FINAL REPORT

Date: May 5, 2003

Title: **Development of New Types of Non-Damaging Drill-in and Completion Fluids**

Project Number: 26-98FT34174.000

From: **David B. Burnett, Harold Vance Department of Petroleum Engineering, Texas A&M University**

Goals and Objectives of Project

The goal of the project has been to develop new types of drill-in fluids (DIFs) and completion fluids (CFs) for use in natural gas reservoirs. Phase 1 of the project was a 24-month study to develop the concept of advanced type of fluids usable in well completions. Phase 1 tested this concept and created a kinetic mathematical model to accurately track the fluid's behavior under downhole conditions. Phase 2 includes tests of the new materials and practices. Work includes the preparation of new materials and the deployment of the new fluids and new practices to the field.

This is the final report on a program that has been operating for 7 years, including the last four years under the sponsorship of the U.S. DOE.

Accomplishments of Research Program

The project addresses the special problem of formation damage issues related to the use of CFs and DIFs in open hole horizontal well completions. The concept of a "removable filtercake" has, as its basis, a mechanism to initiate or trigger the removal process. Our approach to developing such a mechanism is to identify the components of the filtercake and measure the change in the characteristics of these components when certain cleanup (filtercake removal) techniques are employed.

The program has been an unqualified success. We have accomplished the following:

Development of New Laboratory Testing Practices

Established standard testing practices

Identification of key factors involved in formation damage

Established appropriate cleanup practices for removal of formation damage to optimize productivity.

Established New Guidelines for horizontal well completion practices

- Drill in fluid design and maintenance
- Cleanup fluid design and use

Development of new well drill in fluids

- Low solids polymer carbonate DIFs
- Polymer free high density DIFs
- Low Density Drill in fluid design

Performance Measurements in Field Well Completions

- Gulf of Mexico PC DIF
- North Slope Horizontal Well Completion
- North Sea Completion
- Gulf of Mexico polymer free DIF completion

The research program that led to these advances has extended over 7 years and has been supported by 13 different industrial sponsors during this period. Three companies (Conoco, Shell, and TBC Brinadd) have been supporters in each of the years.

Funding has been used to equip and operate the Texas A&M Completions Laboratory in the Department of Petroleum Engineering. We have graduated 7 graduate students who have received their MS in Petroleum Engineering. And sponsors have reported that the information learned in the program was contributed significantly to their company's operating unit performance, over 10% increase in well productivity.

GPR

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DRAFT II

Development of New Types of Non – Damaging Drill-in and Completion Fluids

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Name & Address of Submitting Organization:

Texas Engineering Experiment Station
Global Petroleum Research Institute
Attn: David B. Burnett
710 Richardson Bldg.
TAMU-3116
College Station, TX 77843-3116

Abstract

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Development of New Types of Drill In Fluids

Th goal of the project has been to improve the performance of horizontal open hole completions in gas and oil reservoirs through development of both new techniques and new types of drill in and completion fluids that overcome many of the disadvantages of previous industry practices.

The project has taken a comprehensive approach to defining the nature of formation damage and taking steps to avoid it has set an example of how laboratory practices can be integrated into field applications. This effort also has shown how an investment in laboratory testing will pay off in significantly improved well performance in horizontal open hole well completions.

The DIFs have been developed to address the formation damage control issues highlighted by tests at the A&M Completions Laboratory as well as our industrial sponsors. TBC Brinadd, a sponsor, has commercialized DiPro™ and has licensed it exclusively to MI Drilling Fluids, LLC. This material is now being used in both Gulf of Mexico and in West Africa operations. At the time of this report (April, 2003) more than five field well projects have been reported.

Laboratory Tests

At the beginning of our project, the oil and gas industry had no model or correlation to provide the essential link between laboratory results and field results. Our team set out to predict DIF performance and express the performance in terms of two factors, regained permeability and breakthrough time. Using a systematic approach, the project developed a series of mathematical correlations to predict the removal of filtercake deposited by DIFs on formation sands. A database was created that included 101 experiments made by several private laboratories and by Texas A&M. These experiments were the basis of the empirical models that predicted regained permeability and breakthrough times.

Guidelines for Damage Free Completions

A set of guidelines has been developed to provide assistance to those involved with the construction of high productivity horizontal wells. These guidelines, based on detailed investigations into the nature of formation damage of commercially available drill in fluids and completion practices may be used in conjunction with an engineering team's well design program. These guidelines are contained in Appendix 1.

New Drill In Fluids

The data was analyzed to identify the formation damage trends and to find statistical correlations to predict regained permeability and breakthrough time. Laboratory work included tests with a linear-flow cell to measure regained permeability, and with a ceramic disk cell to predict breakthrough time. After performing statistical studies to identify and select key variables, three independent factors were chosen to include in the correlation process -drill solids concentration, cleanup fluid concentration, and temperature- separated for each type of DIF. The statistical process included the selection of variables, the experimental design, and the development of the correlations. This provided predictive models for formation damage and cleanup treatment for similar conditions presented in the field.

Additionally, to demonstrate that the guidelines developed from laboratory experiments are valid in field applications, we have performed a series of well audits over the course of the project. This exercise has been instrumental in linking laboratory tests results to field application.

Field Audits

This portion of the study applies the knowledge gained in the lab to actual case studies. It has included (1) a combination of laboratory work, (2) the monitoring of fieldwork where advanced well completion techniques have been applied, and (3) the performance analysis in wells where the techniques have been used. Through the analysis of well files (correspondence, personal interviews, test analyses, and other related data), the auditor studies the development of the well from the initial well plan through its production phase. The audit is designed to show that improved drilling and completion techniques result in more productive wells.

Disclaimer

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Acknowledgements

DOE Support for Project

We gratefully acknowledge the support of the National Energy Technology Laboratory – U.S. DOE for their continued support for the A&M program for four years. I would like to personally thank Mr. Gary Covatch for his assistance and forbearance.

CEA Support for Project

Industry support has been outstanding for more than five years. I would like to thank the Completion Engineering Association for their support and assistance in creating the first joint venture and continuing it through some tight economic times.

GPRI Support for Project

The Global Petroleum Research Institute's members have been supporters for four years. Their industry experience and insight has made the project successful. I would like to single out Richard Hodge of ConocoPhillips and the staff of TBC Brinadd. TBC has commercialized their new product DiPro and the industry is seeing the results of the introduction of this superior material.

Texas A&M Department of Petroleum Engineering Graduate Program

Gloria Garcia, Jason Lacewell, Richard Jeppsen, Aline Caixeta, Fernando Gutierrez, Gerardo Serrano, Jorge Falla, Gerrit Leeftink, Guofan Chan

Executive Summary

DE 26-98FT34174.000

Development of New Types of Drill In Fluids

An industry – government partnership created and managed by the Petroleum Engineering Department of Texas A&M University has been working for four years to improve the performance of horizontal open hole completions in gas and oil reservoirs. In that period, the project's participants have helped to develop both new completion techniques and new types of drill in and completion fluid that overcomes many of the disadvantages of previous industry practices.

The project has been instrumental in an effort to make the industry aware of the detrimental role of active drill solids in filtercake cleanup and formation damage. Its comprehensive approach to defining the nature of formation damage and taking steps to avoid it has set an example of how laboratory testing practices can be integrated into field applications. This effort also has shown how an investment in laboratory testing will pay off in significantly improved well performance in horizontal open hole well completions.

Laboratory Tests

A project sponsored by the CEA (Completion Engineering Association) was created by D. B. Burnett in 1995 to study formation damage and cleanup techniques of processes used in completions in horizontal, unconsolidated, open hole wells. In 1998, a contract with the U.S. Department of Energy (DOE) was awarded to Burnett and the Department of Petroleum Engineering to develop new types of fluids that could be used to drill and complete low pressure and depleted gas reservoirs. The goal of the project was to develop new types of drill-in fluids (DIFs) and completion fluids (CFs) for use in natural gas reservoirs.

At the beginning of our project, the oil and gas industry had no model or correlation to provide the essential link between laboratory results and field results. Our team set out to predict DIF performance and express the performance in terms of two factors, regained permeability and breakthrough time.

To predict breakthrough times and regained permeability, a complete statistical analysis was required. The team first chose the type of testing procedures, then selected the variables to be measured, designed the set of experiments, performed the experiments and the statistical analysis itself. That effort led to one of the main milestones in this research, individual regressions that predicted the performance of drill in fluids.

Once the nature of formation damage had been characterized, the task began to document the development of new types of drill in fluids and to measure the performance of these fluids in field operations. The project addressed the special problem of formation damage issues related to the use of CFs and DIFs in open hole horizontal well completions and introduced the concept of a "removable filtercake". The concept had, as its basis, a mechanism to initiate or trigger the removal process. The approach to developing such a mechanism was first to identify the components of the filtercake and then to measure the change in the characteristics of these components when certain cleanup (filtercake removal) techniques were employed. Three new fluids have been developed based on this program.

New Drill In Fluids

In the early 1990s industry developed new types of fluids known as drill-in fluids, to reduce drilling and completion induced damage, especially in horizontal open hole completions. A drill-in fluid (DIF) is defined as a combination drilling and completion fluid, specially formulated to optimize the production capability of a given production interval. As standard drilling fluids, the DIF's provide lubricity, inhibition, solids suspension, and borehole stability. Ideally, they also protect producing intervals by mechanically sealing exposed pore space openings in boreholes, stabilize wellbore during completion, and clean up easily.

Most DIFs contain solid materials. Solids are used as bridging agents to plug the surface of a formation matrix and as weighting material to control formation pressure. DIFs use viscosifiers such as biopolymers to provide gel strength and improve the carrying of the drill solids to surface. Experience proved to the industry that solids content of the drill fluid, and in particular drill solids, held the key to performance. If drill solids could be kept to low concentrations, then open hole completions performed well. If solids control was not achieved, significant formation damage occurred. The A&M project was one of the first industry research programs to address in detail this role of drill solids and to identify ways of predicting the impact of these materials. Laboratory tests were developed to measure the two key factors necessary to determining completion efficiency, (1) filtercake removal and regain permeability and (2) rate of filtercake removal (breakthrough time).

Using a systematic approach, the project developed a series of mathematical correlations to predict the removal of filtercake deposited by DIFs on formation sands. A database was created that included 101 experiments made by several private laboratories and by Texas A&M. These experiments were the basis of the empirical models that predicted regained permeability and breakthrough times. The data was analyzed to identify the formation damage trends and to find statistical correlations to predict regained permeability and breakthrough time. Laboratory work included tests with a linear-flow cell to measure regained permeability, and with a ceramic disk cell to predict breakthrough time. After performing statistical studies to identify and select key variables, three independent factors were chosen to include in the correlation process -drill solids concentration, cleanup fluid concentration, and temperature- separated for each type of DIF. The statistical process included the selection of variables, the experimental design, and the development of the correlations. This provided predictive models for formation damage and cleanup treatment for similar conditions presented in the field.

Additionally, to demonstrate that the guidelines developed from laboratory experiments are valid in field applications, we have performed a series of well audits over the course of the project. This exercise has been instrumental in linking laboratory tests results to field application.

Field Audits

Alpine Field, Alaska:
Garden Banks, Gulf of Mexico

This study compares the practices used in a case study to drill and complete three horizontal, openhole wells in the Alpine field on the north slope of Alaska. This study is a continuation of the work performed in conjunction with CEA-73. In the first phase of CEA-73, laboratory work was completed to study the most important parameters in drilling and completing openhole horizontal completions. This portion of the study applies the knowledge gained in the lab to actual case studies. It has included (1) a combination of laboratory work, (2) the monitoring of fieldwork where advanced well completion techniques have been applied, and (3) the performance analysis in wells where the techniques have been used. Through the analysis of well files (correspondence, personal interviews, test analyses, and other related data), the auditor studies the development of the well from the initial well plan through its production phase. The audit is designed to show that improved drilling and completion techniques result in more productive wells.

The main objectives of this research are:

1. Audit wellbore construction practices used in drilling and completing horizontal, openhole wells in the Alpine field of Alaska, focusing on the wellbore cleanup and drill-in fluid selection
2. Perform production analysis on early production data from the audited wells to determine the degree of formation damage and the results of cleanup methods

The performed well audit reflected good planning throughout the Alpine horizontal well program. State of the art technology was considered, researched, and applied throughout the process.

