

FILE ORIGINAL

# *OPTIMIZING DRILLING FLUIDS IN HORIZONTAL WELLS - LABORATORY ADVANCEMENTS*

By

**Ron F. Bietz, Hycal Energy Research Laboratories Ltd.  
D. Brant Bennion, Hycal Energy Research Laboratories Ltd.  
F. Brent Thomas, Hycal Energy Research Laboratories Ltd.**

---

This paper is to be presented at the Fifth International Conference on Horizontal Well Technology, July 14-16, 1993, Amsterdam, Netherlands

---

## **Abstract**

At the advent of horizontal drilling technology, industry professionals used the expertise they gained with respect to drilling procedures and fluid design in vertical wells and applied it laterally to horizontal drilling applications. Because horizontal wellbores are much more sensitive to invasive damage due to increased exposure times, and the drawdown pressure available for inflow cleanup is often diminished due to augmented wellbore exposure and unique flow geometry, the direct application of vertical well technology was found to be inadequate in many cases.

An increased understanding of the various mechanisms of damage associated with horizontal drilling processes this has resulted in the development of improved drilling techniques as well as analytical tools for the evaluation of drilling procedures and fluid design in the laboratory environment.

## **Introduction**

The benefits of increased wellbore exposure are obvious, and because horizontal wellbore positioning

can yield significant advantages with respect to well spacing, once the challenges of placing the horizontal section within the target interval are mastered, many companies have embarked on aggressive horizontal drilling programs. Unfortunately, in many cases limited success, identified by the failure of the horizontal section to perform up to forecasted potential relative to nearby vertical wells, has prompted a second look at operating parameters and fluid utilization.

The optimization of drilling fluids is of paramount concern in horizontal wellbores since economic methods of removing drilling induced formation damage are rare and usually reservoir specific. The interaction between foreign fluids, natural and artificial solids, in-situ fluids and the reservoir porous media at full reservoir conditions can lead to a combination of formation damage mechanisms which can result in poor well performance and non-viable economics for a given horizontal well system.

Formation damage mechanisms and associated drilling procedures are discussed in the following



sections, as well as new experimental procedures relating to balanced and underbalanced drilling operations including foamed and nitrified or aerated systems. In addition, the evaluation of fluid performance in heterogeneous porous media is discussed.

### Mechanisms Of Formation Damage In Horizontal Wells

The character of formation damage in horizontal wells is best summarized as a conglomeration of mechanical and chemical interactions between the reservoir matrix and accessory mineralogy, drilling fluid bridging and rheology components, rock microfines generated by the drilling action of the drill bit, in-situ fluids, and drilling fluid filtrates.

A list of the mechanisms is taken from Bennion et al<sup>1</sup> and appears as follows:

1. Mechanically Induced formation Damage
  - i) Fines Migration
  - ii) Solids Entrainment
  - iii) Phase Trapping (Relative Permeability Effects)
2. Chemically Induced Formation Damage
  - i) Clay swelling
  - ii) Clay deflocculation
  - iii) Wax deposition
  - iv) Solids precipitation (asphaltenes, sulphur, diamondoids, hydrates, etc.)
  - v) Incompatible precipitates and scales
  - vi) Acid sludges
  - vii) Stable emulsions
  - viii) Chemical adsorption
  - ix) Wettability Alteration

More exotic mechanisms relating to Biologically induced damage and formation damage associated with thermal processes are omitted from this list.

