NEW MATERIALS IMPROVE THE CEMENTATION OF SALT FORMATIONS

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The cementing of wells penetrating massive salt formations has posed a number of problems over the years. The fact that some cements displayed poor characteristics in saline environments, and that conventional additives were of only limited use in these same systems contributed to these problems. Other additives, designed for use in salt water, were found to provide characteristics far from the optimum while, at the same time, causing detrimental effects on other slurry properties, notably rheology, thickening time and early compressive strength.

This paper describes the characteristics of new materials which provide superior performance in high-salt cement systems and illustrates, by way of field case histories, how these materials have helped improve primary cementing results in several areas.

INTRODUCTION

In several areas, the presence of salt domes and massive evaporite sequences causes problems in the drilling, completion, and long-term production of oil and gas wells which penetrate such zones. The principal problems caused by salt formations are two-fold:

1) The reactive nature of salt, and the minerals found associated with salt, can have deleterious effects on drilling fluids and cement slurries. The latter can be either severely retarded or accelerated depending on the composition of the initial slurry and the chemical nature of the salts involved.

2) The unusually high plasticity of salt causes it to deform, or flow, when subjected to stress. Thus, salt zones, under normal overburden pressures, will typically encroach upon a well drilled through them. The non-uniform nature of the flow can result in point-loading on casing strings, often causing failure and collapse.

In an attempt to minimize the risks posed by the presence of salt sections in the wellbore, the industry began incorporating salt, at various concentrations, into the cement slurries themselves. The first recorded use of salt as a component of oilwell cementing systems was in Gulf Coast wells penetrating salt domes during the early 1940's. This technique did not, however, see extensive use until the 1950's and 1960's when it became a standard practice in many parts of the Williston Basin of N. Dakota and Montana. Beach (1) published work in the early

1960's on the use of salt at low concentrations to accelerate the setting and early strength development of low density bentonitic cement systems. In 1963, Slagle and Smith (2) published a review of the uses of salt cements and promoted their use for the cementing of shales and sensitive clays. In some areas, this continues to be the main reason for using cement slurries containing salt. These authors also identified the principal properties of salt viz, acceleration at low concentrations, retardation at high concentrations, dispersion of gel-cement systems, increased slurry density, and expansion of the set cement. Several papers and patents in subsequent years, however, identified problems related to the performance of additives in high-salt systems. It became clear that conventional fresh water cementing materials were ill-suited to a saline environment and special additives were introduced to ameliorate the fluid loss and rheological properties of these high-salt slurries. Messenger (3) patented the use of a hydroxycarboxylic acid as a salt water dispersant in 1976 and several other patents were filed on similar materials by others. In spite of the detrimental effects of some of these additives on other performance characteristics (eg. thickening time) high-salt systems continued to be favored by many operators. In 1981, Patillo and Rankin (4) recommended the use of such systems, in combination with heavyweight casing, to solve pipe collapse problems. Other authors in the 1980's however, recommended a move away from high-salt slurries. Ford and Ramsey (5) suggested that semi-saturated salt systems, in combination with casing tension, improved the success ratio in Williston. Beach (6) expressed concern about the effects of fresh water zones on salt-saturated cements while Goodwin and Phipps (7) recommended the use of salt-free systems in the Williston Basin. These authors also suggested that displacement be carried out at very low rates to minimize erosion. Smith (8), in his now-famous checklist, still recommends the use of 20-31% salt when cementing massive zones but suggests that no salt should be used when covering plastic zones, to achieve a fast set and rapid strength development.

SALT ZONE CEMENTING - CURRENT PRACTICES

Essentially then, there are two principal, conflicting techniques used in the oil industry today for the cementing of salt zones. These feature the use of, either a "salt-poor", or a "salt-rich", cement slurry.

