be classified broadly as expandable and non-expandable. Expandable clays exhibit a high degree of swelling when wetted with water. Expandable clays as a group are called smectites. Montmorillonite (bentonite) is a high-swelling member of the smectite group. The non-expandable clay most commonly found in shales is illite. Chlorite and kaolinite are non-expandable clays often found in shales as well. Non-expandable clays swell much less than expandable clays on being wetted with water. The degree of swelling of both clay types varies greatly with the type and amount of salt dissolved in the water with which the clay is wetted (R.E. Grim, 1968).

The type of clay in younger sediments depends in large part on the temperature at depth of burial. A change in clay mineralogy with depth is illustrated in Figure 6 (W.H. Fertl and D.J. Timko, 1970). The increasing percentage of illite with depth is attributable to alteration of smectite to illite. The alteration phenomenon is called "diagenesis". Some water of crystallization is released from the expandable clay during diagenesis. Illite differs from montmorillonite structurally in that some of the silicons in the outer silicate layers (R.E. Grim, 1968) of illite are always replaced by aluminums, and the resultant charge deficiency is balanced by potassium ions (R.E. Grim, 1968). Temperature, rather than pressure, is thought to be the critical variable in the reaction through which this change is brought about.

The amount of water in a given shale depends on the depth of burial and the type of clay in the shale. Loosely bound water is squeezed out of the shale by pressure exerted by the weight of the overburden of the earth at depth of burial. A good approximation of the magnitude of overburden pressure is 1 psi/ft of depth. A laboratory experiment that illustrates

**FIGURE 6**  
**LATTICE MIXING**  
**(FROM FERTLANO AND TIMKO)**



this phenomenon is presented graphically in Figure 7 (H.C.H. Darley, 1969). Both bentonites in this illustration are expandable clays, and the Ventura shale contains mostly non-expandable clays. Most of the free water that can be easily squeezed out of the expandable clays is freed with a effective pressure of 2500 to 2000 psi. A matrix (grain to grain) stress of this magnitude would be expected in the crust of the earth at a depth of about 4500 to 5500 feet. Additional water is released as the swelling clays are subjected to even greater effective pressures.

#### Causes of Shale Instability

Shale instability may result from the following forces, either singly or in combination:

1. Overburden pressure
2. Pore pressure
3. Tectonic forces
4. Water adsorption
  - a. Dispersion
  - b. Swelling

Various forms of hole instability arise when the stress relief of overburden pressure occasioned by drilling exceeds the yield strength of the formation. A well-known example of this phenomenon is the plastic flow that occurs in geopressed shales. The water content and the plasticity of the shale are abnormally high relative to the overburden load, and the shale is extruded into the hole in plastic flow.

When the pressure of the drilling fluid is less than the pressure of the fluids within the pores of the rock being drilled, the pressure differential toward the hole tends to induce fragments of rock to fall into the hole. Such caving is more likely to occur when the rock is relatively impermeable. The strength of the rock is a factor in this process as well.

Tectonic forces result from stresses imposed on a given stratum by deformation of the crust of the earth. Such deformation is commonly described as folding and faulting, and is a normal result of the formation of mountains. Stresses thus created are relieved quickly in shale that is readily deformable, but tend to remain in rocks that are brittle. Even a small amount of water adsorption can cause sufficient stress to induce shales to flake off in fragments and slough into the hole.

#### Shale Classifications

Reference to a shale classification like the one given in Table I is helpful for a description of the effect of water absorption on shale stability. Because the number of combinations of physical and chemical properties of rocks called "shale" is so large, a classification of some kind is necessary for a logical and organized approach to predict the probability of occurrence. For purposes of illustration, a description follows of how shales of Class A through E behave upon wetting with fresh water. Obviously the behavior of the different classes of shale would be different in various salt solutions.

FIGURE 7  
WATER RETAINED UDER LOAD  
(FROM DARLEY)

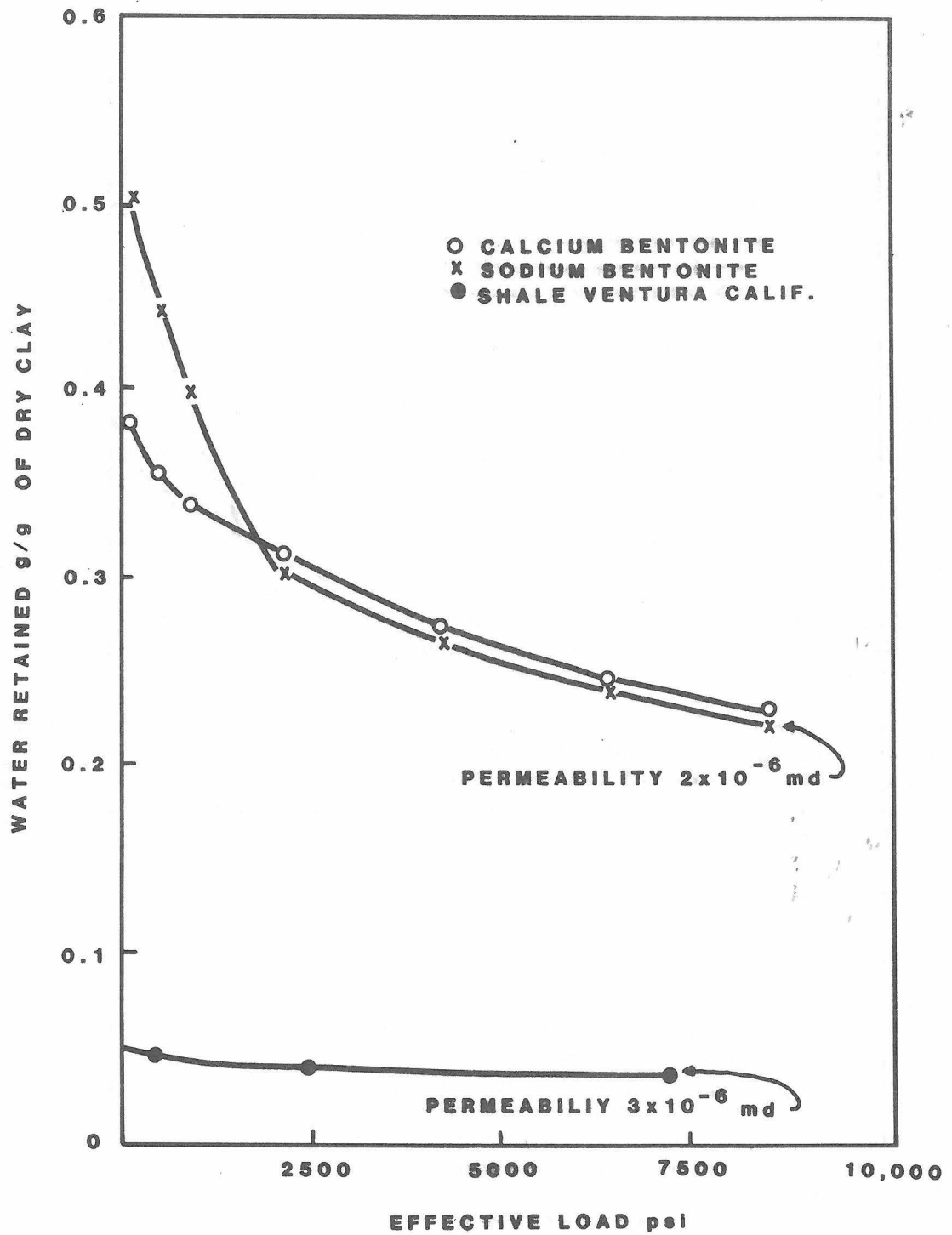


TABLE 1  
A GENERAL SHALE CLASSIFICATION

| <u>Class</u> | <u>Texture</u> | <u>Methylene<br/>blue<br/>capacity<br/>(me/100g)</u> | <u>Water<br/>Content</u> | <u>Wt%<br/>Water</u> | <u>Clay<br/>Content</u>                                 | <u>Wt%<br/>Clay</u> | <u>Density<br/>g/cc</u> |
|--------------|----------------|------------------------------------------------------|--------------------------|----------------------|---------------------------------------------------------|---------------------|-------------------------|
| A            | Soft           | 20-40                                                | Free and<br>bound        | 25-70                | Montmorillonite<br>and illite                           | 20-30               | 1.2-1.5                 |
| B            | Firm           | 10-20                                                | Bound                    | 15-25                | Illite and<br>mixed layer<br>montmorillonite-<br>illite | 20-30               | 1.5-2.2                 |
| C            | Hard           | 3-10                                                 | Bound                    | 5-15                 | Trace of<br>montmorillonite<br>high in illite           | 20-30               | 2.2-2.5                 |
| D            | Brittle        | 0-3                                                  | Bound                    | 2-5                  | Illite, kaolin<br>chlorite                              | 5-30                | 2.5-2.7                 |
| E            | Firm-hard      | 10-20                                                | Bound                    | 2-10                 | Illite and<br>mixed layer<br>montmorillonite-<br>illite | 20-30               | 2.3-2.7                 |

(From Mondshine 1969)

Class-A shale is characterized primarily by high-water content and relatively high expandable clay content. The word montmorillonite as used in Table I denotes expandable clays as identified by the methylene blue test. The word smectite is now a more widely accepted group name. Montmorillonite is a member of the smectite group. Shale of this quality is often found at shallow depth where the overburden load is still too small to have squeezed more water from the sediments during compaction, and the temperature too low to have induced diagenesis. The same shale may also be found at greater depth when permeable avenues for the escape of connate water did not exist, and where conditions were not right for montmorillonite to have been altered to illite (see Figure 6). When still more water is added to Class A shale, it would be expected that the compaction process would be to a degree reversed. In the higher water content range, this shale could also be squeezed into the hole from the pressure created by the weight of the overburden. The lower the mud weight, the more likely it would be for this phenomenon to occur.

Class-B shale would respond to adsorption of fresh water mainly by becoming more plastic or less firm. Water would penetrate slowly from the borehole into the shale body. Capillary adsorption of water into bedding planes would occur nominally if at all, because of the smectite clays in the shale. Abnormal pore pressure in shale of this description is possible. Aside from possible pressure effects, Class-B shale would usually remain rather stable after being penetrated.