Using horizontal well decline type curve techniques, production data was studied to determine the degree of skin in each well. Results from the well test analysis indicate that there was a high level of impairment in the wells, indicated by the significant skin. It is suspected that despite good planning practices, the formation damage was caused by: inadequate cleanup design, polymer degradation, mud handling/carbonate sizing. Furthermore, the possibility of removing substantial amounts of this damage using the current methods is doubtful. Moderate remediation might be possible with altered cleanup practices.

April 25, 2003

Development of New Types of Non-Damaging Drill-in and Completion Fluids

Project Number: 26-98FT34174.000

David B. Burnett,

Harold Vance Department of Petroleum Engineering,

Texas A&M University

CHAPTER 1

Introduction: Background and Previous Work

In the past decade the drilling industry has undergone a significant change that has increased its efficiency and improved its technical capability many-fold. Today's high technology, high productivity wells in deep water basins around the globe are a direct result of the adoption of new technology in drilling equipment, drilling and completion practices, and new drilling and completion fluids. As an example of the industry shift to more productive wellbores, a comparison of drilling statistics for 2002 show that while the number of wells being drilled are down, well productivity is up. Additionally, drilling costs are holding stable while well depth is increasing.

It was not long ago (1995) that a survey of horizontal well completions in the Gulf of Mexico showed that more than 20% of the completions reported were classified as failures. Today that number is less than 5%, indicating that well failures from both mechanical problems and formation damage problems are down dramatically. One of the principle reasons for this increased efficiency has been the advancement in the technology of drill in fluids (DIFs) used to penetrate producing zones without significant formation damage.

As the technology to minimize formation damage was being developed, industry leaders were beginning to achieve successes in shallow gas reservoirs where deliverability is critical and any restriction in fluid flow to wellbores cause serious problems. Low pressure formations have begun to be seen as a high value resource because of our ability to drill and complete highly productive wells with minimum fanfare. The new technology is also being used in well re-completions into zones at lower pressures or depleted reservoirs. And as the offshore industry seeks ways of accessing smaller and smaller reservoir compartments, the importance of damage free completions becomes more and more evident.

The development of improved DIFs with less formation damage characteristics began with a number of companies joining together to identify the root causes for flow impairment and loss of productivity. Early it was recognized that damage was often observed in horizontal, open hole completions where drawdown from the reservoir is small or where filtercake removal was required prior to gravel packing.

The industry has recognized the importance of tests to measure cleanup characteristics of DIFs in the laboratory prior to field operations. Such testing requires considerable skill and time. When unexpected problems are encountered when drilling a productive interval, it is often difficult to choose the proper intervention or cleanup necessary to remove damage. Plugging of metallic screens produced by DIF filtercake deposited on the formation face matrix has deserved a strong interest from the oil & gas industry. The presence of whole filtercakes or degraded filtercakes in horizontal, non/perforated openhole completions (metallic screens) reduces the productivity of the well.

The research work discussed in this report has as its focus the examination of the effects of differing compositions of filtercakes on screen plugging causing the

permeability impairment and the DIF designs needed to minimize formation damage.

During the completion of a horizontal well, the metallic screens are lowered into the wellbore, while the filtercake is still on the wellbore wall. This external filtercake developed by the DIF against the sandstone face is considered a potential mechanical damage when the filtercake is "sandwiched" between the formation face and the metallic screen. In the early production of the well, the filtercake can contribute significantly to plugging the metallic screens or impairing their screen permeability, thereby reducing well productivity.[1,2,3] It is very important that the metallic screens be undamaged during and after the completion operations. However, a recent study develop by Burnett[4] has shown that production of filtercakes and filtercake residues from the borehole walls causes significant screen plugging.

Most DIF's are composed mainly of solids. Those solids are used as bridging agents to plug the surface of a formation matrix, as weighting material to cont During filtercake buildup, the particles suspended into the DIF's larger than the pore openings of the formation matrix are retained and bridge the formation. Once all the pore openings on the formation face become bridged, an external filtercake starts to establish on the borehole wall. The particle size distribution (PSD) of the filtercake should mirror the PSD of the DIF's. As the filtercake builds, it requires a specific size to fill each opening, void, or pore throat on the formation face. Once the particles are fitted tightly to the available openings, the filtercake tends to result in maximum particle packing, resulting in a filtercake with lower permeability and pore throat openings are controlled by the ultrafine material content present. In summary, the DIF's provide the specific concentration, the PSD and the chemical composition of the filtercakes. Consequently, the filtercake will be an accumulation of sized particles of calcium carbonate or salt, polymers, starches and polysaccharides.

The removal of the filtercake either physically or chemically has been the topic of many researchers. The physical removal merits special attention.[5] During the initial stage of production, the filtercake caused a restriction of flow, requiring a high differential to overcome it. One important feature relates to how the whole filtercake or residual filtercake is dislodged from the formation. The filtercakes can be detached easily or develop pinholes or tears, leaving a residual internal filtercake. The detachment of the filtercake is associated with the lift-off pressure concept introduced by Browns et al.[6] and it is called in this research the minimum dislodging pressure (MDP). This pressure promotes breakdown of the filtercake. The filtercake is stressed against the screen, and a large fraction of the particles are allowed to get through into the screen, causing the retention of solid material into its slots to produce its plugging. This plugging causes screen permeability impairment and consequently the productivity of the well is reduced.

On the other hand, the chemical removal of the filtercake has been tested using strong acids, oxidizers, and enzymes. The main objective of these treatments is to alter the bridging and weighting material (BWM) to cause an effective degradation of the filtercake[6,7] These treatments have resulted in partial degradation of the filtercake since the presence of insoluble drill solids such as silica and alumni-silicates in the filtercake hinder the dissolution of the filtercake, leaving tough, tenacious and rigid residual filtercakes.

The presence of drill solids affects the HCl clean up treatments depending on the kind of the drill solids. Clay blocks the pathway to the acid so that effective contact with the BWM for dissolution is diminished, whereas coarse material such as sand increases the channels into the filtercake, which allows an optimal HCl cleanup and a high percentage of the filtercake to be readily attacked for total dissolution.

The DIF suspension is influenced by many well-known factors: concentration, particle-size distribution, and chemical composition of the suspended solid particles. Remarkably, a significant part of the DIF's is made up of the BWM and the loss control material (LCM), and the drill solids incorporated during drilling operations. These DIF's are designed to produce a filtercake whose composition will be identical to the DIF's themselves.

The topics in the following chapters will be to analyze these factor and then to create a process to avoid those conditions that aggravate damage.

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CHAPTER 2

Laboratory Testing Practices

A comprehensive laboratory testing program was developed to evaluate the plugging mechanisms of metallic screens after cleaning up the filtercake developed on an unconsolidated core by two exiting drill-in fluids (DIF's). Two simulated drill solids; clay or 75-µm reservoir sand was added as drill solids to these DIF's. Poroplus^{TM} metallic screens developed by Purolator Products Company were used to simulate the sand control device. The DIF's tested included a sized-calcium carbonate (SCC) and a sized-salt (SS).

BWM solids containing calcium montmorillonite clay showed that the median size of the particles was substantially decreased and the ultrafine material content (particles smaller than 45 µm) was increased. BWM solids containing 75-µm sand as drill solids showed an increase of the median size of the particles with a decrease in the ultrafine material.

After the filtercake clean-up treatment and subsequent backflow, screen plugging evaluated in terms of regained-flow capacity was much more severe in the presence of the whole filtercake (after 3% KCl treatments) than in the presence of the degraded filtercake (after HCl acid treatments).

The test data show that when SCC filtercakes were removed by backflow, the smaller the particle size of the filtercake, the higher the minimum dislodging pressure (MDP) and screen plugging, and consequently the lower the regained-flow capacity. Coarse particle size of the filtercakes tended to result in minimum MDP, leading to higher regained-flow capacity and lower plugging of the screen.

Also, the results indicated that the hydrochloric acid treatment was more effective in removing the filtercakes than the 3% KCl treatment. Also, it was demonstrated that the use of HCl is much more effective in removing the filtercake formed by SS than in removing the one formed by SCC.

Basis of Testing Procedures

The plugging of metallic screens produced by DIF filtercake deposited on the formation face matrix has deserved a strong interest from the oil & gas industry. The presence of whole filtercakes or degraded filtercakes in horizontal, non/perforated openhole completions (metallic screens) reduces the productivity of the well. This research focuses in examining the effects of differing compositions of filtercakes on screen plugging causing the permeability impairment.

During the completion of a horizontal well, the metallic screens are lowered into the wellbore, while the filtercake is still on the wellbore wall. This external filtercake developed by the DIF's against the sandstone face is considered a potential mechanical damage when the filtercake is "sandwiched" between the formation face and the metallic screen. In the early production of the well, the filtercake can contribute significantly to plugging the metallic screens or impairing their screen permeability, thereby reducing well productivity.[1,2,3] It is very important that the metallic screens be undamaged during and after the completion operations. However, a recent study develop by Burnett[4] has shown that production of filtercakes and filtercake residues from the borehole walls causes significant screen plugging.

Most DIFs contain solid materials. Solids are used as bridging agents to plug the surface of a formation matrix and as weighting material to control pressure formation. DIFs use viscosifiers such as biopolymers to provide gel strength and improve the carrying of the drill solids to surface. Drill solids are tiny formation particles that become suspended into the DIF's, forming part of their solid material suspension. Therefore, the DIF suspension is influenced by many well-known factors: concentration, particle-size distribution, and chemical composition of the suspended solid particles. Remarkably, a significant part of the DIF's is made up of the BWM and the LCM, and the drill solids incorporated during drilling operations. These DIF's are designed to produce a filtercake whose composition will be identical to the DIF's themselves.

During filtercake buildup, the particle suspended into the DIF's larger than the pore openings of the formation matrix are retained and bridge the formation. Once all the pore openings on the formation face become bridged, an external filtercake starts to establish on the borehole wall. The particle size distribution (PSD) of the filtercake should mirror the PSD of the DIF's. As the filtercake builds, it requires a specific size to fill each opening, void, or pore throat on the formation face. Once the particles are fitted tightly to the available openings, the filtercake tends to result in maximum particle packing, resulting in a filtercake with lower permeability and pore throat openings are controlled by the ultrafine material content present. In summary, the DIF's provide the specific concentration, the PSD and the chemical composition of the filtercakes. Consequently, the filtercake will be an accumulation of sized particles of calcium carbonate or salt, polymers, starches and polysaccharides.

The removal of the filtercake either physically or chemically has been the topic of many researchers. The physical removal merits special attention.[5] During the initial stage of production, the filtercake caused a restriction of flow, requiring a high differential to overcome it. One important feature relates to how the whole filtercake or residual filtercake is dislodged from the formation. The filtercakes can be detached easily or develop pinholes or tears, leaving a residual internal filtercake. The detachment of the filtercake is associated with the lift-off pressure concept introduced by Browns et al.[5] and it is called in this research the minimum dislodging pressure (MDP). This pressure promotes breakdown of the filtercake. The filtercake is stressed against the screen, and a large fraction of the particles are allowed to get through into the screen, causing the retention of solid material into its slots to produce its plugging. This plugging causes screen permeability impairment and consequently the productivity of the well is reduced.

On the other hand, the chemical removal of the filtercake has been tested using strong acids, oxidizers, and enzymes. The main objective of these treatments is to alter the BWM to cause an effective degradation of the filtercake[6] These treatments have resulted in partial degradation of the filtercake since the presence of insoluble drill solids such as silica and alumni-silicates in the filtercake hinder the dissolution of the filtercake, leaving tough, tenacious and rigid residual filtercakes.

The presence of drill solids affects the HCl clean up treatments depending on the kind of the drill solids. Clay blocks the pathway to the acid so that effective contact with the BWM for dissolution is diminished, whereas coarse material such as sand increases the channels into the filtercake, which allows an optimal HCl cleanup and a high percentage of the filtercake to be readily attacked for total dissolution.