The so-called "salt-poor" slurry is prepared with either fresh water or water containing less than 15% sodium chloride by weight. At first glance, there appear to be several advantages in using such a slurry, from the point of view of performance under laboratory test conditions. The most obvious of these is the controllability of thickening time and the development of good early compressive strength. Also, special characteristics such as fluid-loss control or rheological properties suitable for turbulent flow, where required, are simpler to achieve with "salt-poor" slurries. Indeed, the majority of cement additives are designed to function primarily in freshwater-based systems. Unfortunately, laboratory testing does not take into account the changes in slurry performance which are likely to occur downhole. This, the dissolution of additional salt by the slurry's interstitial water will diminish fluid-loss control and, depending on the degree of contamination and the initial slurry design, may accelerate or retard the setting of the cement. The effects of such contamination can be quite severe. Testing has shown that the contamination of a fresh water system with as little as 10% salt can extend thickening time by 30%, increase downhole viscosity by 100% and increase filtration loss by almost 500%. Of course these effects vary and, if, for example, less than 10% salt were to be picked-up, the original thickening time would be shortened considerably. It would not be unusual for the thickening time to be cut in half. At the other extreme, in those cases where salt dissolution results in excessive retardation, the consequent reduction in early compressive strength will possibly leave the casing open to point loading by plastic salts. Even if the cement sets, the leaching, or dissolution, of the salt zone by the slurry will result in the creation of a gap at the cement/salt interface. It should be pointed out, however, that the plastic nature of the salt will tend to close this gap and give a good salt/cement bond within a short time.

The "salt-rich" slurry, normally, contains between 18% and 37% sodium chloride, by weight of water. Particularly, in the case of full saturation (37% BWOW), the advantages of using such systems should be obvious. Since the slurry interstitial water already contains a full complement of dissolved salt, it will not leach further material from the surrounding salt zone. This will ensure that slurry characteristics remain as designed and ensure good physical contact between the salt zone and the cement sheath after setting. Historicallly, however, these high-salt systems have had a number of problems associated with them. Recent concerns regarding the use of "salt-rich" cement systems have centred on the rate at which they develop compressive strength. In fact, normally, the final compressive strength of "salt-rich" systems is not substantially different from that of fresh water systems, at similar densities. The early compressive strength, on the other hand, at times of less than 24 hr. may be significantly lower and, depending on the slurry design, the cement may not even be set. As discussed above, the main reason for this type of behaviour stems from the incorporation of conventional salt-water fluid-loss additives and dispersants (i.e. celluloses and organic acids), into the design. These materials are fairly powerful retarders and act, in synergy with the salt, to produce long thickening times and low early strengths,the latter being particularly significant at BHST below 200 deg. F (93 deg. C). Fortunately, it has since been shown that a new family of additives is capable of providing both excellent control of fluid-loss and rheology in salt-rich slurries while providing controllable thickening times and rapid development of compressive strength.

NEW ADDITIVES

Over the years, numerous patents have been filed on novel cementing products for use in salt-zone cementing. Many of these have featured new types of fluid-loss control additive and some have addressed the problems of rheological control in the high-salt environment. Almost without exceptions, however, each of these materials has demonstrated a significant detrimental effect on some other slurry property. Recently, new Anionic Aromatic Polymers (AAP's) have been identified which, simultaneously, impart to salt-rich cement slurries improved fluid-loss control and exceptional rheological properties. At the same time, these materials do not significantly extend the slurry thickening time nor impair the compressive strength development of the cement. Thus, protection can be afforded to casing strings, in plastic zones, even at very early times after completion of the cement job. As shown in Table 1, compressive strengths at moderate static temperatures can exceed 1000 psi in less than 8 hours, with such systems. This compares with zero strength at 8 hours for conventional, fluid-loss controlled salt-rich systems. Indeed, attempts to improve fluid-loss control performance to values comparable with AAP slurries by, for example, using carboxyl-substituted celluloses, can produce systems which may show no strength for times in excess of 24 hours while the new AAP slurries will have developed compressive strength values of 2000 psi, or greater, thus offering considerably improved protection to the casing string during the first critical hours after cementing. An obvious advantage offered by these AAP's, is their ability to be used even at loss BHCT's. Previously, the inclusion of fluid-loss control additives, or friction reducers, was contra-indicated in salt-rich systems when circulating temperatures were below approximately 150 deg.F due to the excessive retarding effects of the conventional additives. AAP systems still display acceptably short thickening times (<6 hours) and good early strength development when circulating temperatures are as low as 120 deg.F.