Class-C shale would be more likely to slough into the hole than either Class A or B. This type of shale would be found in sediments similar to those that constituted Class-B shale, but at greater depth. Some softening would occur upon adsorption of fresh water. Very likely there would be sections where the shale would still be hard after water adsorption and some swelling, so that some fragments would disengage from the matrix and fall into the hole. The mechanism of fragmentation could be the result of either capillary adsorption along bedding planes, or simply penetration of water into the shale body away from the hole.

Class D shale may be found at both shallow and great depths, but is likely to be quite old geologically. Brittle shale subdivides into small particles when immersed in water, but swells and softens very little if at all. It is believed that cleavage takes place along old fracture planes that are held together by attractive forces that act over short distances only. Hydration when contacted by an aqueous drilling fluid causes separation at the old fracture planes.

Class E shales are likely to be found quite deep, and are usually abnormally pressured. Occurrence of this type of shale is sometimes thought to be anomalous, even though it is found quite often in sediments of tertiary age. This shale would have a strong tendency to slough upon adsorption of fresh water. In interbedded smectite-illite intervals, illite ledges may be broken off by the unequal degree of swelling of the two different shales.

## Shale Hydration

Water wetting of shale can and usually does result in borehole blockage. The instability usually results primarily from overburden pressure, pore pressure, or tectonic stress. This is true regardless of whether the clay in the shale is largely expandable or non-expandable, or whether the shale in place is brittle or plastic. Moreover, shale dispersion, hole closure or sloughing from shale swelling are all attributable to adsorption of water by shale.

The forces that cause shale to absorb water are attributable to the clay in the shale. It should also be emphasized at the outset that these forces through which clay adsorbs, imbibes, draws or sucks water into itself can be very great. By comparison the force with which mud filtrate may be pressed into the formation by the differential between the hydrostatic pressure of the mud column and the pore pressure of the formation is very small. For example, if a normally pressured stratum at 5000 or 10,000 feet on the Gulf Coast is drilled with 9.5 ppg mud, the pressure differential would be about 125 and 250 psi respectively. This figure represents the pressure with which filtrate from the mud is being pressed into the formation by the overbalance of hydrostatic pressure over pore pressure. The text following will illustrate that the water adsorption forces of shale are much greater.

Hydration of shale depends upon a number of factors such as the hydration energy of the interlayer cations on the clays present and the charge density on the surface of the clay crystals. A reasonable estimate of the shale hydration force can be made by considering the compaction forces involved in subsurface burial of a given shale stratum during geologic time. For well drilling purposes, the hydration force is calculated conveniently in this way. The effective compaction stress on a shale section at any given depth can be represented by the equation,  $s = S - P$ , where  $s$  is the intergranular or matrix stress (W.R. Mathews and J. Kelly, 1967),  $S$  is the overburden pressure (approximately 1 psi/ft), and  $P$  is the pressure on the fluid in the pores of the rock.

As a given layer of shale is buried deeper, progressively more water is squeezed out of the shale by the weight of the overburden. The force with which water is being expelled from the shale in the compaction process equals the intergranular or matrix stress. The adsorption (or suction) force of the clay acts in opposition to the water expulsion force of compaction. This compacting force is relieved on the borehole face when the shale is penetrated by the bit. Consequently, a hydration force equal to the degree of relief develops. Since the compaction force equals the matrix stress, then:

$$\text{SHALE HYDRATION FORCE}_{\text{psi}} = \text{OVERBURDEN}_{\text{psi}} - \text{PORE PRESSURE}_{\text{psi}}$$

For example, assuming again a normally pressured shale (9 lb/gal mud weight equivalent) at 10,000 ft on the Gulf Coast:

$$\text{OVERBURDEN}_{\text{psi}} = 1 \text{ psi/ft} = 10,000 \text{ psi}$$

$$\begin{aligned} \text{MATRIX STRESS}_{\text{psi}} &= \text{OVERBURDEN}_{\text{psi}} - \text{PORE PRESSURE}_{\text{psi}} \\ &= 10,000 \text{ psi} - (9 \times 0.052 \times 10,000) \text{ psi} \\ &= 5320 \text{ psi} \end{aligned}$$

The shale hydration force at 10,000 feet in normal pore pressure is therefore 5320 psi.

### Drilling Fluids

Artificial penetrations in the area of review or zone of endangering influence can provide potential conduits to USDWs if improperly plugged when abandoned, improperly cemented when constructed or a combination thereof. Artificial penetrations are usually man-made holes used for the exploration of oil and gas or other minerals and water. These holes are rarely empty and are fluid filled with native water, brine or drilling fluid. In the case of native waters or brine the fluids may have seeped into the well bore or been left there by the original driller. If the well was originally drilled with a cable tool rig or rotary drilling rig using compressed air, the fluid in the hole is probably native water or brine. However, the vast majority of artificial penetrations are made exploring for oil and gas. Therefore, it is logical to conclude that most well bores are mud filled since rotary drilling techniques using drilling fluid are predominately used when drilling oil and gas exploration and development wells. Upon completion of the drilling operation, if the well is not completed for production, the drill pipe is removed from the well bore and the drilling mud used to drill the well will remain in the well bore indefinitely. If the well is completed or casing is run and partially cemented across a portion of the well bore, drilling mud would have been displaced ahead of the cement from the annular space between the casing and open hole. If cement was not circulated to the surface, then the annular space above the cemented section will be filled with drilling mud.

A fluid filled well bore or annular space provides resistance to upwards fluid migration because of two opposing forces. The first would be the hydrostatic head or downward force caused by the weight of the fluid column. This can be described as psi/foot of depth by taking the weight of one cubic foot of water and dividing it into 144 square inches one-foot high. A cubic foot of water weighs approximately 62.3 pounds, dividing by 144 square inches, we find that a column of water one-foot high exerts a downward pressure of 0.433 psi. Therefore a column of water 1000 feet deep would provide a downward force of 433 psi. If fluid were migrating upward, it would have to have a driving force in excess of 433 psi. This example used fresh water having a density of 8.33 lbs/gal. The second opposing force that would act as a deterrent to fluid migration along a well bore would be present only if the fluid filling the well bore had gel strength. Most drilling fluids contain this characteristic.

One of the primary functions of the drilling mud is the removal of drilled cuttings from the well bore. The mud carries the cuttings from beneath the bit, transports them up the well bore/drill pipe annulus and releases them at the surface. Since normal drilling operations require that mud circulation be stopped periodically to add another joint of drill pipe, the mud must have a property which acts to suspend the drilled cuttings in the static mud column. This property is known as gel strength. Gel strength is time dependent and increases as the mud column remains quiescent. Most drilling fluids are thixotropic and develop a gel structure like "Jello" when allowed to stand quiescent but become fluid when disturbed.

To determine the combined effect of both hydrostatic head and gel strength acting as a deterrent to fluid migration along a mud filled well bore or annulus, we must first identify the forces acting on a well bore and/or annulus existing in a static state. Figure 8 represents a vertical force diagram of a static mud column in an abandoned well that contains no uncemented casing. Figure 9 represents the forces acting on the static mud column in the annulus between the casing and open hole above the cemented interval.

The equation for the force balance in Figure 8 takes the following form,

$$w + GS_w (2 \pi r_w h) = P_f (\pi r_w^2) - P_t (\pi r_w^2) \quad (18)$$

where

$$w = r_w^2 \rho h$$

and

- $w$  = weight of mud column
- $GS_w$  = gel strength of mud column acting on circumference area of well bore
- $P_t$  = pressure at top of well
- $P_f$  = pressure at formation being contained
- $r_w$  = radius of well bore
- $h$  = height of mud column in well bore
- $\rho$  = density of mud

Simplifying the force balance and adjusting for standard units, we obtain the following pressure equation,

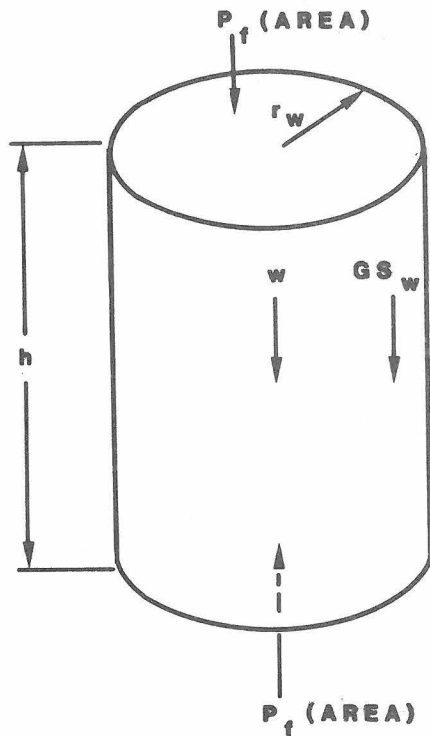
$$P_f = P_t + 0.052 \rho h + 3.33 \times 10^{-3} GS_h / D \quad (19)$$

where:

- $P_f$  = pressure at the contained formation in psi
- $P_t$  = pressure at the top of well
- $\rho$  = density of mud in lb/gal
- $h$  = height of mud column in feet
- $GS$  = gel strength in lb/100 ft<sup>2</sup>
- $D$  = diameter of well bore in inches