Filtercake Removal Techniques

The most important objectives of the laboratory work presented in this research are aimed at investigating how to remove filtercakes by using potassium chloride (KCl) or hydrochloric acid (HCl) and how residual filtercakes left against the unconsolidated core plug metallic screens. The project addressed various characteristics of the filtercake altered with simulated solids and the effect of these drill solids in filtercake removal prior to installing a metallic screen into the wellbore. The following aspects were taken into account to carry out the laboratory work:

1. The initial laboratory work focused on determining of the particle size distribution (PSD) of the weighting and bridging materials used in two existing DIF's, SCC and SS. The most important components of the DIF's, the BWM, were altered by two types of simulated drill solids, clay and 75-μm sand, to observe their PSD performance.
2. Scanning electron microscopy (SEM) imaging was used to study the internal structure of the filtercake developed by original SS and SCC weighted at 10.5 ppg. Then the simulated drill solids were added to the DIF, and new filtercakes were built up. SEM was used extensively.
3. The final area of experimental investigation addressed the behavior of the backflow through the whole filtercake and residual filtercake. This laboratory work was divided into three sections. The first set of tests compared the backflow of the filtercake after 3% KCl cleanup. The second section examined how DIF filtercakes impaired the screen permeability. The last area of the investigation dealt with the cleanup or removal process of the filtercake using 5% HCl and 15% HCl at two different temperatures. Afterwards the residual filtercakes were backflowed through a 125-μm screen to observe its plugging.

Experimental Materials

Drill-In Fluids

New types of fluids, drill-in fluids, have been developed to reduce drilling and completion induced damage, especially in horizontal openhole completions where bypassing damage by perforation is not usually an option. A drill-in fluid (DIF) is defined as a combination drilling and completion fluid, specially formulated to optimize the production capability of a given production interval.[10] As standard drilling fluids, the DIF's provide lubricity, inhibition, solids suspension, and borehole stability. Ideally, they also protect producing intervals by mechanically sealing exposed pore space openings in boreholes, stabilize wellbore during completion, and clean up easily.

DIF systems are designed with special bridging and weighting materials (BWM) to minimize invasion and to allow more thorough removal than conventional drilling fluids. Several BWM's are designed to minimize stages and time required to clean up wells before production. DIF's with easy-to-remove agents reduce completion costs. Other BWM's have been designed to form effective filtercakes for instantaneous leak-off control. Two types of drill in fluids are used in here, Sized Salt and Sized Calcium Carbonate. Their chemical composition is presented in Table 1.

Table 1 - Composition of the SS and SCC DIF's

Type of Fluid	Composition
Sized-Salt	500 cc H_2O, 170 gm NaCl, 104 gm Bridgesal™, 64.5 gm Plugsal™, 6.40 gm Fl-7 Plus, 1.44 cc Defoam
Sized-Calcium Carbonate	376 cc H_2O, 24 gm KCl, 120 gm NaCl 63.6 gm Carbwate™, 0.75 gm Visplus™, 8.25 gm FL-7 Plus, 2 gm pH buffer, 1.14 cc Defoam

Filtercake

The filtercake is formed when differential pressure is applied on a DIF during the drilling operation. Solid particles suspended in the DIF are retained at the surface of the porous medium, leading to the formation of the filtercake. Filtercake thickness and compaction increases with time. The filtercake typically comprises solids, either starches or cellulose polymers and calcium carbonate or sodium chloride particles, with water as the liquid interstitial.[13] DIF's are designed to prevent liquid and solid invasion into a permeable formation by bridging and sealing with a readily removable, ultralow-permeability filtercake. These characteristics are achieved by selecting a suitable size range and particle size distribution of soluble solids for bridging the pore openings between formation sand grains.

In the filtercake formation, the sizes of the particles present in the DIF often cover a wide range. While the majority of the particles are retained to form a filtercake, a small amount of finer ones may be retained into filtercake. Therefore, the permeability of a filtercake depends upon the extent of the compression to which it is subjected, as well as the amount of fines retained within the filtercake.[16] It has been demonstrated mathematically that a high content of ultrafine material produces a remarkably impermeable filtercake,[16] which precludes the movement of fluid through its pore throats and avoids any fluid invasion.

Drill Solids

During drilling operations, clay and other fine particles can be released from the formation when the forces acting on them can no longer keep them on the pore spaces. These particles constitute the drill solids that become suspended into the DIF and form part of its filtercake. Clay and sand are the two types of drill solids used in this laboratory work.

Poroplus Metallic Screen

Recent developments in porous sintered media technology have prompted its application in the manufacture of metallic screens for oil and gas wells. A Poroplus™ metallic screen is shown in Fig. 1. The screen is made from Poroplate™ sintered filter media. Poroplate™ filter media are made from layers of woven stainless steel wire mesh sintered together into rugged porous material.[18] Each wire bonds to the adjacent wires and layers of the screen, maximizing strength and durability. The various wire mesh layers are selected to achieve accurate particle size control while maximizing flow rates.

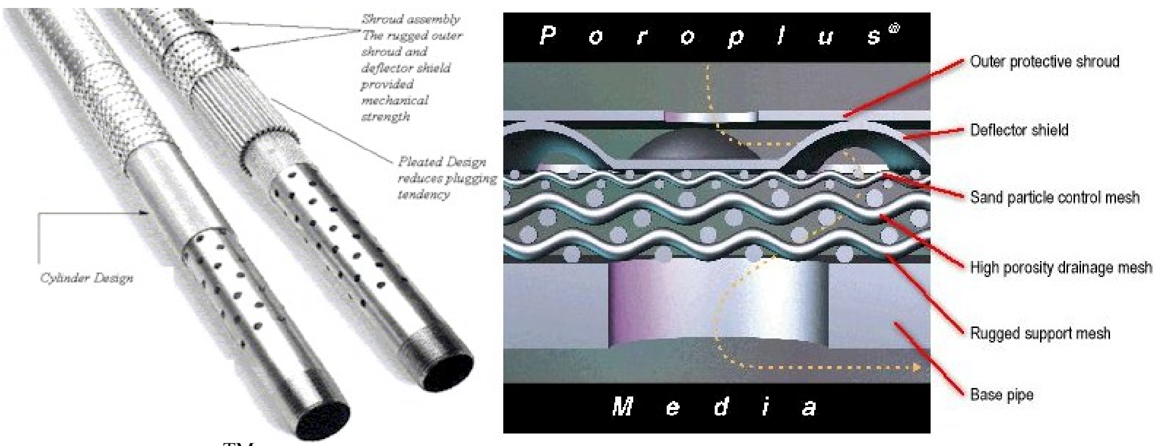


Fig. 1 – Poroplus™ metallic screen design (Courtesy of Halliburton)

Laboratory Procedures

Dry Sieve Analysis

A sifter was used to obtain the particle size distribution. The particle-size analyzer contains an assortment of sieves arranged according to decreasing opening sizes. The mesh sizes used were 300, 212, 106, 90, 75 and 45 μm. The solid material was placed over the top of the sieve, and a cover was put on the top and latched. The set of sieves was placed into the sifter and the door was closed. The sifter was turned on, the pulse and sift-sequence values were set, and the sifter was started. The sifter separates the solid grains by size. Each screen was weighed before and after the separation. The weight trapped on each screen was determined by difference between these weights. On the basis of the previous results, a cumulative weight percentage of grains trapped for each screen was calculated.

SEM Imaging

The microscopic structure of the DIF filtercakes built up under static conditions was observed with a Cameca SX-50 electron microprobe. This device has the capability of combining the X-ray elemental analysis of inorganic materials at the micron size scale with medium scanning electron microscopy. Low and moderated magnifications from 62X to 20,000X can be obtained. Additionally, its energy-dispersive X-ray spectrometry (EDS) allows qualitative chemical analysis of the observed material. The filtercakes developed by SCC and SS DIF's with and without drill solids (clay and 75-μm sand) were imaged.

Conoco Cell Procedure

The laboratory techniques used in this study were developed to simulate and characterize the screen plugging that occurs during the initial completion of a horizontal well. These tests have allowed the quantification of the mechanism involved in the plugging of the screens. Testing procedures were developed by CEA 73 and were implemented by Burnett at Texas A&M.[22]

Conoco Inc.[9] developed a test device called a linear flow cell, [2,4] shown in Fig. 2. This cell was designed to measure the extent of metallic or pre-packed screen plugging in terms of regained permeability and to gauge a DIF's' capacity to form a thin, low-permeability filtercake. The cell parts consist of a 1.95-cm diameter and 1.572-cm length sand module pack to simulate the borehole wall and a 3.4-cm diameter disk of metallic screen to simulate the openhole completion. The metallic screen disk was mounted on screen holder, facing the unconsolidated core packed in the sand module. Afterwards, these parts were assembled in the cell body. The test procedure included wellbore filtercake buildup, core flow-regained permeability testing, and wellbore filtercake removal or cleanup.

The following are the steps described in more detail:

- The sand is firmly packed into the core holder and Soltrol, which is a type of oil used for laboratory purposes, is injected through the sand with the intention of measuring the initial permeability of the sand (step 1 in Figure 3). Then, as Soltrol is injected into the cell it flows through the unconsolidated sand and goes out the cell to a balance, in that way Soltrol leak off can be weighed in a certain interval of time. This is done so Darcy's law equation (Equation 1)[11] can be used to calculate permeability.

$$K_i = \frac{Q_o \times \mu_o \times L_{Core}}{A_{Core} \times \Delta P} \quad \text{.......Eq 1}$$

Where:
Qo (cc/sec) is measured, having Soltrol mass flowed through the sand and time.
ΔP (atm) is the sand flow resistance to the Soltrol.
μo (cp) is given.
Lcore (cm) and **Acore** (cm^2) are dimensions given.
K_i (md) initial permeability

Once the initial permeability is measured, the sand module (core holder) is backed off to create a clearance between the sand module and the screen holder in the cell assembly and to allow filtercake build up during drill-in fluid displacement. Nitrogen is used to put pressure in the system (200 psi) for two hours, giving enough time for the filter cake to be formed**. Step 2 in figure 3** depicts this step.

After the this period of time is over, the remaining drill-in fluid is removed and a solution of HCl is injected and flowed across the filter cake for about 45 minutes. (Step 3 in figure 3 describes this step)

Once the clean up fluid treatment has been displaced, it is assumed that the filter cake was removed and that permeability was restored. In this step the sand module is screwed back to its original position and Soltrol is injected through the sand so the final permeability is obtained. Once the initial (K_i) and final permeability (Kf) are measured, the regain permeability is obtained by **equation 2. (Step 4 in figure 3)**

Discussion and Results

Particle Size Distribution

The measurement of particle size distribution of the weighting and bridging agents that compose the DIF's as well as their mixture with simulated drill solids should, in principle, be indicative of the filtercakes' inclination to plug the metallic screen slots once it is dislodged. The objective of these PSD tests was to find some sort of correlation with the filtercake removal and the extent of plugging as described in later section.

The potential damage of solids depends primarily on their size, dispersed character, and interaction with other DIF additives. The most damaging sizes[21] with respect to the screen plugging are in the ultrafine size ranges, which are represented by particles smaller than 45 µm in most sieve analyses. Tables 2-5 shows typical size ranges for various solids used in this research.