Table 1 also demonstrates the exceptional rheological properties of AAP slurries, both at surface and under downhole temperature conditions. Such properties permit displacement at reasonable annular velocities, without undue friction pressure. This, in turn, improves displacement mechanics and helps ensure that mud removal is accomplished in an efficient manner. The net effect of these AAP's is to improve the probability of a successful cement job by minimizing the risk of bridging, by enhancing displacement mechanics, and by providing early casing protection from plastic salt.

SALT-ZONE CEMENTING - JOB DESIGN CONSIDERATIONS

Normally, when massive salts are penetrated, salt-saturated or oil-based muds are used in the drilling operation. These muds minimize the risk of dissolution, and consequent washout, of the zones in question during the drilling phase but necesitate careful attention to detail in the design of cement jobs.

Invariably, both types of mud are incompatible with cement slurries and require the use of properly designed spacer fluids. Particularly when oil-based muds are in use, it is important to obtain relevant geological/lithological date of the salt zone composition. In such cases, magnesium salt deposits, which would normally be dissolved by water-based drilling fluids, may cause a "flash-set" when contacted by the aqueous cement slurry.

Salt-tolerant spacers are recommended for use in salt zone cementing, but it is important that compatibility testing, with the actual mud and cement, be performed prior to use. Appropriate surfactants must be incorporated into the spacer when oil-based muds are to be displaced. It is worth noting that the majority of surfactants are inactive in highly saline environments and it is therefore, imperative that only those which retain their surface-active properties at high salinity be selected. It is also recommended that a small volume of diesel, or paraffinic mineral oil in the case of environmentally-safe (low-tox) oil-based muds, be pumped between mud and spacer to provide some dilution of the mud and reduction of the particulate concentration at the mud-spacer interface.

In general, it is recommended that salt-rich slurries be used for the cementation of massive salt intervals. Possible exceptions to this general rule may be those cases where BHCT is very low (less than 120 deg.F, 49 deg.C), or where the cement slurry in the annulus will only contact the salt formations near the end of the displacement. In most cases, local conditions, and past experience, will play a large part in deciding exactly which type of slurry system will be used.

FIELD CASE HISTORIES

Williston

The Williston Basin in N. Dakota and Montana contains multiple salt formations which can cause a host of well completion problems. Case histories, electric logs and the technical literature support the fact that some of these zones are plastic and this, in turn, has led to numerous instances of casing collapse across these intervals. Table 2 shows the principal zones of interest, their composition and their subsurface depth. The most significant problems in Williston have occurred across the Charles salt which is the largest of these evaporite intervals. Cement systems used to cover this section in the past have included conventional API cements and various pozzolanic blends mixed with salt at concentrations ranging from zero percent up to full saturation (37.2% BWOW) and at densities varying from 13 to 16.5 lbm/gal. Typically, a Williston well is cased with two pipe strings - a 9 5/8" surface casing and either a 7" or 5 1/2" production longstring. The surface casing is normally set at depths ranging from 1500 to 3000 ft., with the shoe, in any case, lying at least 50 ft. within the Pierre shale. The lonstring may extend to depths in excess of 13000 ft. depending upon the targeted production horizon(s) and this may be cemented in two or three stages if hydrostatic and temperature differential limitations dictate. In many cases, borehole geometry logs of Williston wells display several washouts corresponding to the salt sections which have been dissolved or eroded by circulating mug. Cement bond logs run on these same wells, after cementing, often show areas of apparent 100% bond across the same intervals, a phenomenon indicative of plastic salt movement into the wellbore and against the casing string. Fig. 3 illustrates this point clearly. Such an event suggests that the cement placed in the annular space remained liquid or had low mechanical strength for a prolonged period of time, and that the mud displacement process was compromised by the poor hole geometry and relatively poor fluid rheologies. In contrast, the log in Fig. 4 is an example from similar wells cemented with AAP-type cement slurries. The acoustic logs clearly show a more uniform, improved response over the entire interval.