### Core Preparation

In order to conduct valid drilling fluid leakoff experiments, the core material must exhibit the same wettability and saturation conditions as the in-situ reservoir material. Unpreserved or preserved core material is selected so as to closely represent typical reservoir quality matrix. Where wide distributions in permeability, pore throat size, pore size distribution,

etc. exist within one reservoir unit, it may be necessary to evaluate each unit individually. Emphasis during testing is usually preferentially given to samples representing the average to good quality reservoir. These portions of the reservoir generally tend to be the most severely affected by invasive damage and also represent the zones from which the majority of production occurs. Preserved core and restored core preparations are as follows:

Preserved Core - When core preservation is conducted for the purpose of maintaining in situ wettability and saturation, core samples should be removed to evaluate the amount of drilling fluid penetration and the validity of the initial saturation values. Wettability evaluations may also be employed when concerns are raised regarding wettability transformations resulting from drilling fluid contamination. Even though many companies are utilizing "low invasion" style coring equipment, core material can experience dramatic changes in saturation due to displacement and/or imbibition processes during the actual coring procedure. If preserved core fails to meet known reservoir saturation or wettability criteria, restoration of the core material may be required.

Restoration (Oil Zones) - Restoration of oil bearing formations is a well documented procedure. The process is initiated by vacuum saturating the clean and dry matrix material with formation water and circulating the water through the core material for 3 to 7 days to allow the core to come into ionic equilibrium with brine. Unoxidized crude oil is then slowly circulated through the core material at reservoir conditions for forty-two days to displace the sample down to irreducible water saturation and allow for a wettability transformation, toward neutral or oil wet condition, to take place if the core material has such a tendency.

Restoration (Gas Zones) - Restoration of gas bearing formations is often a simpler process in that gas is always a non-wetting phase, and for most dry gas reservoirs, restoration entails institution of an aqueous wetting phase saturation with the formation brine followed by a displacement procedure to evenly distribute this wetting phase. It is essential that the correct initial aqueous phase saturation be instituted in order to allow for accurate evaluation of aqueous phase trapping effects. It is possible that the initial reservoir rock is in a desiccated condition in situ where the initial water saturation is less than the true "irreducible" value (Bennion<sup>2</sup>, 1993).



### **Drilling Fluid Leakoff Experimentation - The Basic Concept**

The goal of the drilling fluid leakoff experiment is to subject reservoir rock, in a native state condition, to flow conditions which are typically experienced by the reservoir at the wellbore surface during the horizontal drilling process using actual reservoir and drilling fluids. In order to simulate these conditions rigorously, it is imperative that the drilling fluids are not "injected" into the core material, but rather are flowed past the core face at a representative over or underbalanced pressure condition which is determined by current reservoir pressure and hydrostatic mud column parameters. The displacement of the drilling fluid ensures that the fluid is sheared while in contact with the simulated formation face resulting in representative fluid properties.

### **Drilling Fluid Leakoff Experimental Procedure**

The drilling fluid leakoff experimental procedure is described by "Beatty et al<sup>3a</sup>" and is summarized as follows:

1. Initial permeability measurements are conducted with the appropriate hydrocarbon fluid at a low rate to minimize the potential for fines mobilization. Several rates are conducted in order to define the true permeability because permeability is often velocity sensitive at low interstitial velocities due to capillary forces and end effect phenomena. Multi-rate data is evaluated through the use of linear optimization calculations. This initial procedure is conducted on preserved or restored core material as discussed above, and is utilized to establish initial baseline permeability values which represent flow conditions in undamaged native state reservoir.
2. Representative drilling fluid used for the experiments are composed of actual field muds sampled from the well site following drilling of the horizontal section or synthetic mud systems generated to match expected field mud rheology and composition. Simulated muds are completed by generating rock microfines by grinding reservoir rock material down to the specified micron size tolerance to simulate suspended particle size distribution downstream of the solids control equipment and then adding these fines to the synthetic drilling fluids on a mass percent basis.