Table 2 - Size range classification	
Classification	Size Range, µm
Medium	75-300
Fine	45-75
Ultra Fine	2-45

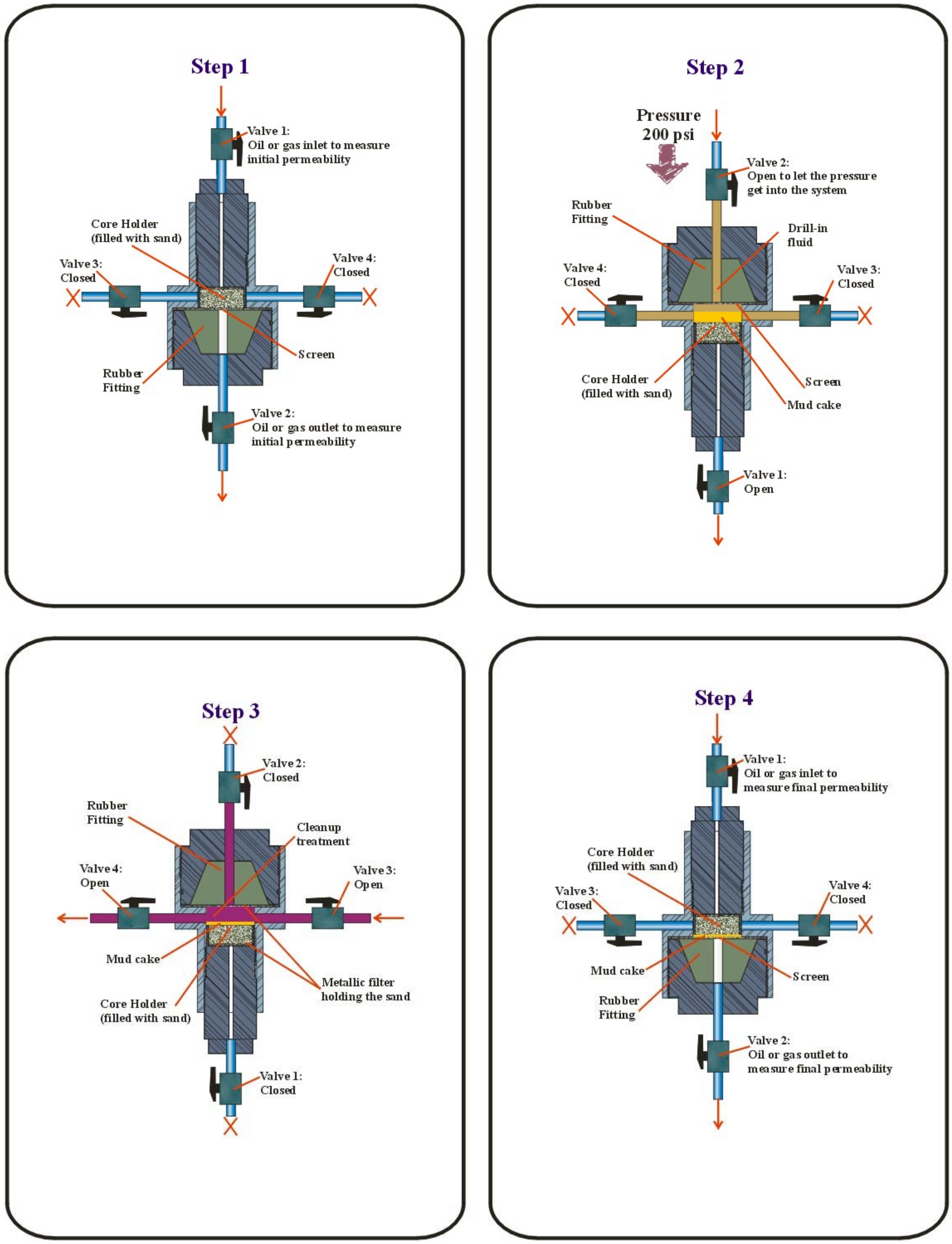


Fig. 3. Conoco Cell, Apparatus and Procedure

Particle Size Distribution Analysis for Sized Salt Drill-in Fluid

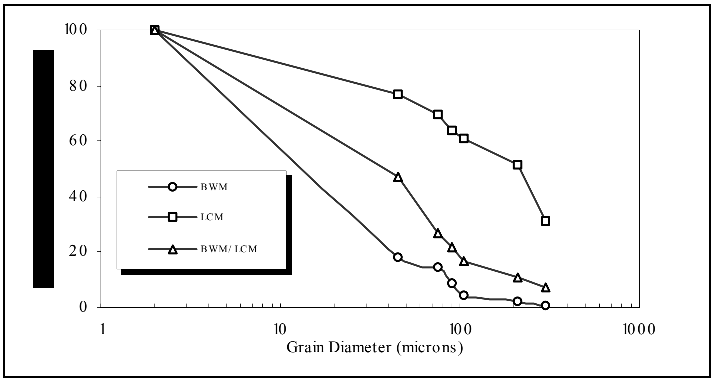


Fig. 4– Particle size distribution of BWM and LCM of SS DIF

Fig. 4 shows the PSD of the sized-salt BWM and LCM. The median particle sizes (D_{50}) for bridging, weighting, fluid-loss control materials and their mixture were determined to be 11 μm, 230 μm, and 38 μm, respectively. It should be pointed out that the BWM constitutes a high proportion of the solids that form the SS DIF, which provides most of the main characteristics of the filtercake. Table 3 summarizes the size range classification for SS solid materials. A comparison between the ultrafine amount in these two ingredients of the SS DIF indicated that the BWM provides the highest value of the damaging size range (82%). However, in mixture with the LCM, this value decreased to 53%.

Table 3 - Size range classification for BWM and LCM of SS DIF and their mixture

Classification	BWM	LCM	Mixture
Medium	13.5	38.6	20.0
Fine	4.1	7.4	20.0
Ultra Fine	81.6	22.8	52.8

Fig 5 depicts the performance of the PSD of the BWM and LCM for the SS DIF with clay. The PSD did not change significantly when clay was added at 2.5% and 5% wt, and additionally it can be observed that the median grain size was slightly diminished from 38 μm to 35 μm. Table 4 summarizes the size range classification for BWM and LCM with clay mixture

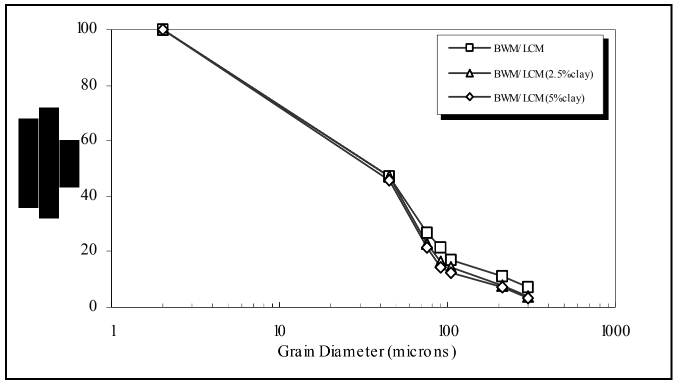


Fig. 5 – Particle size distribution of BWM and LCM of SS DIF plus clay

Table 4 - Size range classification for BWM and LCM of SS DIF with clay			
Classification	Percentage (0% clay)	Percentage (2.5% clay)	Percentage (5 % clay)
Medium	20.0	19.1	18.4
Fine	20.0	24.5	24.0
Ultrafine	52.8	52.6	54.4

Table 5 - Size range classification for BWM and LCM of SS DIF with 75-µm sand mixture			
Classification	Percentage (0% 75-µm sand)	Percentage (2.5% 75-µm sand)	Percentage (5% 75-µm sand)
Medium	20.0	18.9	35.5
Fine	20.0	32.6	23.4
Ultrafine	52.8	42.9	36.4

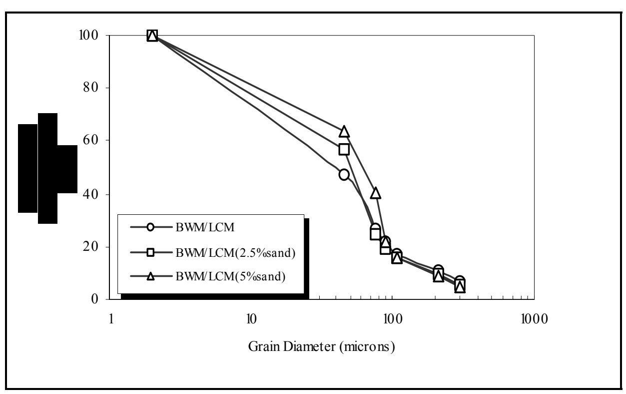


Fig. 6 – Particle size distribution of BWM and LCM of SS DIF plus 75- µm sand

The PSD of the solid materials of the SS DIF with 75-µm sand is shown in Fig.6. A significant decrease in ultrafine content is noticeable, and the median size of the particle grains increased. The median size varied from 38 µm to 50 and 58 µm when the 2.5 %

and 5% of 75-μm sand were added to the DIF. Table 5 summarizes the size range classification for SS DIF components and 75-μm sand. Here, the ultrafine content changed when sand was added to the solid materials of the SS DIF. The percentages decreased from 53% to 43% and 36% with an increase of 75-μm sand of 2.5% and 5%, respectively.

<u>Particle Size Distribution Analysis for Sized Calcium Carbonate Drill-in Fluid</u>

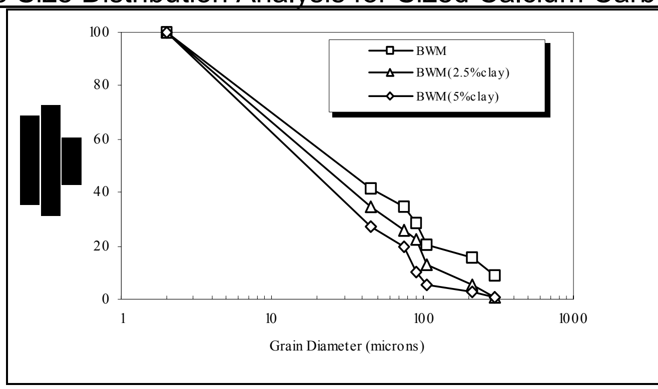


Fig. 7 – Particle size distribution of BWM of SCC DIF plus clay

Fig. 7 shows the PSD for BWM in the SCC DIF and clay mixture. Percentages of 2.5% or 5% clay were mixed with the SCC weighting and bridging agent to observe the performance of combined average PSD. The median size (D_{50}) decreased from 28 μm to 20 μm and 18 μm for 2.5% and 5% clay, respectively. Table 6 depicts the percentages calculated for every size range in this sample. It shows BWM of SSC has a high content of ultrafine material (58%), which was increased by adding clay to 65% and 73% for 2.5 and 5%, respectively.

Table 6 - Size range classification for BWM of SCC DIF and clay mixture

Classification	Percentage (0% clay)	Percentage (2.5% clay)	Percentage (5% clay)
Medium	26.4	24.9	19.3
Fine	6.3	9.0	7.2
Ultrafine	57.8	65.3	72.8

Fig. 8 shows the behavior of the PSD when 2.5 and 5% wt of 75-μm sand was added to BWM of SCC. Notice that an inflection point at 75 μm occurred, producing a reduction in ultrafine content. For 2.5% wt of sand, the median grain size was increased from the original 28 μm to 42

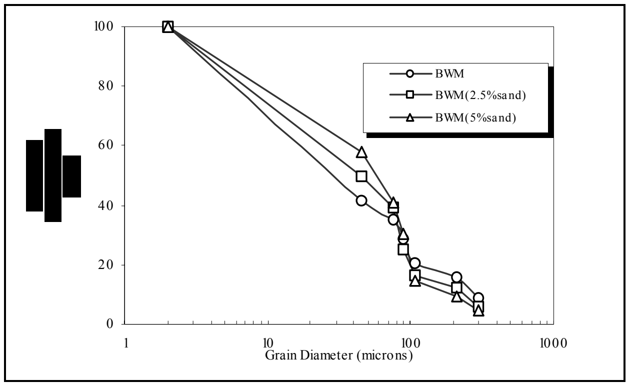


Fig. 8 – Particle size distribution of BWM of SCC DIF plus 75-µm sand

µm, and when the percentage of sand was increased to 5%, the average grain size increased from the original 28 µm to 52 µm. Table 7 summarizes the size range classifications for BWM of SCC and 75-µm sand. The ultrafine material showed a decrease when 75-µm sand was added to the BWM; the original percentage was changed from 58% to 50% for 2.5% sand and to 42% for 5% sand.

Table 7 - Size range classification for BWM of SCC DIF with 75-µm sand mixture

Classification	Percentage (0% 75-µm sand)	Percentage (2.5% 75-µm sand)	Percentage (5% 75-µm sand)
Medium	26.4	33.3	36.5
Fine	6.3	10.7	16.8
Ultrafine	57.8	50.0	42.3

From the previous results, it is evident that the weighting and bridging agents make up a significant fraction of the DIF and even more of the filtercake. The PSD of the solid material of the filtercake shows that the SCC weighting material has an average grain size of 28 µm and a high percentage of ultrafine particles, 58%. Therefore, the DIF would tend to form a thick, impermeable filtercake because of the tighter packing of these small particles. Addition of clay to the SCC DIF would increase the ultrafine material content in the filtercake; thus, it will develop a tighter and harder filtercake than the one formed by the original SCC DIF with 0% drill solids. In contrast, the filtercake formed by SCC with 75-µm sand added, the median grain size will be slightly increased and the ultrafine content substantially diminished. This filtercake will be much more permeable and less tight and hard.