West Texas

Cement systems incorporating the high performance, multifunctional AAP's have been used in northern sections of the Permian Basin. These wells are currently being drilled and completed in either the Lower Clearford or Wichita formations to a depth of over 8000 ft. Typically, these wells are completed with either a deep surface pipe or an intermediate string of 8 5/8" or 9 5/8" casing through the Triassic group of interbedded sanstones and shales known as the Red Beds. The casing shoe is set at approximately 2500 ft. and is cemented using a variety of conventional cementing systems which meet railroad commission standards. Immediately below this casing point, wells traverse alternating salt and anhydrite layers in the Permian Rustler and Saledo formations. For this reason the drilling fluid for this interval (and the remainder of the well) is a 10.2 lbm/gal salt saturated brine. Cement systems for the production string have traditionally been designed with the brine environment in mind. Even through the cement slurries, used in the lower sections of the hole, never cross the upper salt zones, they normally contain sodium chloride at concentrations ranging from 5% to 18% BWOW. This is done in order to minimize the risk of undesirable interactions between the brine in the well and the cement slurry. Such interactions can result in premature set of the cement during displacement. Another well parameter which complicates the cement slurry design in these wells is the possibility of lost circulation in several zones, especially the Glorieta and the Wichita. Estimated fracture gradients are normally of the order of 0.7 psi/ft and, for this reason, extednded pozzolanic cement systems are used to achieve the desired fill-up. Attempts to improve the overall performance of these systems, by incorporating fluid-loss control additives, have met with varied success. Thus, efforts to achieve a fluid loss of less than 500 ml/30 minutes in a 12% BWOW salt, extended Class C system with conventional cellulosic agents resulted in a system with reduced early strength. Furthermore, this same system increased equivalent circulating densities (ECD) by as much as 1.4 lbm/gal due to the viscosifying effect of the cellulose additives. In contrast, an AAP system was designed which provided acceptable fluid-loss and improved early strength. The AAP system also displayed a very low viscosity allowing it to be placed at high rates with minimal friction pressure. Figs. 5 & 6 are simulations which illustrate how the use of this type of slurry can minimize the risk of fracturing a weak zone. The additional friction pressure arising from the elevated viscosity of the conventional system (Fig. 5) is predicted to exceed the fracture pressure of the zone. The AAP-system (Fig. 6) allows the job to be carried out within the simulated constraints of the well. Subsequent to these treatments, cement bond logs have shown excellent bonding over most of the open hole interval in these wells in Yoakum County.

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Table 1

PV mPA.s	TY	BHCT deg.F	PV mPa.s	TY	F/L ml/30min	TT Hr:min	BHST deg.F	Comp Str psi 8hr	24
1) 10.2	3.2	110	12.4	3.1	360	5:55	130	-	850
2) 41.6	28	110	32.2	55	448	7:04	130	-	600
3) 43.3	0.1	120	33.1	0.2	64	5:34	200	1350	2100
4) 300+	15	120	244	22	178?	12:00+	200	nil	2500
5) 41.5	0.2	140	22.3	1.3	30	4:21	-	-	-
6) 25.4	0.1	160	17.5	0.1	52	2:36	230	1450	2150
7) 300+	15	160	105	31.3	284	8:00+	230	nil	2040

System 1 - 50:50 Pozz:C + 0.5 gal/sk AAP + 12% BWOW NcCl mixed at 13.5 lbm/gal

System 2 - 50:50 Pozz:C + 1.0% CFLA + 12% BWOW NaCl mixed at 13.5 lbm/gal

System 3 - Class G + 0.4 gal/sk AAP + 30% BWOW NaCl mixed at 16.64 lbm/gal

System 4 - Class G + 0.8% CFLA + 0.1% HCA + 30% BWOW NaCl mixed at 16.64 lbm/ga

System 5 - Class G + 0.5 gal/sk AAP + 30% BWOW NaCl mixed at 16.64 lbm/gal

System 6 - Class G + 0.5 gal/sk AAP + 30% BWOW NaCl mixed at 16.2 lbm/gal

System 7 - Class G + 0.8% CFLA + 0.1% HCA + 30% BWOW NaCl mixed at 16.2 lbm/gal

CFLA - Cellulose Fluid Loss Additive

AAP - Anionic Aromatic Polymer

HCA - Hydroxycarboxylic Acid

Table 2

FORMATION	CLASS	TYPICAL DEPTH	TYPICAL THICKNESS
Pine	Salt	6700'	150'
Opeche	Salt	7100'	150'
Charles	Salt	8400'	500'
Mission Canyon	Pay	9100'	300'
Prairie	Salt	11500'	150'
Red River	Pay	13500'	100'