3. The flow direction is reversed, and the subject drilling fluid is displaced across the core face with a constant over or underbalance pressure exerted at the core face to simulate down hole conditions. A schematic of the experimental apparatus appears as Figure 1. This test phase is continued until the formation face experiences sealoff due to a build-up of mud and rock microfine materials and bridging agents (i.e. filter cake), the drilling time interval has elapsed, or a sufficient amount of leakoff has occurred such that representative filtrate volumes have invaded the matrix with a subsequent stabilization of the fluid leakoff rate.
4. During the leakoff exposure, filtrate invasion is monitored vs time by measuring the downstream effluent volume on the "reservoir" side of the mounted core sample. From this information, fluid leakoff character for the subject drilling fluid can be characterized in terms of sealoff potential, depth of filtrate invasion (Table 1) and leakoff rate (Table 2 - Figure 2).
5. Flow of hydrocarbon is established in the original flow direction and multi-rate permeability measurements are again determined at low rates to evaluate the post drilling fluid exposure regain permeability values. This displacement simulates inflow from the reservoir during the initial clean-up cycle, and the pre and post fluid exposure permeability measurements facilitate the characterization of the fluid in terms of percent permeability impairment (Table 3) and hypothetical skin factor. It is essential that a realistic drawdown pressure be applied during the clean-up phase to ensure that field representative data is generated.

### **Application Of Laboratory Data**

The laboratory data, generated through the use of conventional mud leakoff experiments, are used to obtain qualitative comparisons of various drilling fluid systems in conjunction with a specific rock type from a specific field. These data are used to reduce the risk of field fluid application by providing unstimulated regain permeability values which are indicative of horizontal hole post inflow cleanup by evaluating the damage potential of each fluid in the laboratory before the reservoir comes in contact with any of the potential test fluids.



The data, although providing quantitative impairment values for each drilling fluid tested, do not yield an overall impairment profile unless all of the permeability horizons and rock quality variations within the reservoir are tested independently.

Similarly, the leakoff data do not evaluate formation damage mechanisms independently; a gross permeability impairment value is determined which encompasses all damage mechanisms simultaneously. When the nature of the data is understood, the experimental process can be a powerful tool for evaluating potential fluids and operating parameters in a specified reservoir. Further test procedures are available for the evaluation of specific mechanisms of damage and will be discussed in following sections.

### **Damage Mechanism Isolation**

Laboratory experiments available for identification and isolation of damage mechanisms are summarized in Table 4.

When drilling fluid systems are evaluated, often certain fluids are more favourable based on economic, safety and/or environmental criteria. Evaluation of the formation damage mechanisms associated with the specific fluid can lead to slight modifications in fluid composition or drilling procedures which can alter the applicability of the fluid to the specific reservoir application.

### **Example of Mechanism Identification**

An example of the investigative process discussed above is as follows:

When the gross damage character for a certain bland drilling fluid was unfavourable in a subject reservoir, further investigation using drilling fluid filtrate sensitivity experiments revealed that the main damage mechanism of the fluid was a clay deflocculation type of phenomenon. This mechanism was directly related to in-situ Kaolinite clay content in the reservoir matrix (XRD Analysis) and severe sensitivity was detected by displacing drilling mud filtrate (all solids removed) through the core material and comparing the permeability to the filtrate with initial baseline permeability measurements conducted with equilibrium

formation brine.

Since deflocculation is associated with salinity and pH shocks in the pore space, pH modifications were made in the filtrate and the fluid was then found to be non-damaging. The deflocculation process was insignificant in neighbouring vertical wells because the sealoff potential of the mud was favourable and skin damage, though severe, was confined to a shallow depth of invasion in the near-wellbore region. Conventional perforations for the vertical wells reached the undamaged reservoir, therefore the fluid was assumed to be non-damaging.

An unstimulated (i.e. non-perforated) horizontal wellbore using this drilling mud exhibited poor inflow, but future modifications to the pH of the drilling fluid system yielded a more successful horizontal well program for the subject field. A combination of specific core tests and analytical petrographic work can often be very useful in isolating specific mechanisms of formation damage.

### **Advancements In Experiments To Simulate Balanced And Underbalanced Drilling Scenarios**

Advancements in laboratory experiments are due to a move by many in industry to horizontal drilling using near balanced and underbalanced (i.e. flow while drilling) techniques. This trend has identified many reservoirs which respond well to the change in drilling conditions and a shift in the interpretation of global formation damage phenomena has resulted. With conventional overbalance drilling conditions, mechanical processes related to the entrainment of mud solids and rock microfine particulates was often a dominant permeability impairment mechanism. Application of the balanced and underbalanced drilling techniques effectively eliminates the physical entrainment of the solid particulates in the pore throats.