FIGURE 8

STATIC MUD COLUMN  
FORCE BALANCE DIAGRAM



$P_t$  (AREA) = PRESSURE AT THE TOP  
OF WELL =  $P_t \pi r_w^2$

$W$  = WEIGHT OF FLUID COLUMN  
 $\rho h \pi r_w^2$

$GS_w$  = GEL STRENGTH OF MUD ACTING  
ON CIRCUMFERENCE AREA OF WELL  
BORE =  $GS_w (2 \pi r_w h)$

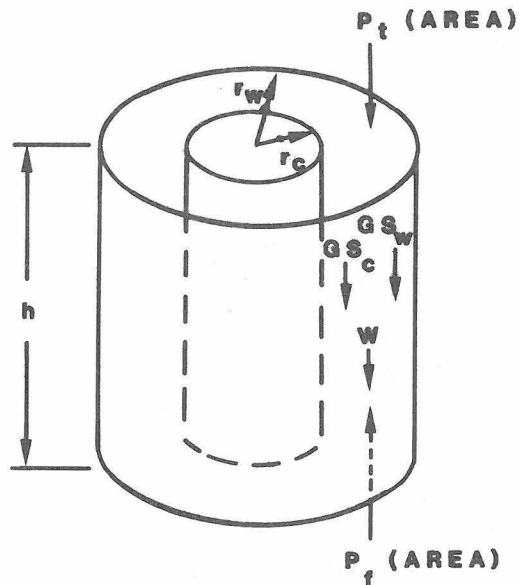
$P_f$  (AREA) PRESSURE AT THE  
FORMATION BEING CONTAINED  
 $P_f \pi r_w^2$

FORCES FROM MUD COLUMN SUM OF PRESSURE FORCES

$$w + GS_w (2 \pi r_w h) = P_f (\pi r_w^2) - P_t (\pi r_w^2)$$

**FIGURE 9**  
**ANNULUS STATIC MUD COLUMN**  
**FORCE BALANCE DIAGRAM**

**WELLBORE ANNULAR EFFECTS**



**FORCES FROM MUD COLUMN = SUM OF PRESSURE FORCE**

$$W + GS_c(2\pi r_c h) + GS_w(2\pi r_w h) = P_f \pi (r_w^2 - r_c^2) - P_t \pi (r_w^2 - r_c^2)$$

The force balance equation for Figure 2 takes the form

$$w + GS_C(2\pi r_C h) + GS_W(2\pi r_W h) = \quad (20)$$

$$P_f \pi (r_W^2 - r_C^2) - P_t \pi (r_W^2 - r_C^2)$$

where

$$w = \rho h (r_W^2 - r_C^2)$$

and

- w = weight of mud column in annulus
- GS = gel strength of mud acting on circumference area of both the well bore ( $GS_W$ ) and casing wall ( $GS_C$ ) and  $GS_W = GS_C$
- $P_t$  = pressure at top of well
- $P_f$  = pressure at formation being contained
- $r_W$  = radius of well bore
- $r_C$  = outside radius of casing
- h = height of mud column in annulus
- $\rho$  = density of mud

Simplifying the force balance and adjusting for standard units, we obtain the following pressure equation,

$$P_f = P_t + .052\rho h + \frac{3.33 \times 10^{-3} GS h}{D_W - D_C} \quad (21)$$

where:

- $P_f$  = pressure at the contained formation in psi
- $P_t$  = pressure at the top of the well
- $\rho$  = density of mud in lb/gal
- h = height mud column in feet
- GS = gel strength of mud in lb/100 ft<sup>2</sup>
- $D_W$  = diameter of well bore in inches
- $D_C$  = outside diameter of casing in inches

### Drilling Fluid Properties

It is generally recommended that the values required to calculate the flow resistance of a mud filled well bore or annular space be obtained from the well records. The physical configuration of the well can usually be obtained from many sources. These include but are not limited to state and federal permit records, the owner/operator files, commercial libraries, geological surveys and other public information sources. The density of the drilling fluid used to drill the well is normally recorded on the geophysical log heading as shown in Exhibit 1. The gel strength values may be more difficult to obtain. Mud properties are generally run while conditioning the mud to run casing and cement. These values are normally determined by the drilling fluid supplier or service company and are reported on standardized forms such as the one shown in Exhibit 2. These data are normally available from the owner/operator's well files or the service company. Also, it is frequently not necessary to find the

EXHIBIT 1

Schlumberger

BOREHOLE GEOMETRY LOG

|                                                      |                                  |                   |
|------------------------------------------------------|----------------------------------|-------------------|
| COUNTY<br>FIELD or<br>LOCATION<br>WELL<br>COMPANY    | COMPANY _____                    |                   |
|                                                      | WELL _____                       |                   |
|                                                      | FIELD _____                      |                   |
|                                                      | COUNTY _____                     | STATE _____       |
| LOCATION                                             | Other Services: _____            |                   |
|                                                      | Sec. _____ Twp. _____ Rge. _____ |                   |
| Permanent Datum: _____, Elev. _____                  |                                  | Elev.: K.B. _____ |
| Log Measured From _____, _____ Ft. Above Perm. Datum |                                  | D.F. _____        |
| Drilling Measured From _____                         |                                  | G.L. _____        |
| Date _____                                           |                                  |                   |
| Run No. _____                                        |                                  |                   |
| Depth—Driller _____                                  |                                  |                   |
| Depth—Logger _____                                   |                                  |                   |
| Btm. Log Interval _____                              |                                  |                   |
| Top Log Interval _____                               |                                  |                   |
| Casing—Driller @ @ @ @                               |                                  |                   |
| Casing—Logger _____                                  |                                  |                   |
| Bit Size _____                                       |                                  |                   |
| Type Fluid in Hole: _____                            |                                  |                   |
| Fluid Level _____                                    |                                  |                   |
| Dens.                                                | Visc.                            |                   |
| pH                                                   | Fluid Loss                       | ml ml ml ml       |
| Source of Sample _____                               |                                  |                   |
| R <sub>in</sub> @ Meas. Temp.                        | @ °F                             | @ °F @ °F @ °F    |
| R <sub>mid</sub> @ Meas. Temp.                       | @ °F                             | @ °F @ °F @ °F    |
| R <sub>out</sub> @ Meas. Temp.                       | @ °F                             | @ °F @ °F @ °F    |
| Source: R <sub>mid</sub> R <sub>out</sub>            |                                  |                   |
| R <sub>in</sub> @ BHT                                | @ °F                             | @ °F @ °F @ °F    |
| Time Since Circ. _____                               |                                  |                   |
| Max. Rec. Temp. °F °F °F °F                          |                                  |                   |
| Equip. Location _____                                |                                  |                   |
| Recorded By _____                                    |                                  |                   |
| Witnessed By _____                                   |                                  |                   |

## EXHIBIT 2

## WELL HISTORY

# Magcobar

☐ DRILLING FLUID SERVICES ☐

[illegible]

well records of each well since wells drilled adjacent to each other frequently use the same or similar mud systems. Historical records are also a good source of obtaining conservative values for gel strengths of specific types of drilling fluid systems.

Since the gel strength of different types of mud systems varies, it is difficult to determine the exact gel strength of the mud in a particular well bore. A review of the gel strength characteristics of various types of muds was made to evaluate the factors that effect the gel strength structure. The aim of this review was to provide sufficient information to determine the minimum gel strength structure that could be anticipated for any combination of formation, well bore and mud type. This value can then be used if insufficient data is available for a specific well bore.

Thixotropy is the property, exhibited by certain gels, of liquifying when stirred or shaken and then returning to their gelled state when allowed to stand quiescent. This property in drilling fluids is the result of various clay minerals being used as additives in drilling fluids. Generally, clay particles fall into the colloidal particle range. Colloidal systems used in drilling fluids include solids dispersed in liquids and liquid droplets dispersed in other liquids. These highly active colloidal particles comprise a small percentage of the total solids in drilling muds but act to form the dispersed gel forming phase of the mud that provides the desired viscosity, thixotropy and wall cake properties.

Clay particles and organic colloids comprise the two classes of colloids used when mixing drilling fluids. The common organic colloids include starch, carboxycelluloses and polyacrylamine derivatives.

Barker (1981) reported that, "The clay colloids utilized in common drilling fluids are characterized by a crystalline structure which influences the ability of the clay to retain water." Clays used in fresh water muds consist of hydrated aluminosilicates comprised of alternate plates of silica and aluminum to form layers of each mineral. The plate-like crystals have two distinct surfaces: a flat face surface and an edge surface. Slight surface polarities induce weak electrostatic forces along the faces and edges of the mineral plates. Garison (1939) noted that these electrostatic forces attract planer water to the colloidal particles forcing the clays to swell when wet and shrink when dry. The attraction of planer water to the faces of the plates is greater than the attraction of the sheets for each other therefore the structure tends to swell due to the absorption of the planer water from the drilling fluid. The bentonite clays demonstrate a strong ability to attract planer water as a result they experience extreme swelling. When in contact with fresh water, the face to face attraction of water by the mineral layers will continue until the swelling reduces the attraction of the plates to the point where they separate. This separation results in a higher number of particles and is referred to as dispersion. The dispersion causes the colloidal suspension to thicken. The degree of thickening depends on the electrolytic content, salt concentration of the water, time, temperature, pressure, pH, the exchangeable cations on the clay, and the clay concentration.

## Gel Strength, The Measure of Thixotropy

Thixotropy is essentially a surface phenomenon which is characterized by gel strength measurements. The gel strength indicates the attractive forces between particles under static conditions. The strength of the gel structure which forms under static conditions is a function of the amount and type of clays in suspension, time, temperature, pressure, Ph, and the chemical treating agents used in the mud. Those factors which promote, the edge-to-edge and face-to-edge association of the clay particles defined as flocculation increase the gelling tendency of the mud and those factors which prevent the association decrease the gelling tendency.

Due to their size, colloidal particles remain indefinitely in suspension. When suspended in pure water the clay particles will not flocculate. When flocculation occurs the particles form clumps or flocs. These loosely associated flocs contain large volumes of water. If the clay concentration in the mud is sufficiently high, flocculation will cause formation of a continuous gel structure instead of individual flocs.