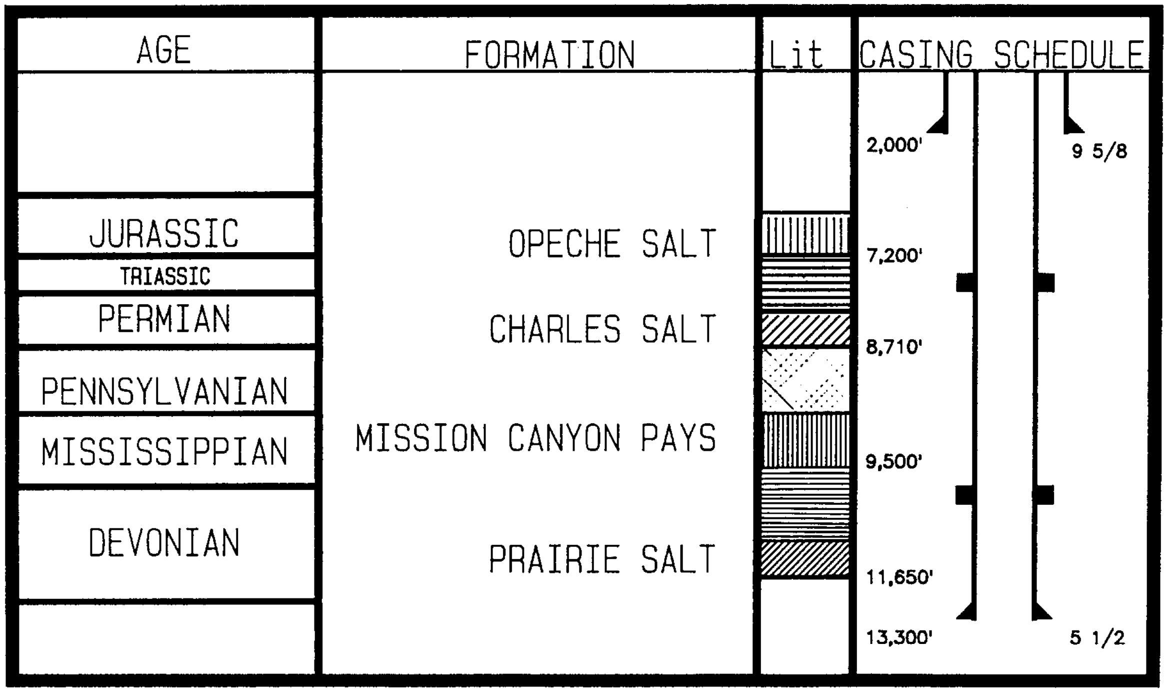

Figure 1 - Typical North Dakota stratigraphic column

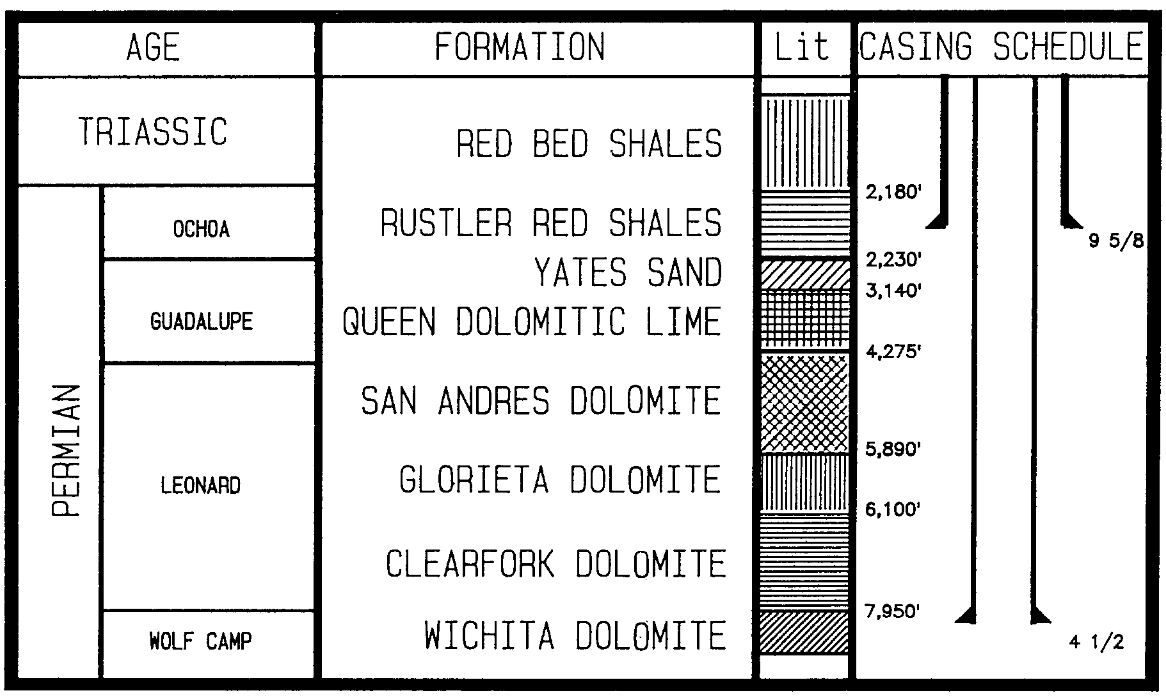

Figure 2 - Typical Permian Basin stratigraphic column