**Experimental Considerations** - The experimental procedure is very similar to the one outlined previously, however, displacing drilling fluid across a formation face which is effectively flowing hydrocarbon is an additional feature of the simulation. Drilling fluid is circulated past the simulated wellbore face in an effort to simulate the turbulent fluid flow regime in the near wellbore region. This experiment



requires a modified apparatus, and additional data (i.e. permeability impairment vs exposure time) can be obtained with this technique.

### **Mechanisms Of Formation Damage In Underbalanced Systems**

Since the mechanical entrapment damage mechanism is deleted from the underbalanced drilling scenario (unless under-pressured regions of the reservoir are intersected by the wellbore), it may be assumed that formation damage is no longer of concern. This is an erroneous assumption because mechanical damage (and therefore chemical damage) processes can still be encountered even when underbalanced conditions are achieved.

Spontaneous imbibition of the drilling fluid, which is often a clear fluid, can occur in the near wellbore region. Reservoirs are often at initial aqueous saturations which are far below their irreducible values. Many reservoirs, particularly low quality reservoirs, will imbibe drilling fluids and the invading fluid can potentially reduce near wellbore permeability in several ways.

A trapped phase existing in the near wellbore region can significantly diminish the effective permeability of the matrix<sup>2</sup>. The depth of invasion of the imbibing phase will be dominated by the wettability of the reservoir, capillary pressure phenomena and the initial saturation profile.

Further damage may result from the invasive imbibition process due to the chemically induced formation damage mechanisms discussed previously.

### **Near Balanced Foam Systems**

Because balanced drilling conditions are sometimes difficult to achieve, foaming agents are added to the drilling fluid system, and inert and/or non-inert gases are co-injected with the drilling fluid to generate foam which possesses adequate rheology for solids removal (i.e. hole cleanup) while the net density of the fluid facilitates the appropriate fluid column weight to achieve balanced drilling parameters. These fluids exhibit their own unique advantages and disadvantages.

**Experimental Considerations** - An experimental apparatus has been developed (Figure 3) to facilitate the simulation of the drilling process with foamed fluids and multiple foam simulations have been conducted to confirm the viability of the technique. A foam cell continuously generates foamed drilling fluid and displacement of the fluid is conducted at overbalanced or near balanced conditions.

### **Crossflow Displacement Technology For Heterogeneous Reservoirs**

A common criticism of coreflow experiments is that the usual 3.81 cm diameter core sample lacks adequate cross sectional flow area to effectively simulate heterogeneous reservoir material. This concern is especially pronounced when evaluating carbonate rock types because carbonates often possess heterogeneous flow channels associated with an interconnected system of vugs or fractures. An effort to encompass a greater effective flow area is often attempted with full diameter samples by using the offcut end of the full diameter core material as the simulated sandface. This is a questionable procedure because, most reservoirs exhibit significant permeability anisotropy and the  $k_v/k_h$  relationship (i.e. vertical permeability vs horizontal permeability) indicates significantly reduced flow conductivity in the vertical direction.

**Experimental Considerations** - A new apparatus has been developed to facilitate the flow of fluids horizontally through a vertically sampled core. The minimum sandface exposure for a 10.16 cm (4 inch) core is 85.3 cm<sup>2</sup> which is 7.5 times the sandface exposure of a conventional horizontal small plug sample. Capability of this technology extends to an experimental sand face of 256 cm<sup>2</sup> however, suitable core length is required for a cross sectional flow area of this magnitude. This technique has also been tested repeatedly to ensure the viability of this technique.