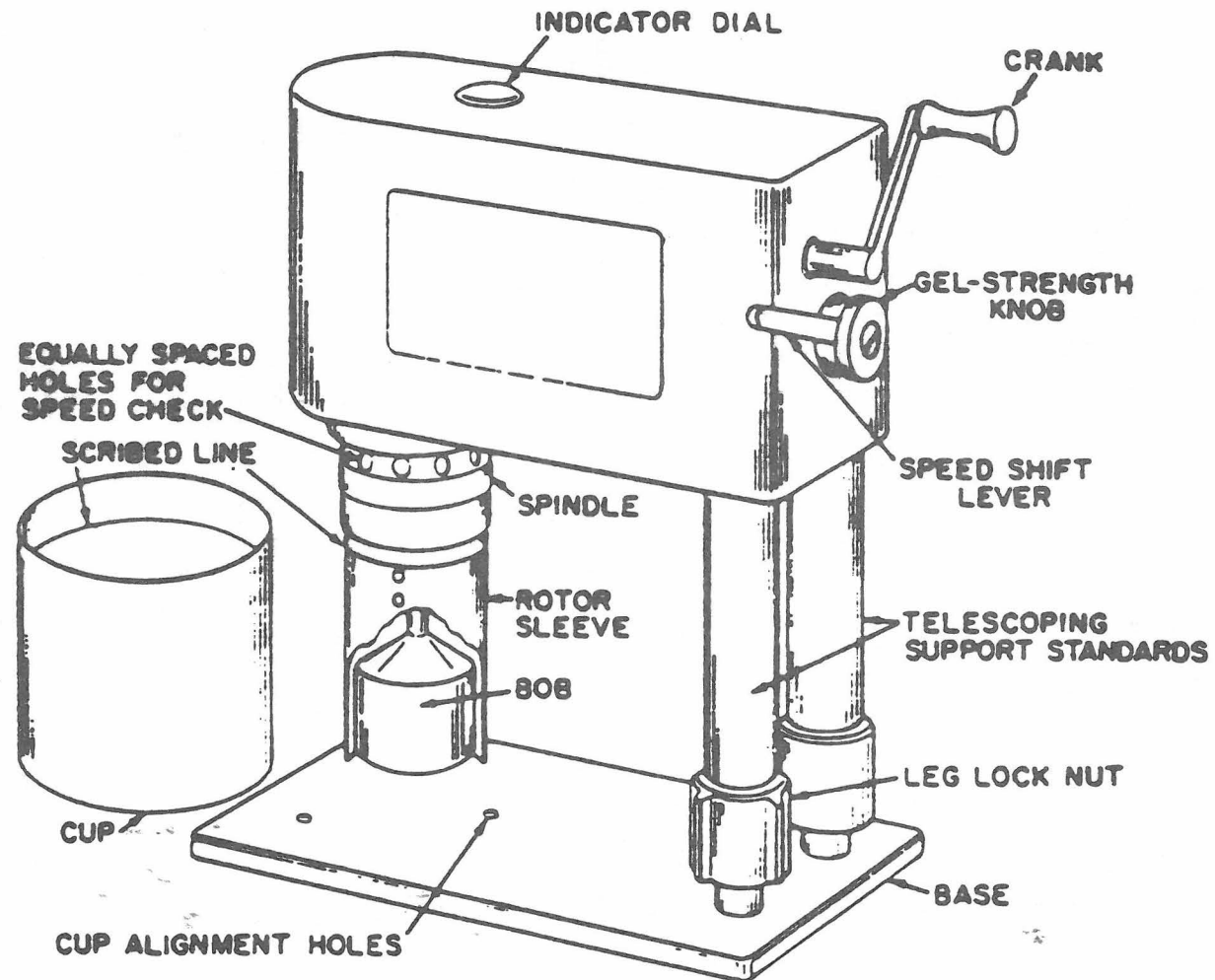
The gel structure commonly observed in aqueous drilling fluids results from salt contamination. Soluble salts are usually present in sufficient quantities to cause at least a mild flocculation. The time required for the gel to attain an ultimate strength depends on the critical concentration of electrolyte required to initiate flocculation, the thinners present, and the concentration of the clay and of the salt present. During drilling the presence of salts and clay particles varies with each formation being drilled, therefore the drilling fluid is monitored and adjustments are made in order to maintain the desired gel strength.

## Gel Strength of the Static Mud Column

Gel strength is measured by a multispeed direct indicating viscometer (See Exhibit 3) by slowly turning the driving shaft by hand and observing the maximum deflections before the gel structure breaks. The gel strength is normally measured after quiescent periods of 10 seconds (initial gel strength) and 10 minutes. The measurements are taken at surface conditions of standard temperature and pressure. To determine the gel strength of the static mud column in an abandoned well it is necessary to determine the gel strength of the mud under the influence of borehole conditions. The initial and 10 minute gel strengths bare to direct relation to the ultimate gel strength of the mud at borehole conditions. To determine the ultimate gel strength of a mud it is necessary to discuss the factors which act to influence the initial gel strength at borehole conditions.

Once the drilling operation is completed and the well is abandoned the mud is subjected to conditions vastly different from those encountered at the surface. In the range of formation depths utilized for disposal of industrial wastes the temperature would be expected to range from 80 to 300°F, the pressure from 1500 to 5000 psi and time from days to several years. Several studies have been conducted to determine the impact of time, temperature and pressure on the gel strength of muds at borehole

EXHIBIT 3  
HAND VISCOMETER



conditions. The information obtained from this research should provide a means of determining a reasonable minimum gel strength value for the abandoned wells which exist in the range of formations described above.

It is observed that common use water base muds develop high gel strengths after prolonged periods of quiescence. The relationship between gel strength and time varies widely from mud to mud, depending on the composition, degree of flocculation, temperature, pH, solids, and pressure. Figure 10 (G.D. Gray, H.C. Darley and W.F. Rogers, 1980) indicates the increase in gel strength with time for various mud types and reveals that there is no well established means of predicting long term gel strengths with time. It is noted in all cases that the gel strength is observed to increase.

Garrison (1939) studied the gel strength in relation to time and rate of reaction for California bentonites. He observed that both the speed and the final strength increased with the bentonite percentages. The gelling was found to follow the equation:

$$S = \frac{S'kt}{1+kt} \quad (22)$$

where S is the gel strength at any time t, S' is the ultimate gel strength, and k is the gel rate constant. Figure 11 indicates that the gel strength forms more rapidly at first then gradually approaches an ultimate value as time elapsed. Equation 22 may be rewritten as:

$$\frac{t}{S} = \frac{t}{S'} + \frac{1}{S'k} \quad (23)$$

which indicates that a plot of t/S verses t should be a straight line. Figure 11 represents the graph of t/S versus t, and indicates the slope of the line is k and the y-intercept is 1/S'k. This approach provides a means to evaluate the ultimate gel strength for each bentonite concentration. Table 2 represents the ultimate gel strengths and rate constants for the five samples shown in Figures 11 and 12. Garrison also made measurements on similar suspensions at higher pH and determined that the ultimate strengths of the bentonite gels increased with each suspension as the pH increases. Table 3 reflects the pH - ultimate gel strength relationship observed.

Garrison also noted that the treating of muds with thinners had the effect of decreasing the rate of gelling but not the ultimate gel strength. Thus it can be concluded that the reduced initial and 10 minute gel strength will not be any less than that recorded for an untreated sample of the same mud. In fact, the ultimate gel strength may even increase as indicated in Table 2.

Garrison's work does not indicate that all muds comply with Equation 22, but it does point out that the initial and 10 minute gel strengths do not provide a reliable means of predicting the ultimate gel strength. Weintritt and Hughes (1965) conducted progressive gel strength tests on

FIGURE 10

INCREASE IN GEL STRENGTH OF  
VARIOUS MUD TYPES WITH TIME  
(FROM GRAY, DARLEY, AND ROGERS)

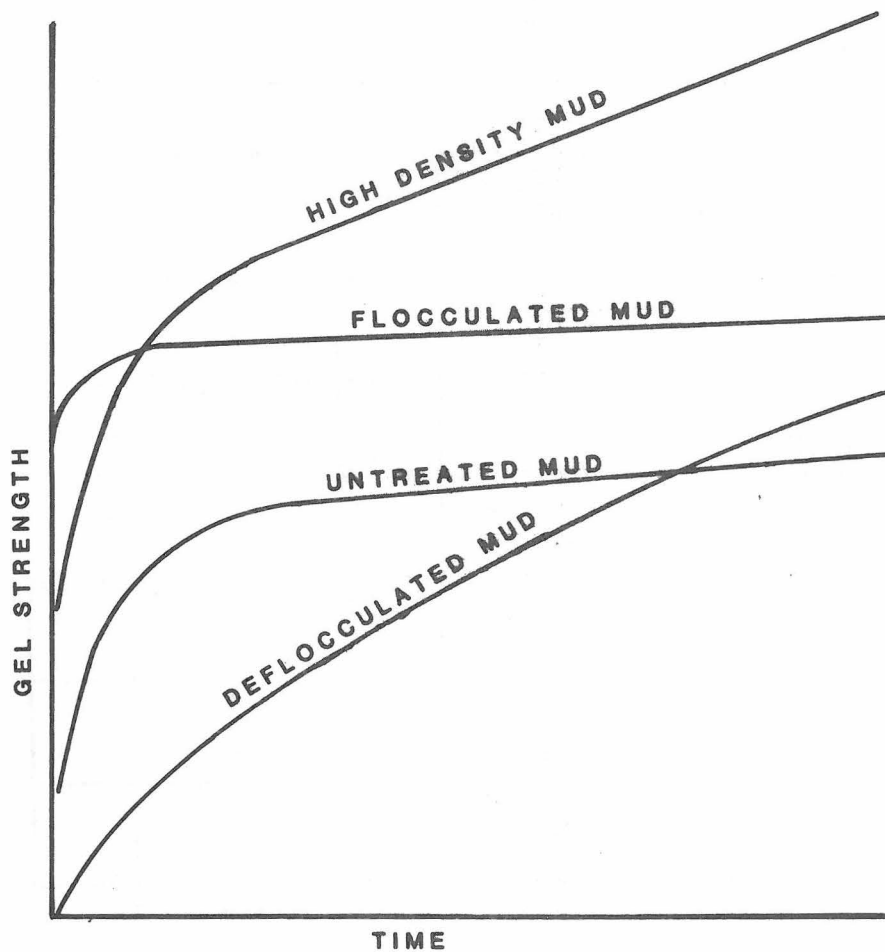


FIGURE 11  
GEL STRENGTH IN RELATION TO TIME  
AND RATE OF REACTION  
(FROM GARRISON 1939)