The SS DIF may develop a more permeable and weaker filtercake because of its relatively large median size (38 µm) and relatively small percentage of ultrafine particles (53%). However, the presence of clay in the filtercake developed by SS increases the cohesive force among particles, producing a filtercake stronger than the one developed by the original SS DIF with 0% drill solids. The filtercake containing 75-µm sand would have larger permeability and decrease the cohesive force among particles because of the coarse sand particles.

The PSD of the filtercake depends on the PSD of the DIF solids; the finer the original size, the closer the particles will be packed. Under the same differential pressure, ultrafine particles tend to result in maximum packing of the particles, resulting in a filtercake with lower permeability and porosity than its coarse counterpart. Finally, the wider particle size distribution of the clay has a larger effect on the PSD of the DIF solid components than mono-sized sand as solids. The more mono-sized the particle distribution, the higher the median size of the particles in the DIF solids and the lower the ultrafine material content.

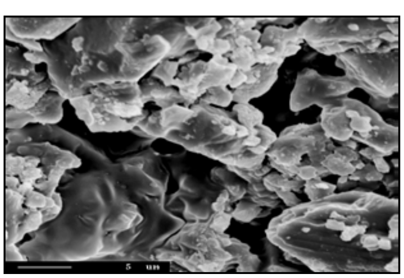
Cake Texture Imaging

A scanning electron microscope was used to study the original cake texture developed by the SCC and SS DIF's. The filtercakes developed by these two DIF's with 5% simulated drill solids (clay or 75-μm sand) were observed as well. The microscopic structure of the DIF filtercakes built up under static conditions was observed with a Cameca SX-50 electron microprobe. The surface and cross- sectional areas of filtercakes were imaged, and the working magnification ranged from 100X to 4,000X.

These observations were carried out so as to obtain a better understanding of the microscopic structure of the filtercakes, the effect of the different additives, and the variations of the cake structures versus the presence of simulated drill solids. One of the most important characteristics to observe under the microscope is the distribution of the ultrafine and fine particles with size less than 45 μm that are retained by the network consisting mainly of larger particles. An important feature to be considered during qualitative observations of the filtercakes is the distribution and size of the pore throats, which restrict the flow of the brine or acid during the cleanup phase of these filtercakes.

Sized-Calcium Carbonate Filtercake Texture

The SCC's BWM has the widest range of particles less than 45 μm (58%). The starches and biopolymers that are incorporated as solid material to control fluid loss in these DIF's hold these calcium carbonate particles together. This suggests that the SCC DIF can develop a low-permeability filtercake (0.08 md), which has been confirmed by the observations of its filtercake structure. The images of the SCC filtercake show a network of rigid particles of calcium carbonate ($CaCO_3$) characterized by small pore sizes. Fig. 9 illustrates the surface of this filtercake, demonstrating its unique cake structure.



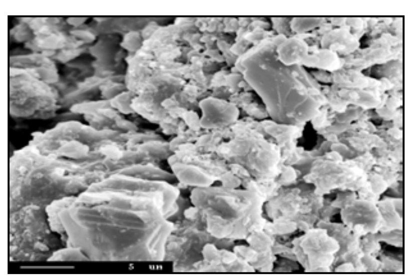


Fig. 9 – Texture of filtercake surface of SCC 2,500X. Fig. 10 – Texture of filtercake surface of SCC and clay-2,500X

The filtercake developed by a mixture of SCC DIF and clay is shown through (Fig 10). This filtercake appears to be much more clustered together and the pore throats are visibly filled with ultrafine material. This filtercake has a structure similar to that observed in the original filtercake (0% drill solids), but the size of the pores was smaller. The structure of this filtercake suggests that the permeability and the pore throat sizes of the SCC filtercake could be severely reduced by the addition of clay.

A comparison between Figs. 9 and 10, original filtercake (0% drill solids) and filtercake including 5% clay shows the effect of the ultrafine materials. Here, the latter is a calcium carbonate network with the interstitial space filled with ultrafine material, consisting mainly of particles smaller than 5 μm which seem to have reduced the connection among the pore throats because the particles were packed closer together.

The filtercake formed by SCC DIF with 5% 75-μm sand is shown in (Fig. 11). In general, the 75-μm sand as solids constitute a mono-sized particle distribution and the degree of infilled pores among the filtercake particles is relatively low, and high filtercake permeability is produced. In Fig. 11 clustered grains of ultrafine material form some bridges, which are embedded into the $CaCO_3$ network. Here, the pore size is bigger than

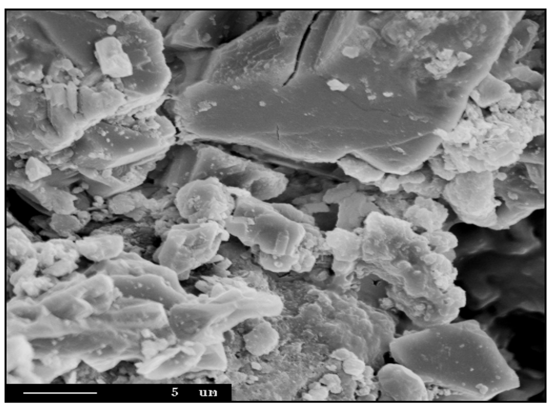


Fig. 11 – Texture of filtercake surface of SCC and sand-2,500X

that formed by SCC filtercakes with clay. Furthermore, the filtercake with 75-μm sand resembles that developed by the original SCC one developed by SCC DIF containing clay. This can be explained in terms of the decreasing ultrafine particle-size distribution that substantially increases the content of medium- and fine-size particles.

Apparently, the filtercake developed by SCC DIF containing 75-μm sand retains better pore throat connection than the Sized-Salt Filtercake Texture.

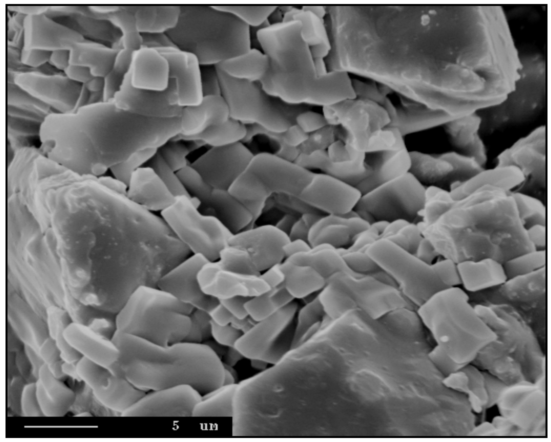


Fig. 12 – Texture of filtercake surface of SS-2,500X

Fig. 12 is a close-up image of individual pore throats of the SS filtercake; there is also shown how the pores are bridged with a mixture of ultrafine BWM with sizes less than 5 µm. Also, polymer additives rigidly hold the BWM together, xanthan gum and starches The comparative SEM images of the filtercake formed by SS with and without drill solids were also investigated. The filtercake imaging of the original SS DIF shows that the SS filtercake is quite different from that of the SCC. In the SS filtercake, (Fig. 12) is shown how large particles of LCM with sizes varying from 20 µm to 80 µm are in grain-to-grain contact and the pore structure is controlled by ultrafine particles of BWM that constitute about 60% of the solid material of the filtercake. As mentioned before, the SS BWM is a mixture of xanthan gum, starches, and sized sodium chloride with a high ultrafine content (82%) and an average median grain of 11 µm.

On (Fig. 13) we can see an image of the filtercake developed by SS containing 5% clay. The clay has occluded pore throats of the filtercake. A thorough inspection of the filtercake with SEM showed similar results throughout the sample. The structure observed in the SS/clay filtercake seems to indicate that the behavior of calcium montmorillonite was affected by the ions of sodium and chloride present in the suspension of the DIF before the filtercake was formed. The flocculated clay is trapped into the framework of the SS particles, forming clusters in lumps. The appearance of the pore-lining flocculated clay is very different from that before addition to the SS DIF.

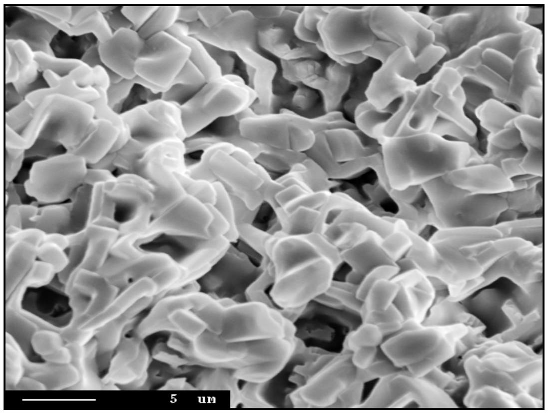


Fig. 13 – Texture of filtercake surface of SS and clay-2,500 X

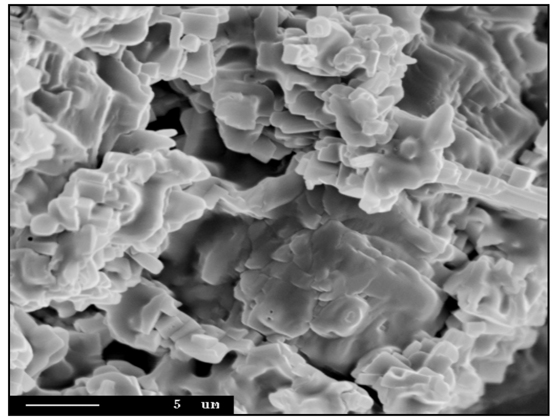


Fig. 14 – Texture of filtercake surface of SS and sand–2,500X

The texture of the BWM grains in (Fig. 13) indicates that they have been partially dissolved; the BWM grains in (Fig. 12) shows relatively little dissolution. This may be simply an artifact of the drying process prior to filtercake examination or it may perhaps be related to water from the flocculated clay during filtercake formation.

Fig. 13 shows that big grains are in contact and the pores are filled with a mixture of ultrafine material that appears to be a mixture of BWM and flocculated clay. Ultimately, this filtercake is a LCM network whose median size is 230µm with the interstitial spaces filled by BWM and flocculated clay. The thick film formed over the grains and pores produce a filtercake with high cohesive force among particles.

The medium and small particles of flocculated clay in Fig. 14 can readily bridge to form this filtercake and plug its pores more strongly than the uniform small particles of its weighting and bridging agents. All samples show well-interconnected intergranular pores with occurrences of particles less than 5 µm.

Fig. 14 depicts the filtercake developed by SS and 75-µm sand as drill solids. Both photographs show that the sand grains are accommodated within the network formed by small particles of BWM.

Fig. 14 shows that the filtercake with 75-µm sand is more chaotic and clustered than for the cakes formed by the previous SS systems. This appears to be caused by many small weighting and bridging particles that are perpendicular to larger LCM and medium sand particles. This structure seems to have a larger contact area than the other filtercake structures because the sand grains were embedded among particles.

Effect of Screen Plugging Caused by Backflowing Filtercake

The primary objective of these laboratory tests was to investigate the mechanism when a whole or residual filtercake with drill solids developed opposite an unconsolidated sandstone core is sandwiched between the core face and the sand-control metallic screen. The tests focused on various responses of the filtercakes developed by the DIF's containing drill solids when they are either physically or chemically removed from the core.

To build up the filtercakes, either original SCC or original SS DIF's were mixed with a predetermined amount of drill solids (2.5% and 5%) and then displaced for two hours at 150°F. To evaluate the integrity of the filtercake, metallic screens with slot widths of 125 μm and 250 μm were used to emulate the backflow through screens. Brine of 3% wt KCl was displaced to wash the filtercake. Afterwards, backflow was performed by displacement of oil (Soltrol-170) in the production direction. Two stages in this cleanup process were observed: First, the external filtercake formed by the tested DIF's could not be effectively removed by KCl brine and second, the residual filtercake could be dislodged from the core simply by application of backpressure.