### **Fracture Simulation Technology**

Unique drilling fluid properties are required for systems which conduct the majority of their production through secondary porosity systems such as fractures. Horizontal wells have found a specific application in reservoirs of this nature because the horizontal wellbore can intersect a greater number of fractures than could be achieved in conventional



vertical wells when the hole is oriented perpendicular to the fracture planes. Because the fracture system is the primary conduit for inflow, special considerations must be given with respect to drilling fluid bridging systems design so as to protect the fracture openings from natural and artificial solids entrapment.

Experimental Considerations - For reservoirs with fracture systems which dominate production, artificial fractures can be manufactured using actual core material, and precise fracture widths can be simulated in the laboratory environment. Natural fractures can also be evaluated, however the probability of intersecting fracture material with conventional vertical core is rare and oblique orientation often renders such samples unusable for physical experimentation. Specialized artificial bridging additives have been evaluated successfully in the laboratory during repeated testing.

### Field Case Studies

The authors have been involved in the evaluation of over one hundred reservoirs with more than three hundred drilling fluids being evaluated during the numerous studies world wide. Field case studies have been documented in the literature and consistent success with the experimental procedures has prompted this paper, however most of the data are proprietary and are held by organizations within the Petroleum industry. Available published data in the public domain for some of these studies are included in the list of references for this paper. Field and laboratory case studies documented by Beatty et al<sup>3</sup> depict experiments using 9 different drilling fluids which indicates a spectrum of permeability impairment factors ranging from 28.9% to 86.5% permeability loss. Utilization of a potential low damage drilling fluid resulted in horizontal production volumes which were 400% greater than wells drilled in similar quality intervals in the reservoir using conventional vertical orientation.

### Conclusions

1. Core flow experiments for the purpose of evaluating the risk associated with formation damage induced by various drilling fluids is a well established technology which can assist Petroleum industry professionals in developing more efficient and cost effective horizontal drilling programs.

2. Mechanisms of formation damage can be evaluated and isolated in the laboratory, and modifications to procedures and/or fluid compositions can result in better hole quality during horizontal drilling.
3. Advancements in laboratory procedures and development of new equipment has resulted in technology which can be used to evaluate the formation damage implications of contemporary field procedures such as balanced and underbalanced drilling techniques with clear and foamed drilling fluid systems.
4. Increased testing capabilities with respect to heterogeneous reservoir matrix is now possible using crossflow displacement technology.

### References

1. Bennion, D.B., Thomas, F.B., Bennion, D.W.: "Effective Laboratory Coreflood Tests To Evaluate And Minimize Formation Damage In Horizontal Wells", presented at the 3<sup>rd</sup> International Conference On Horizontal Well Technology, November 12-14, 1991, Houston, Texas.
2. Bennion, D.B., Cimolai, M.P., Bietz, R.F., Thomas, F.B.: "Reductions In The Productivity Of Oil And Gas Reservoirs Due To Aqueous Phase Trapping", paper CIM 93-24 presented at the May 1993 CIM conference in Calgary, Alberta, Canada
3. Beatty, T., Bennion, D.B., Hebner, B., Hiscock, R.: "Minimizing Formation Damage In Horizontal Wells: Laboratory and Field Case Studies", paper CIM 93-16 presented at the May 1993 CIM conference in Calgary, Alberta, Canada.
4. Bennion, D.B., Scott, J.A., Bennion, D.W.: "Detailed Laboratory Studies Of Chemically & Biologically Induced Formation Damage In The East Wilmington Field", paper CIM-92-44 presented at the June 1992 CIM conference in Calgary, Alberta Canada.



**TABLE 1**  
**EXPERIMENTAL DATA FOR THREE FLUID SYSTEMS**  
**LEAKOFF CHARACTER SUMMARY**

	Fluid "A"	Fluid "B"	Fluid "C"
Time to seal off	No seal off	No seal off	50 minutes
Total Leakoff Volume	1.70 cm <sup>3</sup>	0.44 cm <sup>3</sup>	3.66 cm <sup>3</sup>
Linear Filtrate Penetration Depth	*1.15 cm	*0.32 cm	*2.44 cm
* Assuming 100% of the pore volume is swept by filtrate.			