SEE TABLE 2

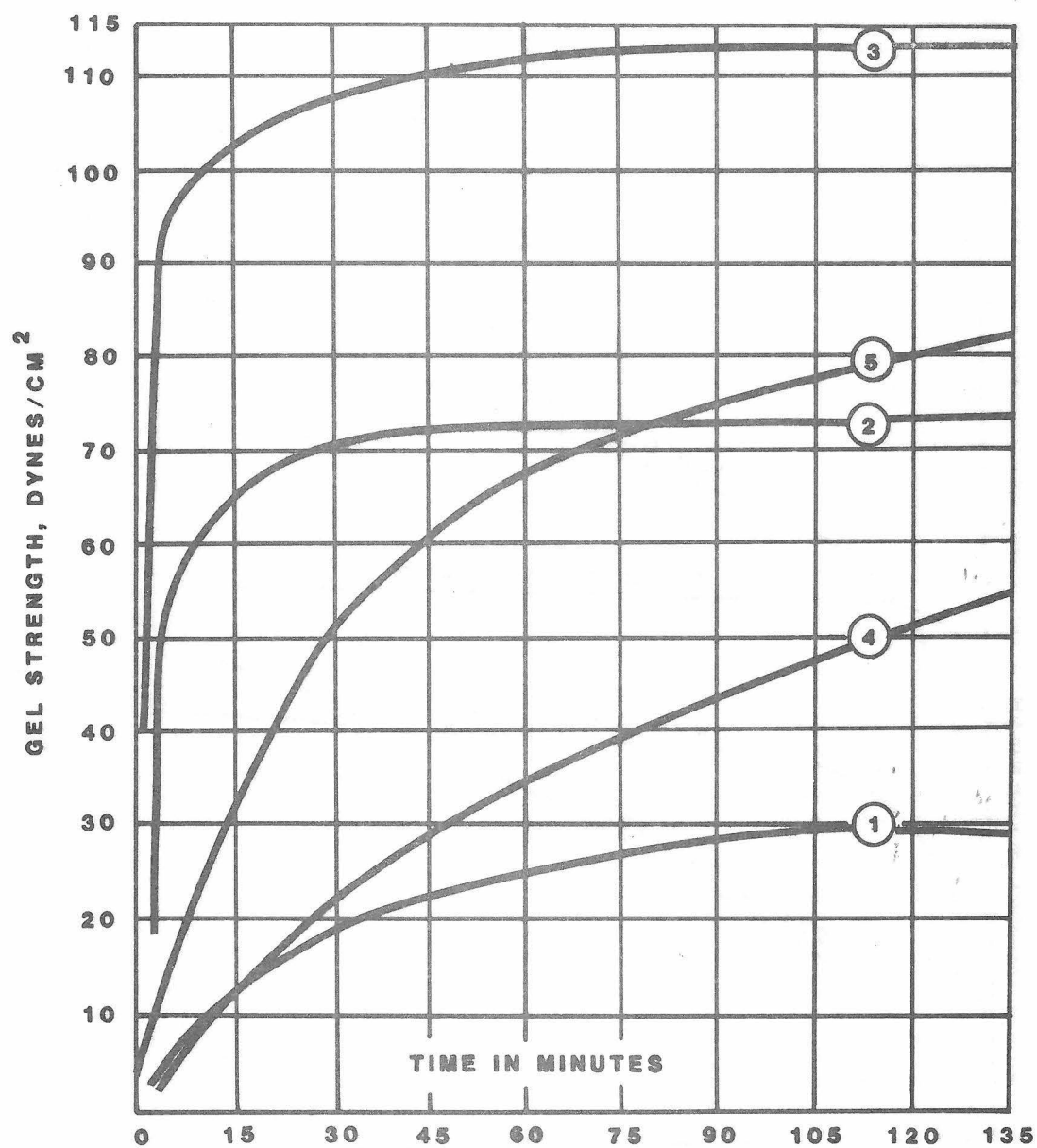


FIGURE 12  
 GEL STRENGTH AND RATE CONSTANTS  
 (FROM GARRISON 1939)  
 SEE TABLE 2

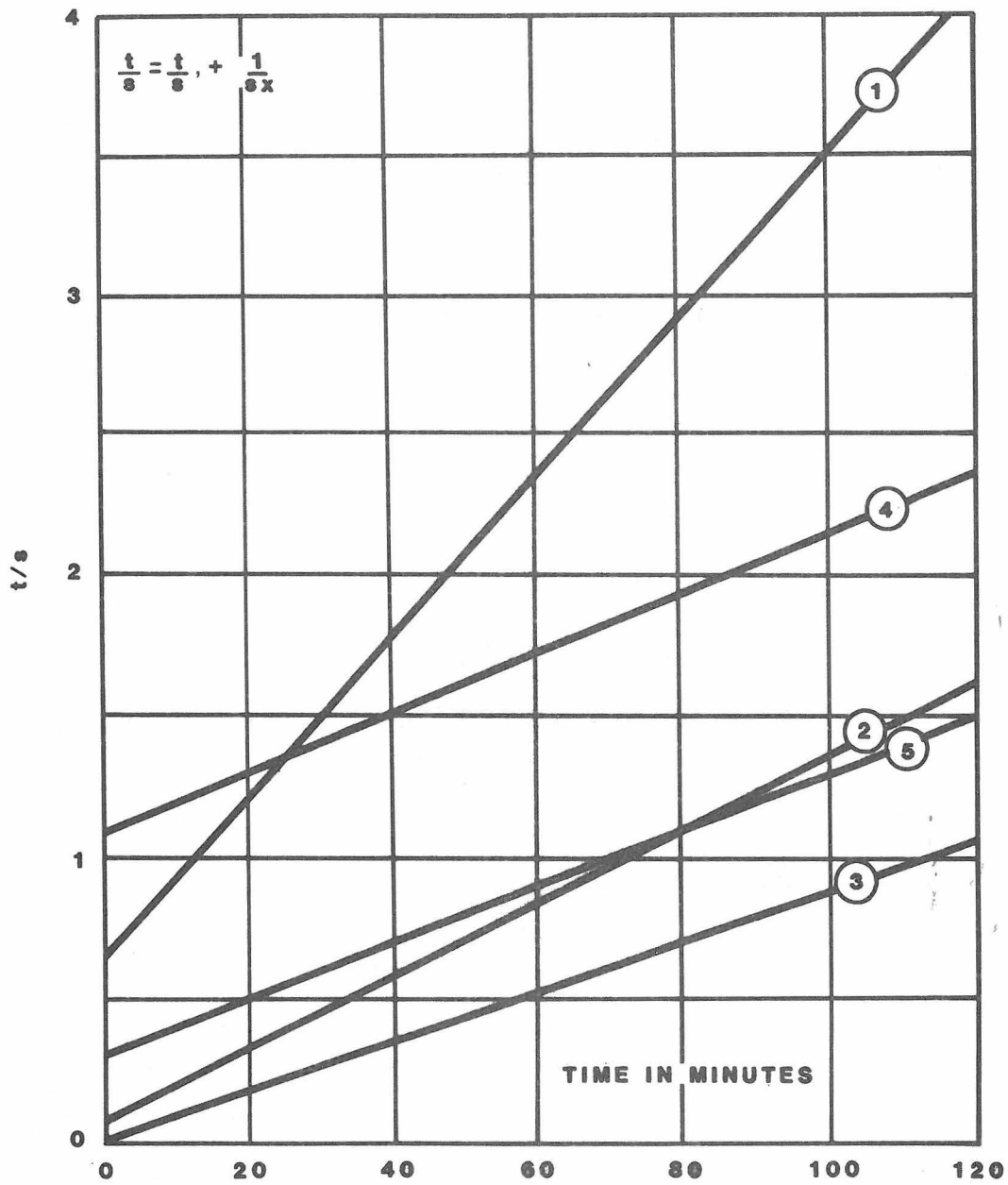


TABLE 2

GEL RATE CONSTANTS CALCULATED FROM FIGURES 11 AND 12

| Bentonite<br>Per Cent |          | Additives        | Gel Strength<br>(Ultimate) | Rate Constant |
|-----------------------|----------|------------------|----------------------------|---------------|
|                       | Sample # |                  |                            |               |
| 4.5                   | 1        | -----            | 34.4                       | 0.047         |
| 5.5                   | 2        | -----            | 74.4                       | 0.75          |
| 6.5                   | 3        | -----            | 114.                       | 0.79          |
| 5.5                   | 4        | 0.1% Na Tannate  | 104.                       | 0.0089        |
| 5.5                   | 5        | Sodium Hydroxide | 99.7                       | 0.033         |

(From Gray, Darley and Rogers)

TABLE 3

CONSTANTS IN GELLING EQUATIONS OF BENTONITE SUSPENSIONS

| Bentonite<br>Per Cent | Gel Strength<br>and Rate<br>Constant | pH+<br>9.2 | pH+<br>9.3-9.5 | pH+<br>9.9-10 | pH+<br>10.8-11 |
|-----------------------|--------------------------------------|------------|----------------|---------------|----------------|
| 4.5                   | S                                    | 34.4       | 40.1           | 48.5          | 69.6           |
| 4.5                   | k                                    | 0.047      | 0.071          | 0.076         | 0.063          |
| 5.5                   | S                                    | 74.4       | 32.2           | 129.9         | 152.7          |
| 5.5                   | k                                    | 0.75       | 0.22           | 0.13          | 0.18           |
| 6.5                   | S                                    | 114.       | 141.           | 250.          | 268.           |
| 6.5                   | k                                    | 0.79       | 0.30           | 0.10          | 0.25           |

(From Garrison 1939)

ferrochrome lignosulfonate muds for periods up to 16 hours and obtained the results presented in Table 4. They noted that although Mud E and Mud F had similar properties, Mud F developed only a moderate gel strength while that of Mud E was much greater. Once again it is observed that the initial gel strength and 10 minute gel strength measurements are not always indicative of gel strength development which is observed at elevated temperatures and extended time. The three muds designated in Table 4 were obtained from wells within the same field just prior to cementing operations.