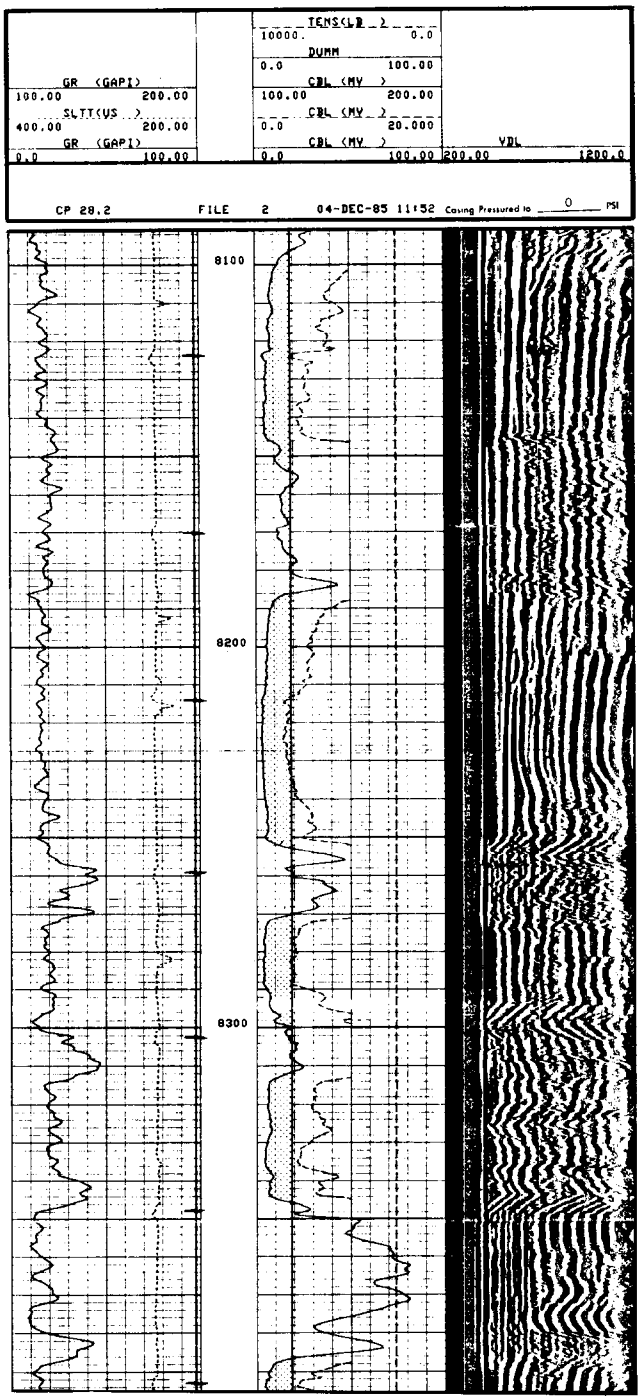

Figure 3 - Cement bond log from a McKenzie County North Dakota well — cemented with a conventional salt-rich cement system