**TABLE 2**  
**EXPERIMENTAL DATA FOR THREE FLUID SYSTEMS**  
**DRILLING FLUID LEAKOFF RATE vs CUMULATIVE TIME**

Cuml Run Time (minutes)	Field Equivalent Rate (m <sup>3</sup> /m <sup>2</sup> /hr)		
	Drilling Fluid "A"	Drilling Fluid "B"	Drilling Fluid "C"
0.5	0.00263	0.00106	0.20208
1.0	0.00240	0.00097	0.04712
1.5	0.00223	0.00093	0.01780
2.0	0.00205	0.00088	0.00873
3.0	0.00187	0.00080	0.00785
4.0	0.00163	0.00072	0.00524
5.0	0.00151	0.00066	0.00366
6.0	0.00144	0.00059	0.00262
7.0	0.00128	0.00052	0.00209
8.0	0.00120	0.00049	0.00175
9.0	0.00113	0.00043	0.00157
10.0	0.00110	0.00040	0.00142
15.0	0.00083	0.00031	0.00098
20.0	0.00065	0.00022	0.00068
25.0	0.00056	0.00017	0.00047
30.0	0.00051	0.00013	0.00030
40.0	0.00046	0.00011	0.00010
50.0	0.00041	0.00009	0.00000
60.0	0.00039	0.00008	0.00000
75.0	0.00036	0.00007	0.00000
90.0	0.00034	0.00006	0.00000
105.0	0.00032	0.00005	0.00000
120.0	0.00030	0.00005	0.00000
150.0	0.00029	0.00005	0.00000
180.0	0.00027	0.00005	0.00000
210.0	0.00025	0.00005	0.00000
240.0	0.00023	0.00005	0.00000



**TABLE 3**  
**EXPERIMENTAL DATA FOR THREE FLUID SYSTEMS**  
**PERMEABILITY SUMMARY**

Test Phase	Permeability		% Change In Permeability
	( $\mu\text{m}$ ) <sup>2</sup> x 10 <sup>-3</sup>	mD	
<b>Fluid "A"</b>			
Initial Crude Oil (Direction #1)	4.12	4.17	0.00
Mud Leakoff (Direction #2)	--	--	--
Regain Permeability To Crude Oil (Direction #1)	0.59	0.60	-85.6
<b>Fluid "B"</b>			
Initial Crude Oil (Direction #1)	6.02	6.10	0.00
Mud Leakoff (Direction #2)	--	--	--
Regain Permeability To Crude Oil (Direction #1)	5.03	5.10	-16.4
<b>Fluid "C"</b>			
Initial Crude Oil (Direction #1)	3.95	4.00	0.00
Mud Leakoff (Direction #2)	--	--	--
Regain Permeability To Crude Oil (Direction #1)	3.61	3.66	-8.5
* Baseline			



**TABLE 4**  
**LABORATORY EXPERIMENTS TO EVALUATE**  
**MECHANISMS OF FORMATION DAMAGE**

<b>Damage Mechanism</b>	<b>Experimental Process</b>
Fines Migration	Fines migration (i.e. critical velocity) test <sup>1</sup>
Solids Entrainment	Drilling fluid leakoff test  Post leakoff Scanning Electron Microscopy (SEM) on longitudinal sections
Phase Trapping (Relative Permeability Effects)	Water trapping tests <sup>3</sup>
Clay Swelling	Drilling fluid filtrate sensitivity tests  Bulk X-ray diffraction  SEM with XES
Clay Deflocculation	Drilling fluid filtrate sensitivity tests  Bulk X-ray diffraction  SEM with XES