Annis (1976) noted that when a bentonite mud is quiescent, the gelling process depends on both temperature and time. Annis compared the effect of temperature on the initial and 30 minute gel strength of an 18 ppb bentonite suspension. Figure 13 indicates that the 30 minute gel strength of the 18 ppb suspension is at any temperature approximately six times the initial gel strength. The dependence of gel strength on time at different temperatures, as noted by Annis, is shown in Figure 14. Based on these and other tests of up to 18 hours Annis concluded that there is a strong indication that gel strength increases indefinitely with time.

### Conclusion

In review, the above works indicate that the ultimate gel strength of water base muds is considerably higher than the values recorded for the initial and 10 minute gel strength. Although there is no direct relationship between gel strength and time, it is possible, based on available information, to conclude that the ultimate gel strength of a mud will be several times larger than the initial or 10 minute gel strength of the mud. In reference to the work by Garrison (1939), it is possible to consider the ultimate gel strength of a treated mud to be equivalent to that of a similar mud that was not treated, since the effect of the thinner is to decrease the rate of gelling and not the ultimate gel strength obtained.

In addition to time, temperature can have a major effect on the gel strength of water based drilling fluids. Srini-Vasan (1957) studied the effects of temperature on the gel strength of several water based drilling muds. Table 5 lists the muds which were tested and Figures 15 and 16 indicate the temperature versus gel strength relationships obtained. In most of the cases investigated by Srini-Vasan it was noted that the gel strength leveled off after 160°F. The emulsion and lime treated muds showed no change in gel strength with increase of temperature. It was found that each mud had its own characteristic curve and no quantitative interpretation was possible. The work of Weintritt and Hughes (1965) as noted in Table 4, indicates that emulsion Mud G experienced no change in gel strength in going from 75 to 180°F over a wide range of times. It is noted that although the gel strength did not vary with temperature, it went from an initial gel strength of 0 to a gel strength of 25 after 16 hours.

The equipment utilized by Srini-Vasan restricted his investigation to temperatures up to 220°F.

TABLE 4

COMPARISON OF MUD PROPERTIES WITH PROGRESSIVE GEL-STRENGTH TESTS  
GYP-FERROCHROME LIGNOSULFONATE EMULSION MUDS

|                             | SAMPLE |       |              |              |
|-----------------------------|--------|-------|--------------|--------------|
|                             | Mud E  | Mud F | Mud G        |              |
|                             |        |       | No Treatment | 3 lb/bbl PCL |
| Weight, unstirred, lb/gal   | 11.0   | 10.7  | 10.6         |              |
| Weight, stirred, lb/gal     | 11.0   | 10.3  | 10.7         |              |
| Plastic Viscosity, cp       | 14     | 23    | 16           | 15           |
| Yield Point, lb/100 sq ft   | 3      | 6     | 2            | 1            |
| 10-sec gel, lb/100 sq ft    | 1      | 2     | 1            | 0            |
| 10-min gel, lb/100 sq ft    | 8      | 8     | 7            | 3            |
| API filtrate, sl            | 6.2    | 3.3   | 5.2          | 2.9          |
| pH                          | 10.9   | 10.6  | 10.5         | 10.4         |
| Composition: water % by vol | 76     | 63    | 75           |              |
| Oil, % by vol               | 5      | 11    | 9            |              |
| Solids, % by vol            | 19     | 16    | 16           |              |
| Solids, % by wt             | 39     | 36    | 37           |              |
| Solids, SG                  | 2.7    | 2.9   | 3.0          |              |
| Filtrate Ion Analysis:      |        |       |              |              |
| Chlorides ppm               | 3500   | 400   | 3000         |              |
| Sulfate, epm                | 250    | 300   | 130          |              |
| Carbonate, epm              | 24     | 28    | 12           |              |
| Bicarbonate, epm            | 12     | 160   | 12           |              |
| Calcium, epm                | 44     | 52    | 44           |              |

| Progressive Gel Strengths |  | Temperature (°F) |      |      |      |     |      |      |      |
|---------------------------|--|------------------|------|------|------|-----|------|------|------|
| lb/100 sq ft              |  | 75°              |      | 180° |      | 75° |      | 180° |      |
| Time                      |  | 75°              | 180° | 75°  | 180° | 75° | 180° | 75°  | 180° |
| 0 minutes                 |  | 1                | 1    | 2    | 2    | 1   | 1    | 0    | 0    |
| 3 minutes                 |  | 2                | 3    | 2    | 5    | 3   | 8    | 1    | 1    |
| 10 minutes                |  | 8                | 18   | 8    | 12   | 7   | 26   | 3    | 3    |
| 30 minutes                |  | 15               | 40   | 11   | 18   | 17  | 58   | 5    | 5    |
| 60 minutes                |  | 27               | 90   | 18   | 16   | 29  | 91   | 6    | 6    |
| 2 hours                   |  | 31               | 145  | 22   | 22   | 29  | 104  | 7    | 7    |
| 4 hours                   |  | 37               | 190  | 29   | 42   | 46  | 172  | 10   | 10   |
| 8 hours                   |  | 46               | 190  | 33   | 42   |     |      |      |      |
| 16 hours                  |  | 80               | 320  | 40   | 57   | 95  | 320  | 25   | 25   |

(From Weintritt and Hughes 1965)