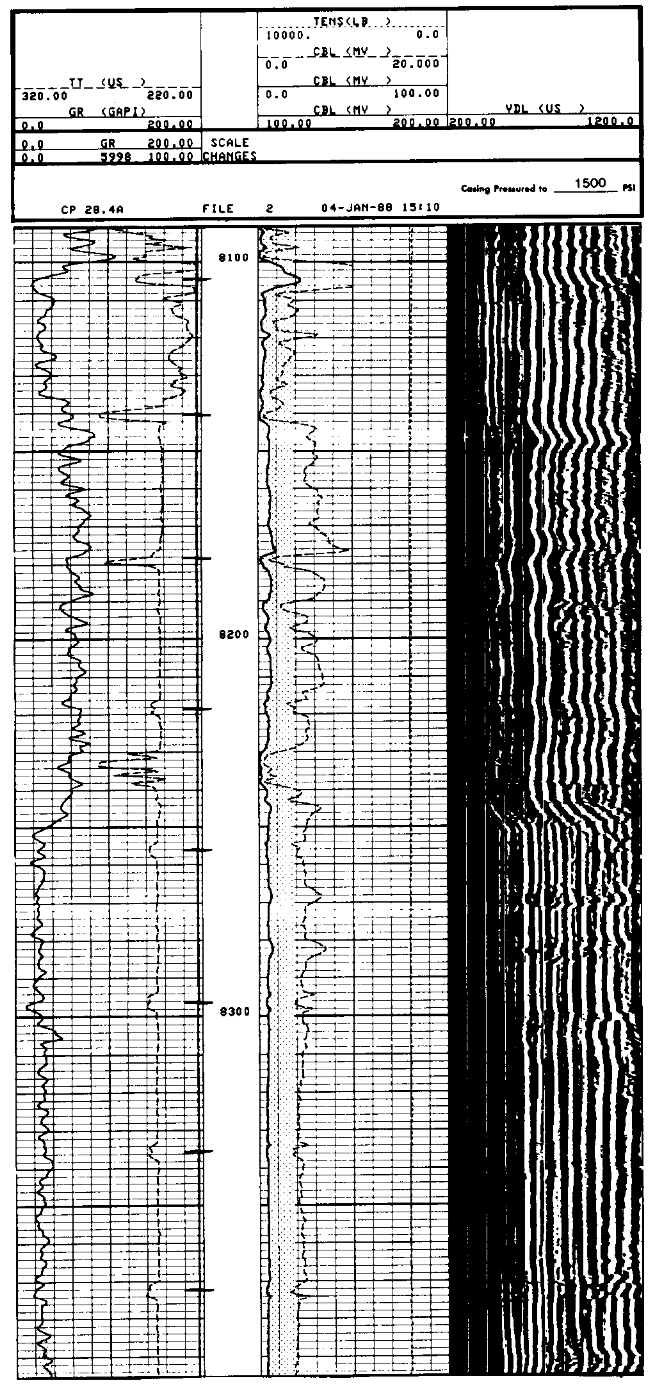

Figure 4 - Cement bond log from a McKenzie County North Dakota well — cemented with an AAP salt-rich cement system