The results derived from the regained permeability obtained after 3% KCl cleanup and subsequent backflow are illustrated and discussed in the following sections

Sized-Calcium Carbonate Filtercake Performances

The results of a detailed evaluation of the effects of the filtercake developed by SCC DIF are shown in Figs. 15 and 16. These plots show the regained-flow capacity for the core/screen system. The vertical axes represent the regained-flow capacity (k_r/k_i) profile and the horizontal axes represent concentration of the drill solids, median size of the particles, and percentage of the ultrafine content present in the DIF. Here, k_r is the restored permeability after potassium chloride brine (KCl) displacement, and k_i is the initial undamaged permeability before DIF circulation.

Fig. 15 shows the behavior when backflow was imposed through the original SCC (0% drill solids) filtercake. When a screen-slot width of 125 μm was used, the regained-flow capacity was as high as 42%. When the clay concentration was increased to 2.5%, the regained-flow capacity decreased to 10.6%, whereas an increase to 5% clay reduced the regained-flow capacity to 3.2%.

After the screen slot width was changed to 250 μm, new tests were carried out including backflow through the residual filtercakes. A reduction in flow capacity of 22% was observed when the original SCC formed the filtercake. When 2.5% clay was added, the regained-flow capacity decreased to 10.4%, whereas an increase of 5% clay reduced the regained-flow capacity to 4.9%

A simple inspection of (Fig. 36) reveals a common characteristic between the behavior of the filtercake on the two screens. The reduction of regained-flow capacity is directly related with an increase of the suspended drill solids forming the filtercake. As shown on the horizontal axis, the presence of clay increases the content of ultrafine particles and decreases the median size of the particles, which makes the filtercake tight, compact, and hard to remove from the core.

The performance observed with the different SCC filtercakes when they are back flowed through 125-µm and 250-µm screens can be explained in terms of the retention capacity of those screens, which is basically a function of the relationship between particle size and screen-slot widths. The screen is supposed to retain particles larger than its slot width, but small particles can get through and plug the internal wraps of the screen.

During the backflow, the SCC filtercakes both with and without clay are detached from the core completely as a consequence of the backpressure, then the filtercake is totally or partially forced through the screen slots. On the basis of the dry PSD obtained from the SCC with clay solids, the plugging tendency can be associated with the amount of particles allowed to get through and form bridges in the middle and inner layers of the screen. The main purpose now is to use the 125-µm and 250-µm screens in Fig. 14 and interpolates each cumulative percentage of particles to be retained. Metallic screens are designed so that the internal wraps have decreasing slot widths that can retain particles smaller than the nominal slot width. This design allows internal accumulation of solids with a specific size of particles, increasing the likelihood of plugging. For the following set of experiments, 2.5% and 5% wt 75-µm sand were added as drill solids to the SCC DIF. Fig. 16 shows the regained-flow capacity obtained using 125-µm and 250-µm screens.

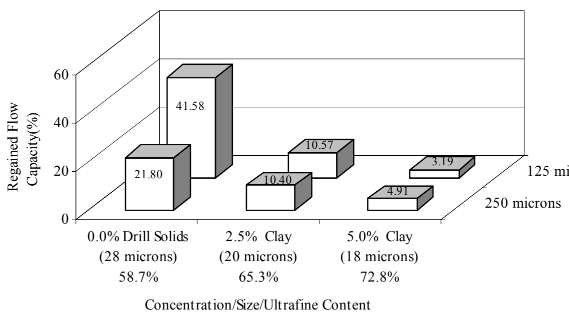


Fig. 15 – Regained-flow capacity behavior of SCC plus clay after 3% KCl cleanup

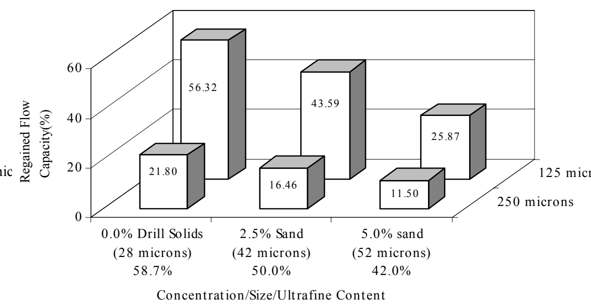


Fig. 16 – Regained-flow capacity behavior of SCC plus sand after 3% KCl cleanup

The chart shows that the regained-flow capacity was highest when the original SCC was displaced. Afterwards, there is a significant decrease in regained-flow capacity as a consequence of increasing sand concentration. Using the 125-µm screen, the regained-flow capacity when 75-µm sand was added to the SCC DIF at 2.5% and 5% was 43.6% and 25.9%, respectively.The regained-flow capacity profile showed a reduction for the 250-µm screen when 2.5% and 5% 75-µm sand were added to SCC DIF. The regained-flow capacity was 16.6% and 11.5 %, respectively. Again, the plugging tendency is associated with the amount of particles allowed to get through and form bridges in the middle and inner layers of the screen. The values of cumulative percentage were interpolated from Fig. 6 for both 125-µm and 250-µm screens.The presence of 75-µm sand decreased the ultrafine sizes in the BWM for SCC, but the median size of the particles was substantially increased. These changes made the filtercake more permeable, weaker, and easier to be removed under backpressure than SCC filtercakes affected by clay.

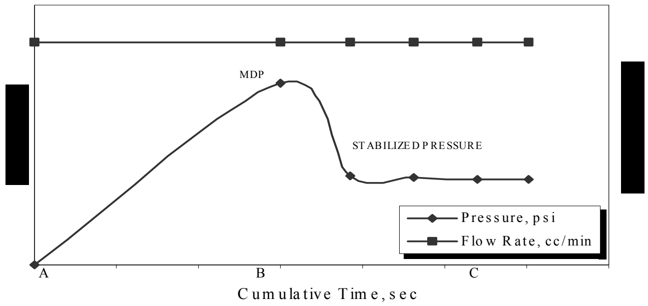
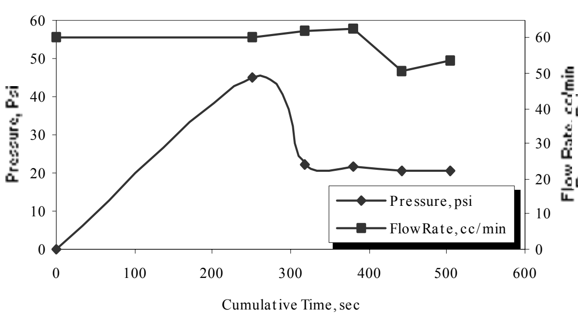


Fig. 17 – Generalized pressure behavior during filtercake backflow

Fig. 17 shows the general shape displayed by the pressure and flow rate versus time when oil (Soltrol-170^{TM}) is displaced through the core/filtercake/screen, as observed in the laboratory tests. Notice the flow rate was kept at a constant value of 60 cc/min.
Between times A and B, the pressure (minimum dislodging pressure or MDP) builds up before the cake detaches from the core. At time B, the pressure has grown to a value high enough for the filtercake to dislodge from the unconsolidated core and fall down over the screen. At this point the filtercake is squeezed against the screen, plugging some of the slots and allowing some remaining DIF and oil to flow through it. At time C, flow continues and the pressure keeps decreasing until it reaches a stabilized pressure.

Figs. 19 and 20 depict the MDP behavior of the SCC/clay filtercakes. It can be observed that the MDP was substantially increased when clay content was increased.



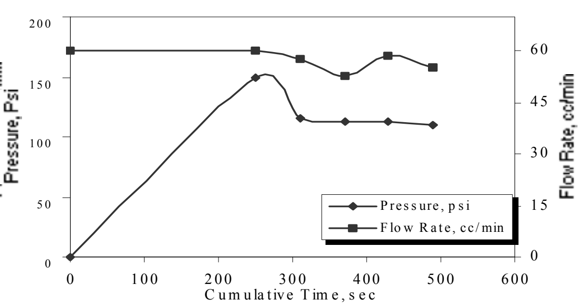


Fig. 19 – Filtercake backflow pressure of SCC plus 2.5 % clay

Fig. 20 – Filtercake backflow pressure of SCC plus 5 % clay

When sand as drill solids is added to the SCC DIF, a similar behavior is observed during the backflow (Figs. 21 and 22). Nonetheless, the numerical values of the MDP and stabilized pressure are much larger when clay is added to the DIF instead of sand as drill solids for the same concentration. This performance indicates that the SCC filtercake with sand has weak cohesion among particles, but the increase of coarser particles causes an increase of the MDP for this kind of filtercake, which increases the screen plugging, reducing the regained-flow capacity of the system (core/filtercake/screen). This is a characteristic of the DIF system.

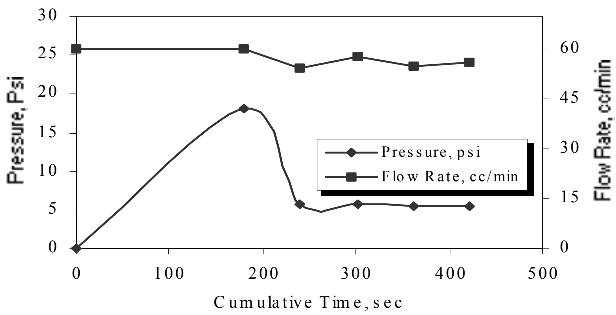


Fig. 21 – Filtercake backflow pressure of SCC plus 2.5 % sand

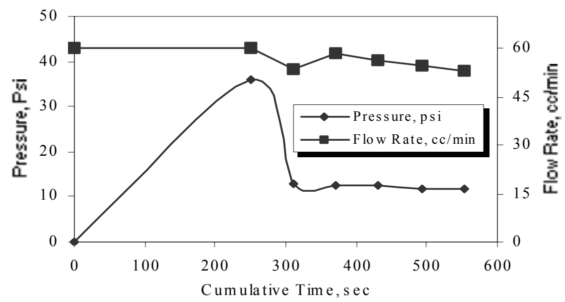
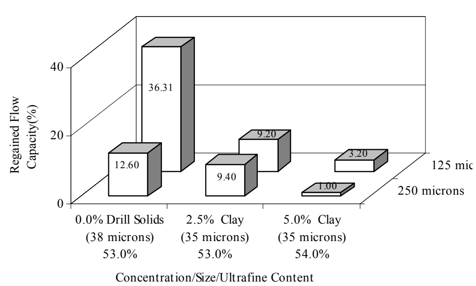


Fig. 22 – Filtercake backflow pressure behavior of SCC plus 5% sand

From these observations we can infer that the smaller the size and the higher the quantity of ultrafine material in the SCC filtercake, the harder it is to remove. High MDP's seem to be associated with SCC filtercakes with high ultrafine material content. This suggests that the SCC filtercakes with clay are rigid and develop strong cohesion among their particles, which increases the MDP values, increasing the screen plugging and causing the consequent reduction in the regained-flow capacity.

[redacted]

Sized-Salt Filtercake Performance



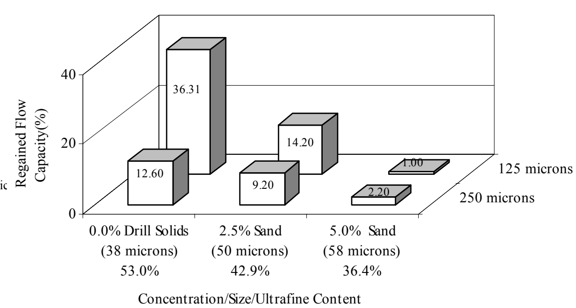


Figure 23, 24. The charts show comparative performance of different DIF systems.