**FIGURE 13**  
**EFFECT OF TEMPERATURE ON INITIAL**  
**AND 30-MINUTE GEL STRENGTH**  
**(FROM ANNIS 1976)**

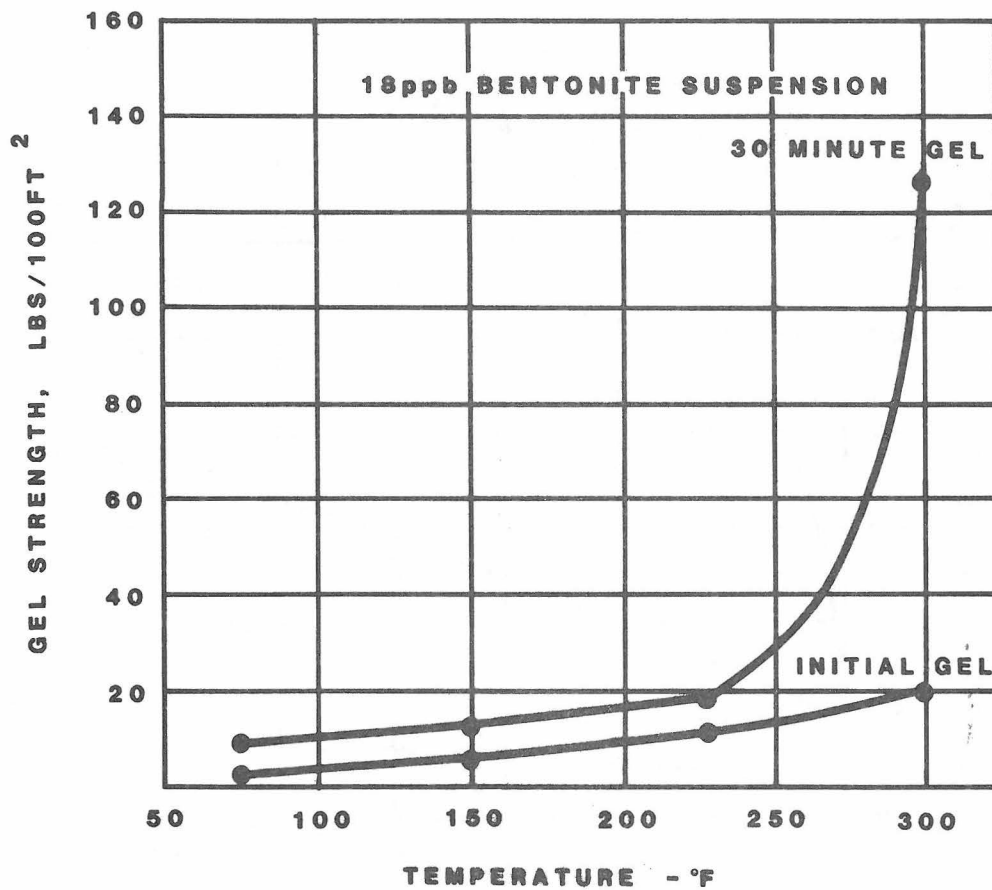


**FIGURE 14**  
**EFFECTS OF TIME AND TEMPERATURE**  
**ON GEL STRENGTH**  
**(FROM ANNIS 1976)**

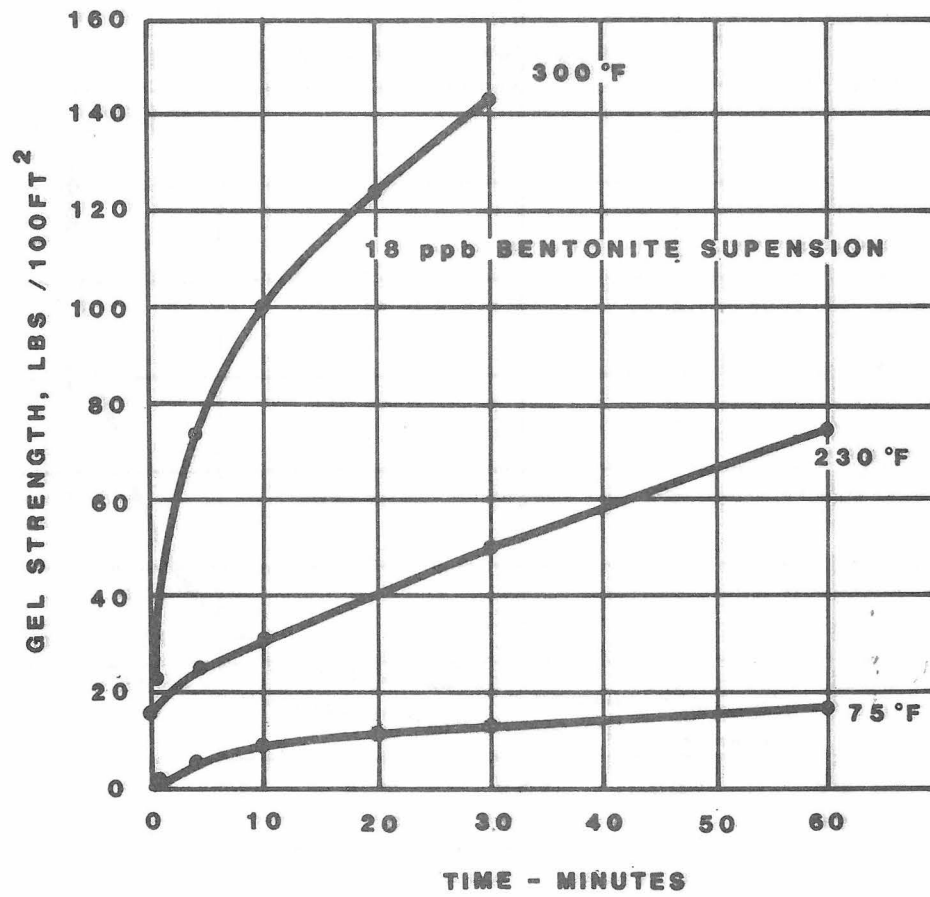


TABLE 5

## COMPOSITION OF THE MUD SAMPLES TESTED FOR GEL STRENGTH

| <u>SAMPLE NUMBER</u> | <u>COMPOSITION OF THE MUD**</u>                                                             |
|----------------------|---------------------------------------------------------------------------------------------|
| 33                   | 2 per cent bentonite mud                                                                    |
| 34                   | 3 per cent bentonite mud                                                                    |
| 35                   | 4 per cent bentonite mud                                                                    |
| 39                   | 10 lb/gal, 4 per cent bentonite, barite mud                                                 |
| 43                   | 10 lb/gal, 10 per cent (by volume) Diesel oil,<br>4 percent bentonite, barite, emulsion mud |
| 47                   | 10 lb/gal, 4 per cent bentonite, barite, surfactant<br>(DMS) mud                            |
| 49                   | 10 lb/gal, low lime (1 lb/bbl) treated, 4 per cent<br>bentonite, barite mud                 |

\*\*All muds referred to are water base muds.

All per cent quantities mentioned denote weight per cents, unless otherwise designated.

(From Srini-Vasan)

TABLE 6

GEL STRENGTH OF A 4 PERCENT SUSPENSION OF PURE SODIUM MONTMORILLONITE TO WHICH AN EXCESS OF 50 MEQ/LITER OF NaOH HAS BEEN ADDED, MEASURED AT VARIOUS TEMPERATURES AND PRESSURES

| <u>t(°F)</u> | <u>P(psi)</u> | <u>Gel Strength (lb/100 sq ft)</u> |               |               |
|--------------|---------------|------------------------------------|---------------|---------------|
|              |               | <u>1 min</u>                       | <u>10 min</u> | <u>30 min</u> |
| 78           | 300           | 2.2                                | --            | 35.0          |
|              | 8000          | 2.2                                | --            | 7.0           |
| 212          | 300           | 18.0                               | 26.0          | 40.0          |
|              | 8000          | 9.0                                | 9.0           | 15.0          |
| 302          | 300           | 240.0                              | 290.0         | 265.0         |
|              | 8000          | 88.0                               | 100.0         | 100.0         |

(From Hiller 1963)

**FIGURE 15**  
**GEL STRENGTH VERSUS TEMPERATURE FOR**  
**BENTONITE - WATER MUDS (FROM SRINI-VASAN 1957)**

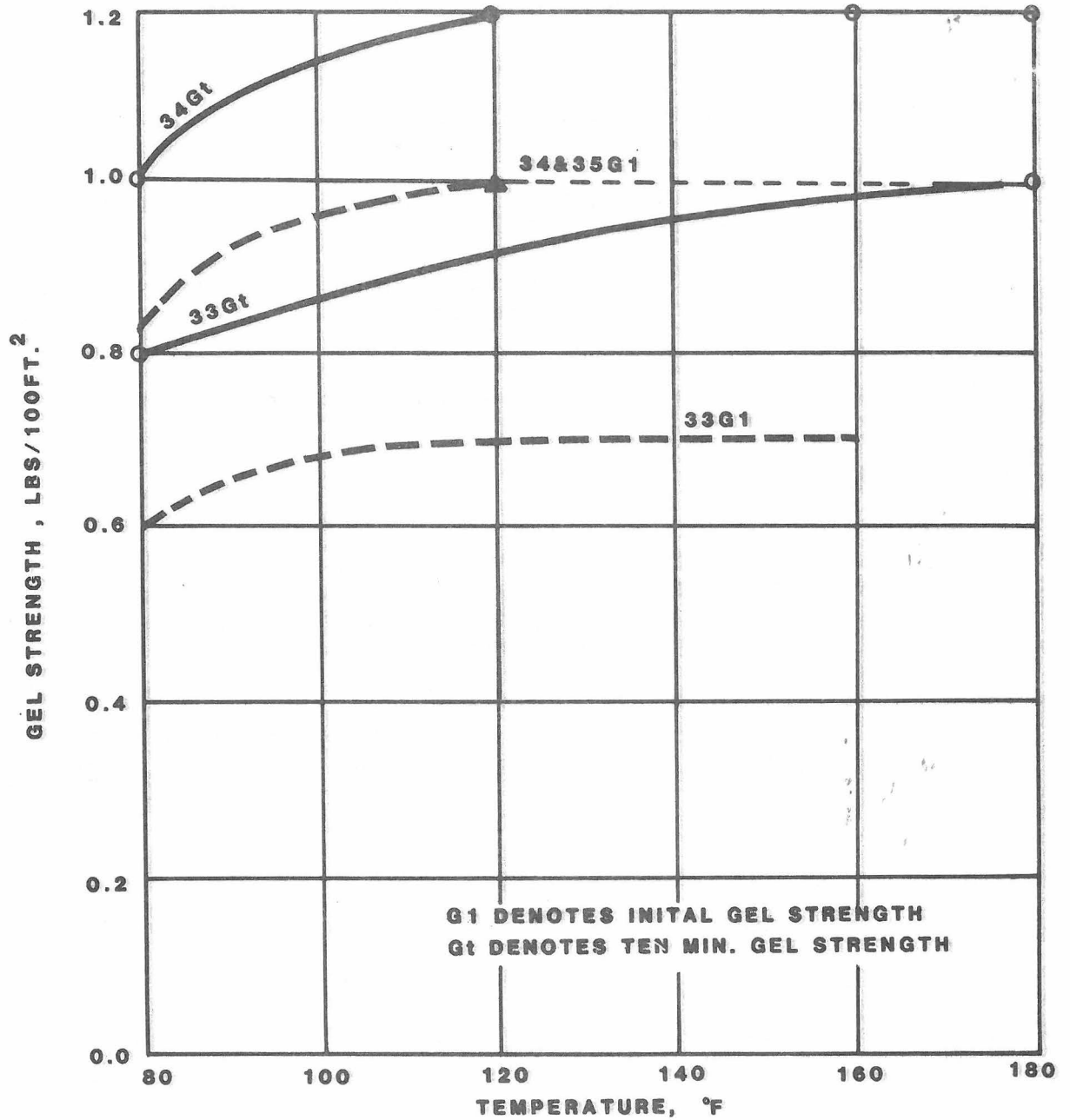
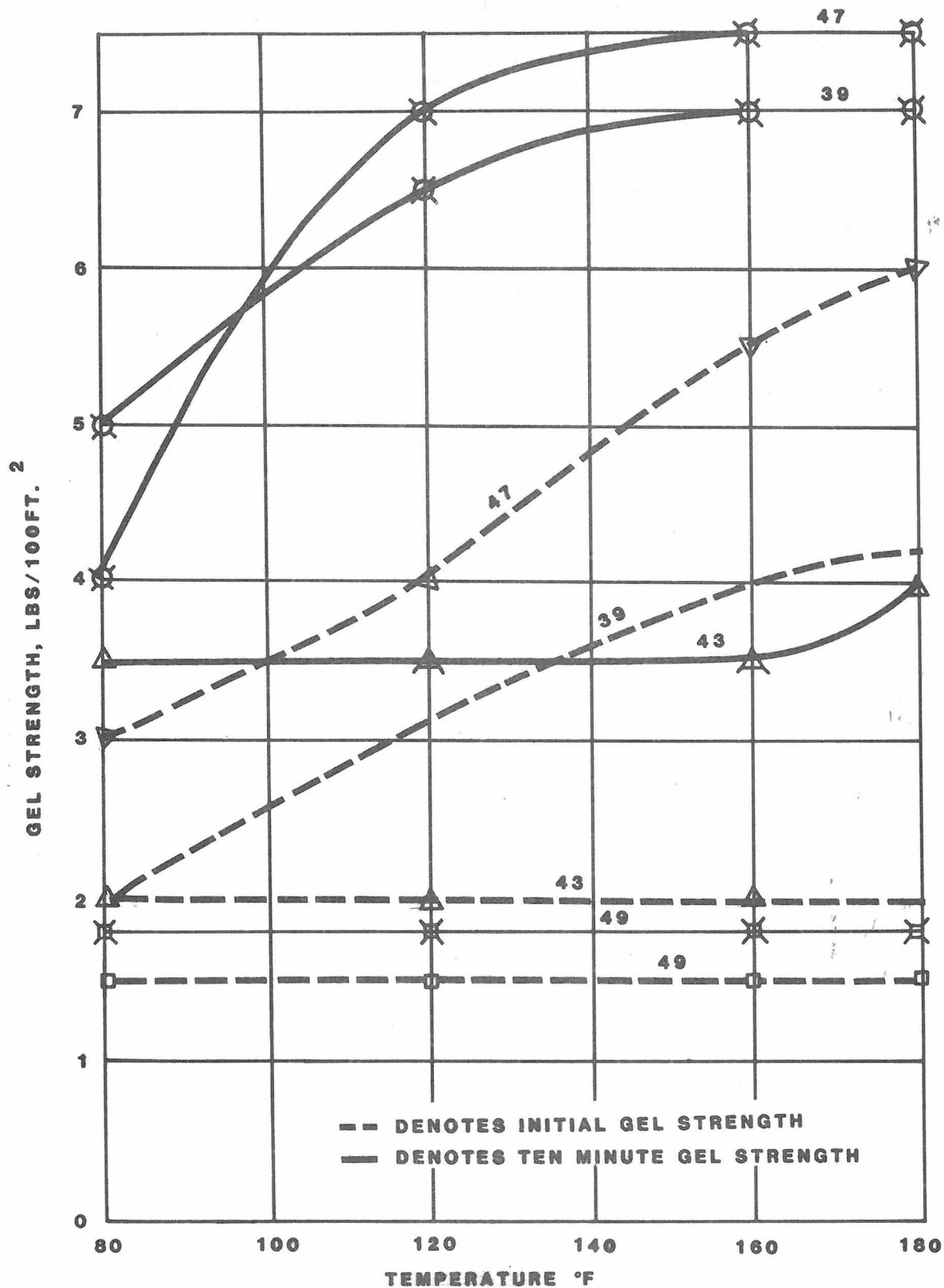