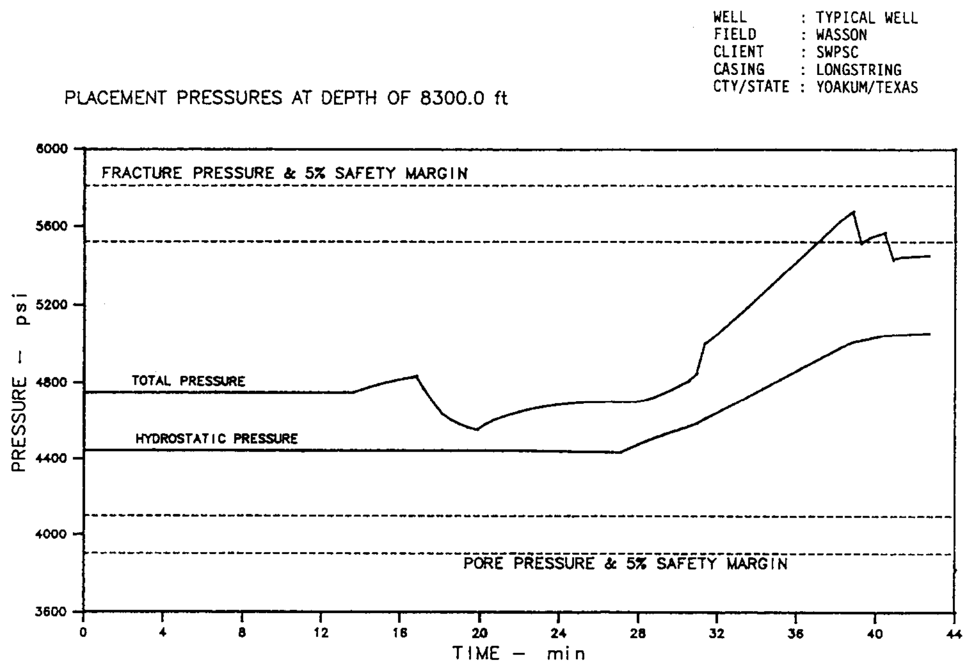

Figure 5 - Plot of total annular pressure
and the hydrostatic component

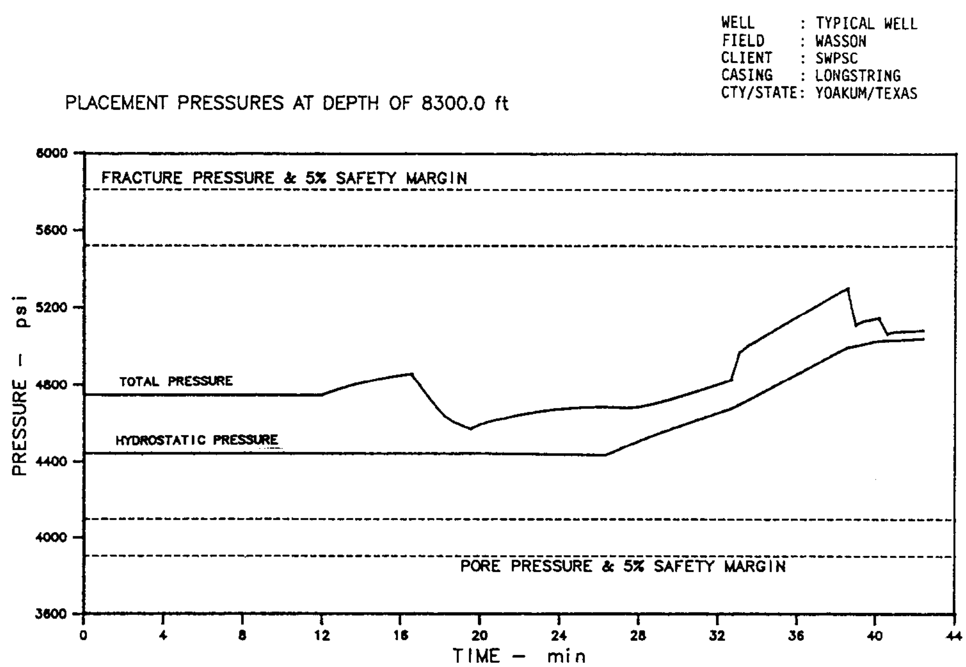

Figure 6 - Plot of total annular pressure
and the hydrostatic component