The results of a detailed evaluation of the effects of the filtercake developed by SS DIF are shown in Figs. 23 and 24. The results obtained for the filtercake developed by the original SS and SS/clay are shown in Fig. 23. The values were determined to be about 36.3% and 12.6% for the 125-µm and 250-µm screens, respectively. During the backflow through the 125-µm screen, the regained-flow capacity profile obtained for the

SS/clay filtercake can be summarized as follows: For 2.5% clay, the regained-flow capacity decreased to 9.2%. An increment in percentage of clay to 5% produced a reduction in the regained-flow capacity to 3.2%. For the 250-µm screen and 2.5% of clay, the regained-flow capacity fell to 9.4%. An increase in the percentage of clay concentration to 5% caused a severe decrease in the regained-flow capacity to 1%. The values of the amount of solids to be retained by both 125-µm and 250-µm screens were interpolated from Fig. 6

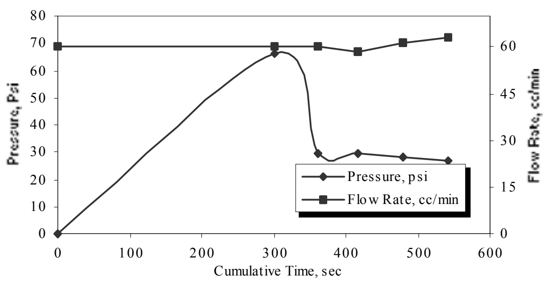


Fig. 23– Regained-flow capacity behavior of SS plus clay after 3% KCl cleanup

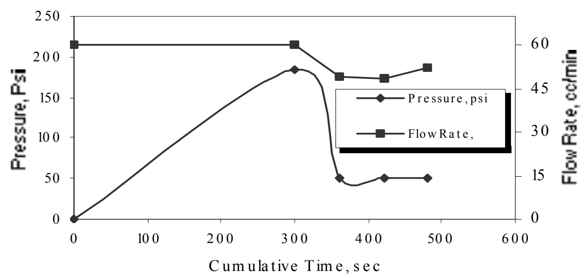
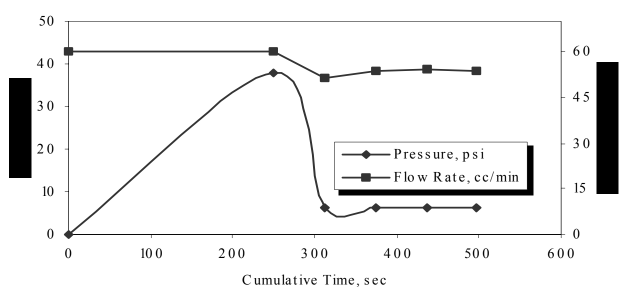


Fig. 24 – Regained-flow capacity behavior of SS plus sand after 3% KCl cleanup

The addition of 75-µm sand as drill solids to the SS DIF resulted in reduction of regained-flow capacity when the filtercake was under backpressure through a 125-µm and a 250-µm screen as shown in Fig. 11. When the percentage of sand was 2.5%, the regained-flow capacity was 14.2%. Sand percentage was increased to 5% and the regained-flow capacity decreased to 2%. With the 250-µm screen, the regained flow capacities were calculated to be 9% and 1% when the sand concentration varied from 2.5% to 5%, respectively.

Fig. 25 shows the pressure performance during the backflow through filtercakes developed by SS DIF systems with and without clay.



Figs. 25 shows the pressure performance during the backflow through filtercakes developed by SS DIF systems with and without clay.

During the backflow through the original SS filtercake, a high MDP pressure was required to detach the filtercake. This high pressure could be associated with a filtercake whose structure is controlled mainly by the presence of xanthan gum acting as glue on the graded salt particles. The presence of the xanthan gum could create a high adhesion between the filtercake and the core, increasing the strength of the filtercake to be removed from the core.

The presence of clay as drill solids greatly increased the MDP value as a result of an increase of the hardness of the filtercake caused by the presence of the flocculated clay into the filtercake. In the microscopic observations through this filtercake, it was observed that the flocculated clay was entangled among the BWM, which made the filtercake very strong, increasing the cohesive force among particles. Additionally, polymer intrusion must have occurred, making a strong adhesion between the filtercake and core and increasing the MDP to break down the filtercake. It is worth emphasizing that the presence of clay worsens the removal of the filtercake after 3% KCl treatments, increasing the MDP (and hence the plugging of the screen) and reducing the regained-flow capacity of the systems. The regained-flow capacity for SS filtercakes is lower than that for SCC filtercake.

Figs. 28 and 29 depict the behavior when the SS filtercake with 75-μm sand was backflowed. MDP increased as the concentration of sand increased in the filtercake. The imaging of this filtercake indicated that the sand as drill solids was embedded into the pore throats where it was held strongly by the glue formed by polymers and starches. Consequently, the cohesive force among SS filtercake particles was increased when sand made up the filtercake.

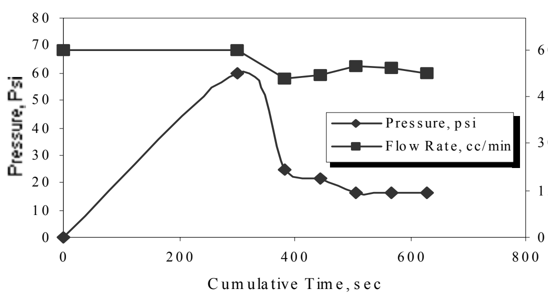


Fig. 28 – Filtercake backflow pressure behavior of SS plus 2.5% sand

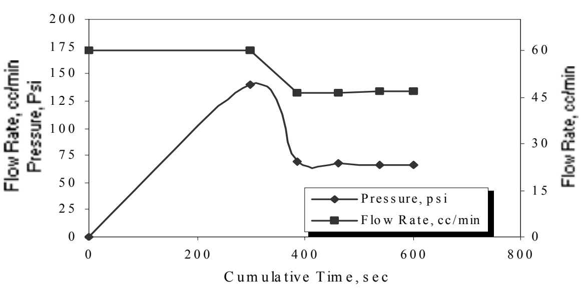


Fig. 29 – Filtercake backflow pressure behavior of SS plus 5% sand

A comparison between SCC filtercakes and SS filtercakes indicated that the filtercakes developed by SS DIF's are affected by the presence of xanthan gum, which seems to increase the strength of the filtercake since the particles of salt and gum show tenacious cohesion. Therefore, the SS filtercakes are harder to remove from the core during backflow than their counterpart SCC filtercakes. Additionally, when a clay drill solid is a type of calcium montmorillonite, there is a base exchange from a calcium base to a sodium base clay.[17] The reduced repulsive charge between sheets and the high repulsive negative charge of the ionic atmosphere force the clay to collapse and the clay platelets form aggregates.

A comparison between the MDP's recorded during the backflow of the SCC and SS filtercakes suggests that SS filtercakes are more stable and resistant to breakup than SCC filtercakes. The MDP reached during the backflow was generally lower in systems (core/filtercake/screen) of SCC DIF than of SS DIF. The regained permeability calculated for the system also was better for the SCC filtercake than for the SS filtercake.

Screen Permeability Impairment

The impairment of screen permeability was established by determining the flow characteristic of the screens before and after backflow of the filtercake. Two approaches were used to verify the screen-plugging mechanism. The following section describes the results.

A standard lubricating oil (SAE 30) was first circulated through the PoroplusTM metallic disks at 60 cm/min to establish the initial flow characteristics. Afterwards, either original SCC or SS were used to build up filtercake. Then, the core/filtercake/ screen system was backflowed using Soltrol-170TM. Once the screens were plugged and the unconsolidated core removed from the linear cell, SAE 30 oil was flowed through the filtercake/screen, and the flow rate and pressure were determined to evaluate the residual flow characteristics after screen plugging.

Fig. 30 shows the performance of the screen permeability with and without plugging. The metallic screen's initial permeabilities were determined to be 5,092 D for 125-µm screen and 4,160 D for 250-µm screen. Some variability in the permeability can be seen in the cases where the filtercakes were pushed into the screen slots by the high backpressures applied to displace the Soltrol through the core/filtercake.

As the screens retained the filtercake particles, their permeabilities were reduced. The permeabilities of the 125-µm screen after backflowing original SCC and SS filtercakes were reduced to 3,000 and 2,700 D, respectively. For 250-µm, the reductions in permeabilities were calculated to 2,800 and 1,700 D, respectively, when SCC and SS filtercakes were backflowed.

The screen behavior at the original SCC and SS filtercakes suggests that screen permeability was affected more severely by the SS filtercakes than by those with SCC. Additionally, the metallic screens allowed ultrafine particles from the filtercake to invade deeply as high MDP was applied. These phenomena are in good agreement with those observed in the previous tests.

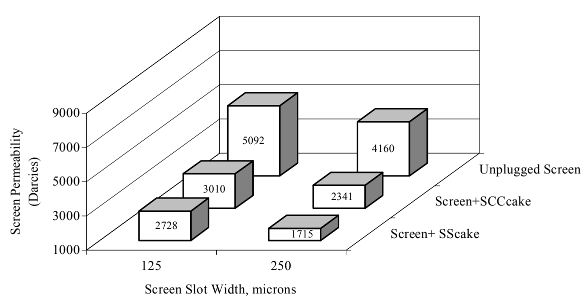


Fig.30– **Screen permeability performance**

Cleanup of Filtercake by Acidizing with 5% Hydrochloric Acid

The filtercake formed over the unconsolidated core or on the metallic screen can be highly impermeable because of its ultrafine material content. It has been demonstrated that ineffective removal occurs during the 3% KCl treatment and following backflow. Thereupon, some percentage of chemical agents (acids) may be necessary to remove the filtercake before production.

Cleanup of Sized-Calcium Carbonate Filtercake

The first set of experiments was done by displacing 5% HCl acid over the filtercakes built up using SCC DIF containing clay. The results for the SCC filtercake are shown in Figs. 31 and 32. Figure 31 shows that the 5% HCl treatment provided a cleanup efficiency at 150°F and 190°F ranging from 45.4% to 93.3% when the original SCC developed the filtercake. At 150°F, the filtercakes including 2.5% and 5% clay showed 20% and 12% in the regained flow capacities after the cleanup. At 190°F and the same clay concentrations, the regained permeabilities were about 30%.According to the data, the 5% HCl produced a restoration in regained permeability related directly with the increase of temperature. An incremental content of clay in the SCC DIF affected its filtercake removal.

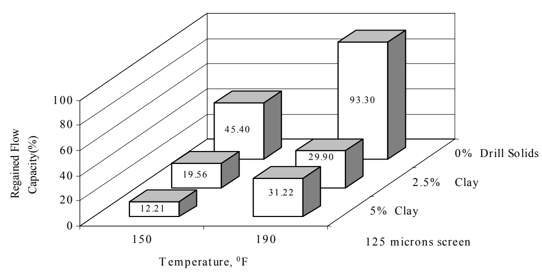


Fig. 31 – Regained-flow capacity behavior of SCC plus clay after 5% HCl cleanup

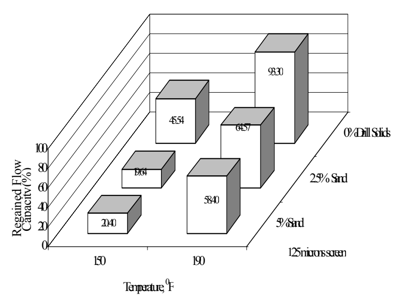


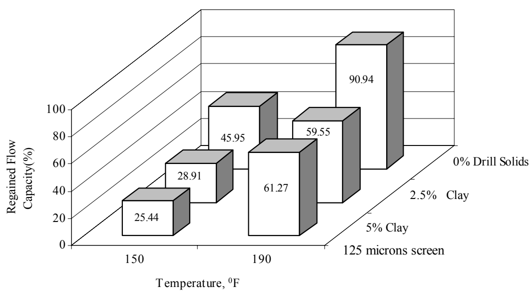
Fig. 32 – Regained-flow capacity behavior of SCC plus sand after 5% HCl cleanup

Figure 32 shows the results of filtercake removal testing on the SCC DIF filtercake containing 75-µm sand. At 150°F the 5% HCl was observed to provide an average regained-flow capacity of 20% when 2.5% or 5% of sand was added to the DIF. At 190°F, the regained-flow capacity was restored to 65% and 58% when 75-µm sand was added to the DIF at 2.5% and 5%, respectively. These tests indicated that 5% HCl seems to perform at high efficiency in the cleanup if the concentration of 75-µm sand is low at higher temperatures.

Another important observation of regained-flow capacity performance is related to the type of the drill solids. SCC/clay filtercakes have lower regained-flow capacity than those with 75-µm sand. The former has low interconnection among its pore throats, which prevents the acid from penetrating into the filtercake to reach total dissolution of the calcium carbonate, whereas the latter filtercake has much better connection among its pore throats, favoring the action of the acid. The chemical composition of the filtercake has a marked influence on the performance of cleanup when HCl is used to degrade the filtercake. The SCC filtercake is a concentration of solids dominated by calcium carbonate that is highly soluble in HCl. This solubility is improved when the temperature of the reaction is increased

Cleanup of Sized-Salt Filtercake

Figure 33 shows that for the original SS, the 5% HCl restored the regained flow capacities to 45.6% at 150oF and to 91% at 190°F. The regained-flow capacity profile obtained at 150°F for the SS/clay filtercakes can be summarized as follows: For 2.5% clay, the regained-flow capacity was restored to 29%. For 5% clay the restoration in regained-flow capacity was 25%.