**FIGURE 16**  
**GEL STRENGTH VERSUS TEMPERATURE FOR**  
**DIFFERENT MUDS (FROM SRINI-VASAN 1957)**



Annis (1976) was capable of investigating the gel strength up to temperatures of 350°F. Srinivasan observed that the gel strengths leveled off after 160°F but Annis noted that at higher temperatures a rapid increase in the gel strength was noted. Figure 17 reflects this observation. Thus increased temperature, like increased bentonite concentration promotes flocculation. The temperature at which a rapid increase in gel strength occurs, represents the onset of flocculation. Therefore it is possible to expect the gel strength to increase significantly at some elevated temperature.

Annis studied the gel strength properties of about 40 water base field muds at temperatures ranging to 300°F. The muds covered a wide range of densities and mud types, although the majority were lignosulfonate muds. To draw conclusions on the effects of high temperature on gel strength, the gel strength properties were averaged and are presented in Figure 18.

Hiller (1963) noted that some clay suspensions display a decrease in gel strength with increased pressure, especially at high temperatures. It was noted that the gel strength was reduced to 1/4 of its original value for a pressure increase from 300 to 8000 psi at a temperature of 302°F. This reduction in the gel strength resulting from increased pressure is presented in Table 6.

Although no direct means exists to determine the ultimate gel strength of a drilling mud at borehole conditions, it is possible to safely say that the gel strength developed in the borehole is considerably greater than that indicated by the initial and 10 minute gel strengths recorded for a given mud. The effects of time, temperature and pressure on the gel strength of the static mud column have been discussed above. In the range of pressures and temperatures normally encountered in disposal formations, pressure should exert a negligible effect on the gel strength. Flocculation at high temperature should not occur except in the deepest of disposal formations. Certain muds do not display a temperature dependence, but the effect of time is ever present.

The research discussed above investigated muds with 0 initial gel strength to ultimate gel strengths of 100's lbs/100SF. In an attempt to select a minimum ultimate gel strength that could be expected for the worst of mud and borehole conditions, a value of 20 lbs/100 ft<sup>2</sup> should be utilized for the ultimate gel strength in all gel strength pressure calculations where actual numbers are not available. This value will provide a considerable safety factor in most cases.

The 20 lb/100 ft<sup>2</sup> ultimate gel strength was arbitrarily selected to insure that a sufficient safety factor is built into the proposed procedure. The selection is the result of individual judgment prejudiced by the above discussion."

**FIGURE 17**  
**EFFECTS OF TEMPERATURE AND BENTONITE**  
**CONCENTRATION ON 30 MINUTE GEL STRENGTH**  
**(FROM ANNIS 1976)**

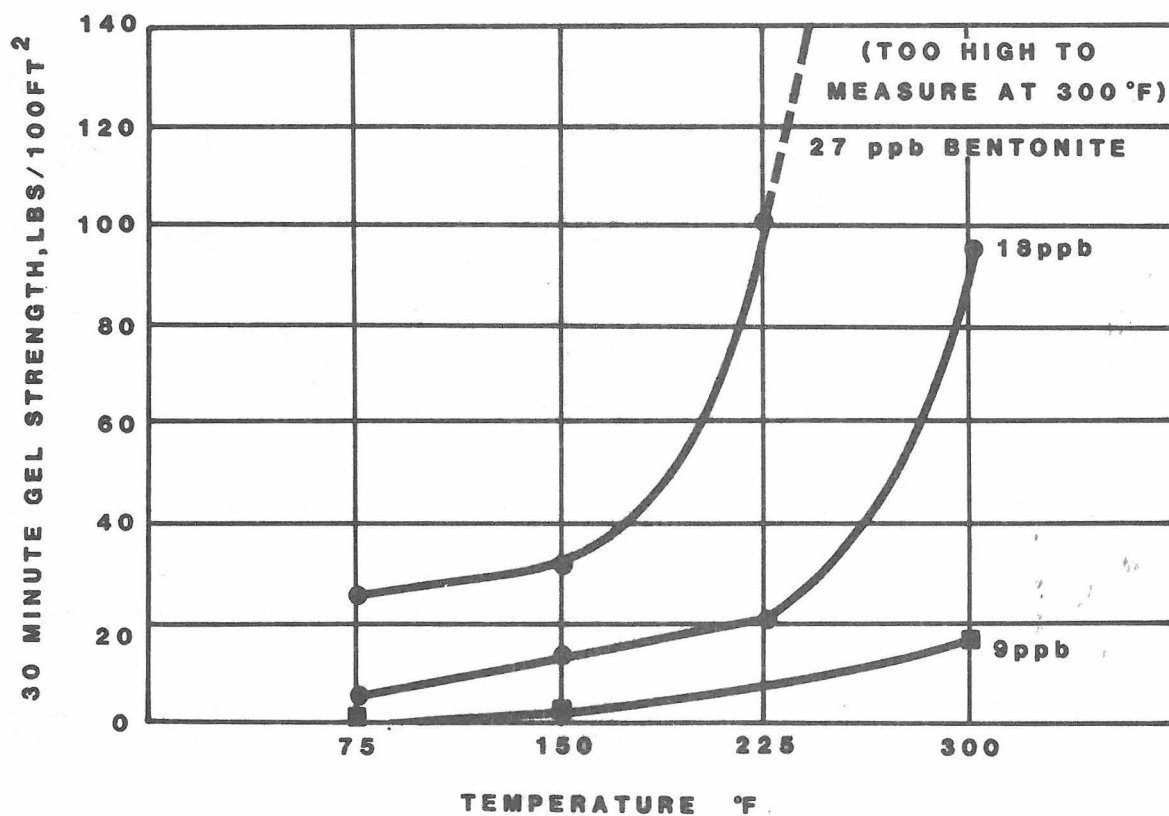
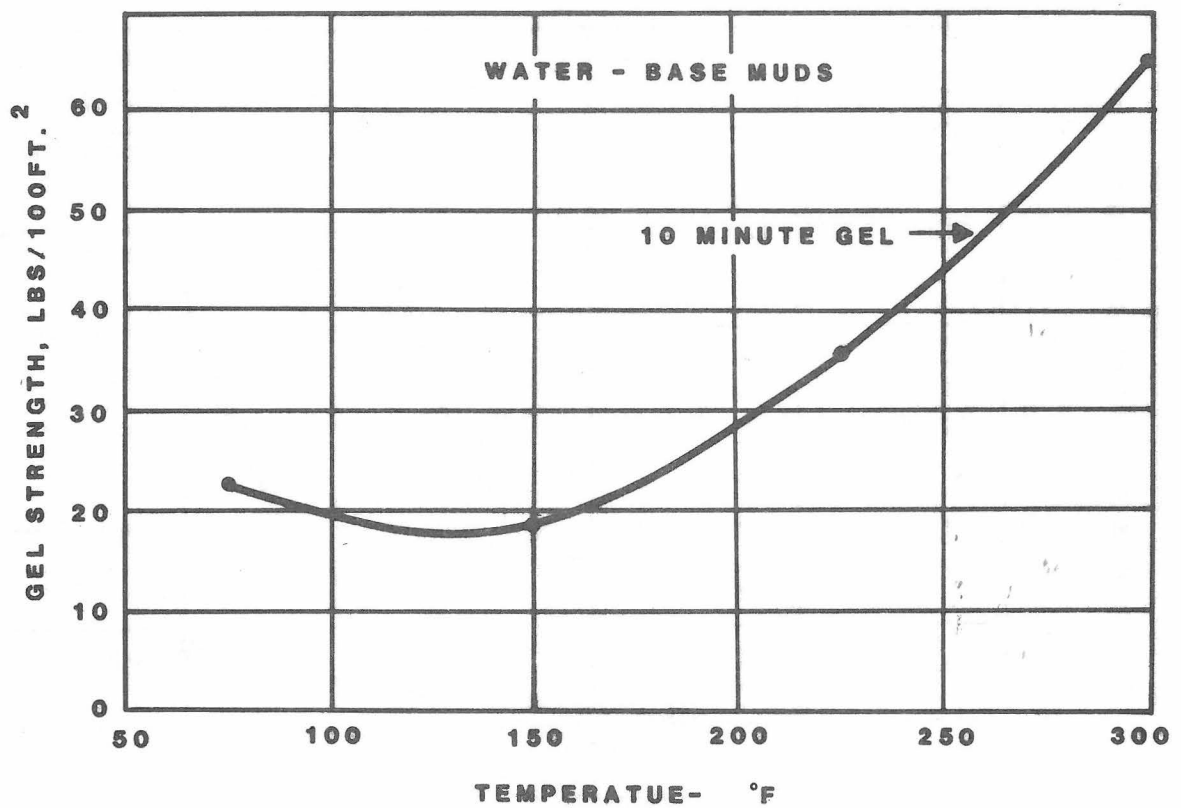


**FIGURE 18**  
**EFFECT OF TEMPERATURE ON 10 -MINUTE GEL**  
**STRENGTH (FROM ANNIS 1976)**



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