**FIGURE 1**  
**RESERVOIR CONDITION FLUID LEAKOFF APPARATUS**

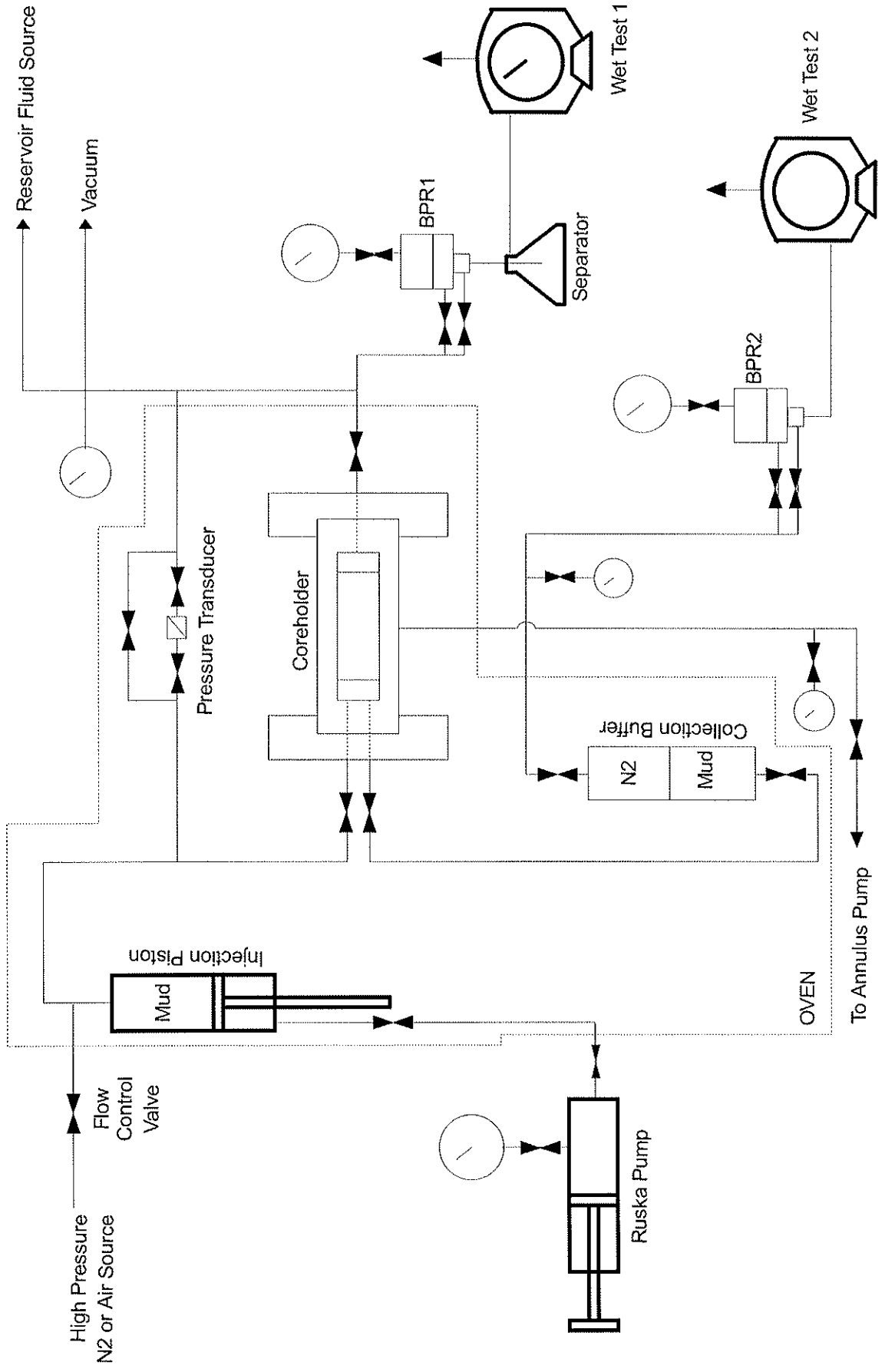
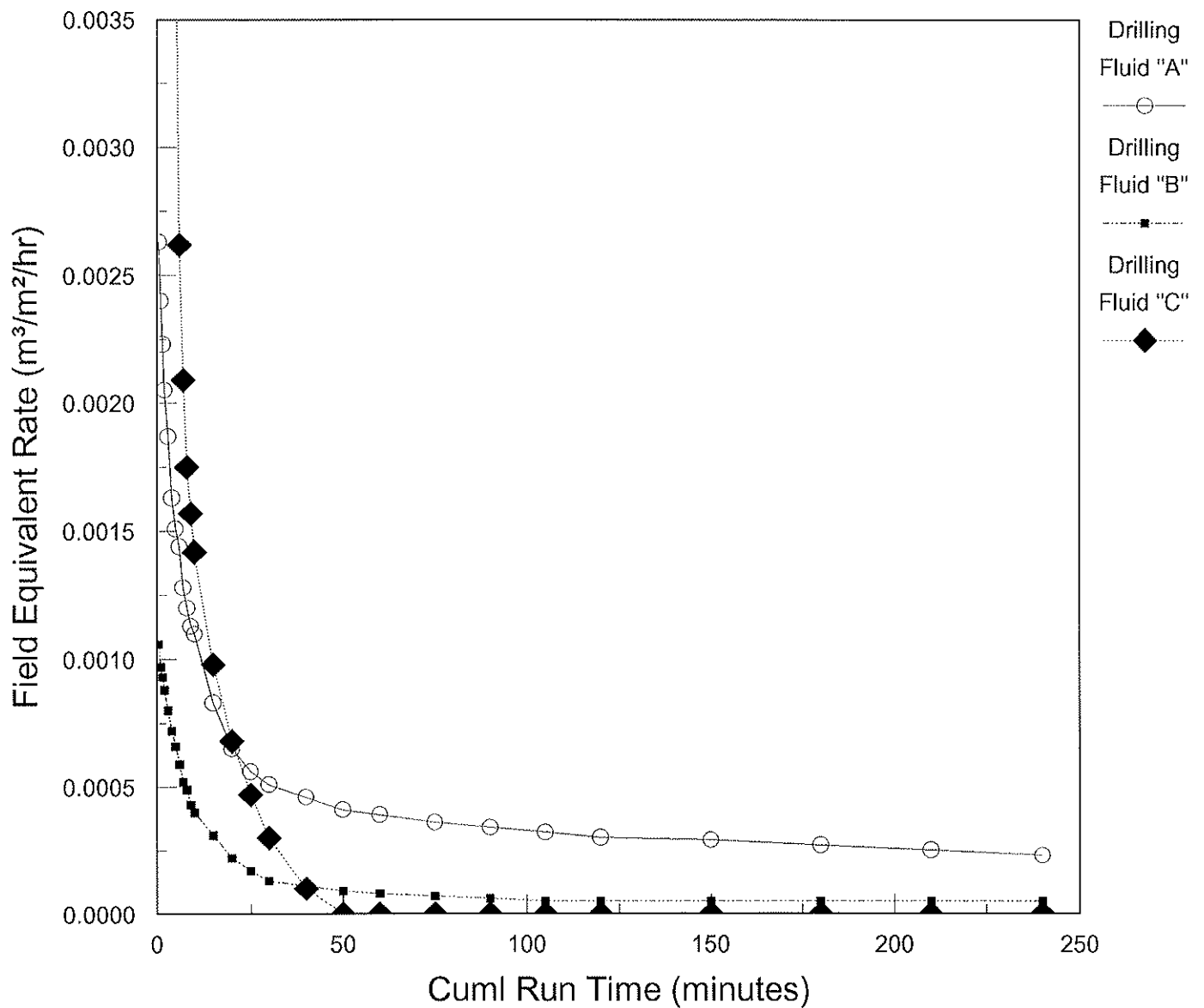




FIGURE 2  
DRILLING FLUID LEAKOFF RATE vs CUMULATIVE TIME  
EXPERIMENTAL DATA FOR THREE FLUID SYSTEMS  
FIELD EQUIVALENT RATE vs CUML RUN TIME





**FIGURE 3  
RESERVOIR CONDITION FOAM LEAKOFF APPARATUS**