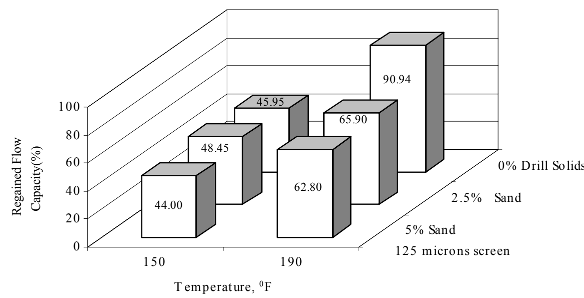


Fig. 33 – Regained-flow capacity behavior of SS plus clay after 5% HCl cleanup

Fig 34 – Regained-flow capacity behavior of SS plus sand after 5% HCl cleanup

At 190 F and 2.5% clay, flow capacity was restored to 60%. With 5% clay the restoration in regained-flow capacity was 61%. The results for SS DIF with 75-µm sand are shown in Fig. 34. For the filtercake with 2.5% and 5% sand, the regained permeability after cleanup at 150oF was 48% and 44%, respectively. When the temperature was increased to 190oF, the cleanup ranged from 66% to 63%.

The cleanup behavior for the original SS filtercake is similar to that for original SCC. Likewise, when the temperature was increased, the effectiveness of 5% HCl to remove the filtercake was to a large extent increased. The apparent high level of regained flow capacities for SS blended with drill solids either clay or 75-µm sand was probably caused by the relatively high proportion of coarse material in the filtercake itself, which creates good pore throats that favor the displacement of the acid. The relatively low values of regained permeability for SS/clay filtercakes could be attributed to the inaccessibility of salt particles covered by unbroken polymer and non-degrading flocculated clay particles. A visible restoration of flow capacity was attained when the temperature increased. The SS/75-µm sand filtercake cleanup was significantly improved by the 5% HCl treatment. This suggests that the high connection of the pore throats in the filtercake favor the acid reaction with the polymer, not only causing reaction with them but also dissolving the saturated SS particles. The acid probably dissolved the SS after reacting with the polymer coating, which is constituted mainly by xanthan gum. Xanthan dissolves in many acidic solutions, even in strong acids such as 5% sulfuric acid, 5% nitric acid, 10% hydrochloric acid.28 The efficiency of 5% HCl to degrade the SS/sand filtercakes was increased with temperature.

Cleanup of Sized-Calcium Carbonate Filtercake

The 15% HCl rapidly increased the flow capacity of both the original SCC filtercakes and filtercakes including drill solids. The 15% HCl increased the regained-flow capacity sharply to a level where it behaved as if there were no filtercake as the acid reacted with the starches and the total dissolution of BWM. The effects of increasing HCl concentration in restoring the regained-flow capacity at two different temperatures for SCC filtercakes are shown in Figs. 35 and 36. These charts depict the performance of the SCC with and without drill solids. Figure 35 shows that the regained flow capacities after 15% HCl cleanup at 150^{o} F and 190^{0} F increase considerably in comparison to the values obtained with the 5% HCl treatment. The three regained flow capacities were 83, 71, and 64% at 150^{o}F. These values indicate that the cleanup decreases when clay made up the filtercake. The calculated values at 190^{o}F were 99, 80, and 72%, indicating that the cleanup was considerably improved, regardless of the clay concentration.

A similar behavior for 75-µm sand/SCC filtercakes is shown in Fig. 36. The regained flow capacities at 150^{o}F for 2.5 and 5% sand were averaged to 79%, whereas at 190^{o}F the values were 97% and 90%. There is little difference after cleanup for each SCC/sand filtercake. All regained flow capacities are close to the initial values. A volume of 1 cc of 15% HCl acid can dissolve[26] 0.222 gm of $CaCO_3$. Thus 200 cc of HCl could dissolve 44 gm of the 63.6 gm that constituted the initial BWM for SCC DIF..

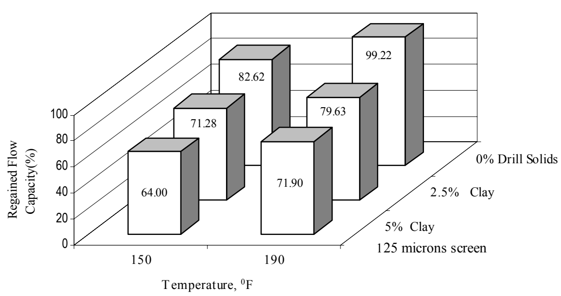


Fig. 35 – Regained-flow capacity behavior of SCC plus clay after 15% HCl cleanup

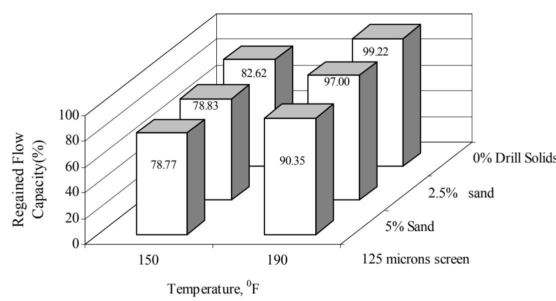


Fig. 36 – Regained-flow capacity behavior of SCC plus sand after 15% HCl cleanup

The reaction rate of HCl on $CaCO_3$ is accelerated especially at higher temperatures, the most important factor in improving the cleanup treatment with 15% HCl. According to the data, the HCl acid works to clean up the filtercakes efficiently at high temperatures and high concentrations. Nonetheless, the cleanup decreases when the concentration of drill solids increases in the filtercake. The drill solids (clay and sand) are not reactive with HCl, but the residual drill solids can be backflowed once the BWM is dissolved totally.

Cleanup of Sized-Salt Filtercake

The results for SS filtercakes are shown in Figs. 37 and 38. Again the overall regained flow capacities are relatively high when 15% HCl was used to degrade the filtercakes. Fig. 37 shows the regained-flow capacity profiles for SS/75-μm sand filtercakes. The filtercakes with sand showed a relatively high regained-flow capacity. For 150oF, the value was calculated to be 89% and 86% when the 75-μm sand concentration was varied from 2.5% to 5%. For 190oF, these calculated were 92% and 98%. The performance of the SS filtercake suggests that polymeric degradation took place when the HCl acted on the SS filtercake, and the remaining acid dissolved the released SS particles. A good dissolution of the SS filtercake is achieved by 15% acid. However, as already mentioned, it seems that the acid effectively attacks the filtercake by degrading the xanthan gum. After effective degradation of the polymeric part, 27 the remaining acid dissolves the soluble BWM and LCM. The drill solid particles released from the filtercake after dissolution of the graded salt are insoluble in HCl, and their residual can be produced during the backflow.

Figure 38 shows the profile for the regained-flow capacities for the SS/clay filtercakes. The regained-flow capacity averaged 82% for the original SS and 79% for 2.5% and 5% clay at 150^{o}F. The regained-flow capacity values (93, 89 and 87%) were significantly improved when the temperature was increased to 190^{o}F. The regained-flow capacities obtained after cleaning up the SS/clay filtercakes are higher than those obtained for SCC/clay. Again, the filtercake pore throat distribution provides better cleanup in the former than in the latter. Additionally, the chemical composition of the SS seems to help the BWM dissolution increase the regained flow capacities when the filtercake is deposited on the unconsolidated core.

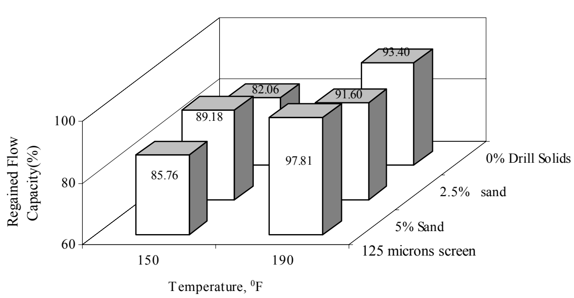


Fig. 37– Regained-flow capacity behavior of SS plus clay after 15% cleanup

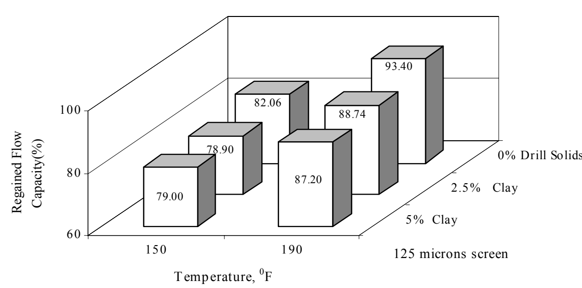
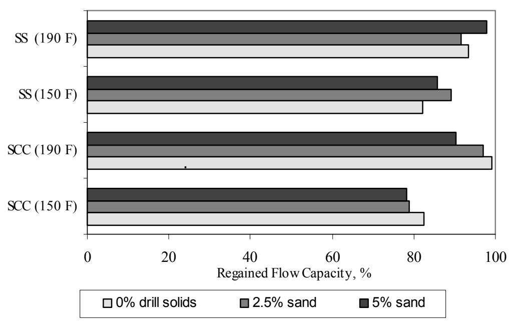


Fig. 38 – Regained-flow capacity behavior of SS plus sand after 15% HCl cleanup

Ultimately, the acid removed the bulk of the external and internal filtercake leaving the unconsolidated core face unstable. During the backflow, the unconsolidated sandstone could be produced after 15% HCl treatment, introducing experimental errors that would give unrealistically high values of cleanup. Figures 39 and 40 show a comparison between regained flow capacity profile of SCC and SS filtercakes containing clay or sand after treatment with 15% HCl. The charts indicate that SS filtercakes containing clay or sand are more soluble in HCl than those formed by SCC containing the same drill solids. The solubility has been substantially increased with high HCl acid concentration and temperature.



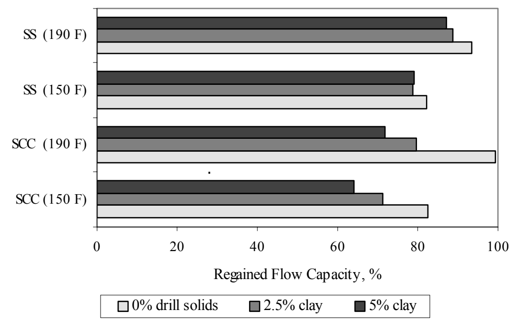


Fig. 39 – Regained flow capacity profile of SCC and SS filtercakes plus clay after 15% HCl treatment

Fig. 40 – Regained flow capacity profile of SCC and SS filtercakes plus sand after 15% HCl treatment

CHAPTER 3

Laboratory Tests, Statistical Analysis and Correlations

In this chapter, we have attempted to describe in detail our statistical treatment of the data, so that our conclusions can be fully supported. We developed multiple linear regression models to fit the physical properties of the drill-in fluids under the cleanup treatments, and used statistical analysis software to carry out the statistical analyses. We selected variables, transformed variables, forming models, and diagnosed models to develop the regression models. The general linear model for the multiple regression that relates a dependent variable to a set of quantitative independent variables is as follows:

$$y = \beta_0 + \beta_1 x_1 + \beta_2 x_2 + \ldots + \beta_k x_k + \varepsilon, \ldots\ldots(6)$$

where y is the dependent variable; β_0, β_1, β_2,... β_k are parameters; x_1, x_2,...x_k are independent variables; and ε is an experimental (random) error, independent $N(0, \sigma^2)$.

Statistical Techniques

Selection of Independent Variables

This project begins with a CEA-73 database that included 101 experiments made by several private laboratories and by Texas A&M. These experiments were the basis of the empirical models that predict regained permeability and breakthrough times. From those 101 experiments, 84 were chosen to create the basic matrix.

Regained Permeabilities (K_r) were measured in the laboratory and chosen as the dependent variable. Eight conditions were varied and measured and set as possible independent variables for the model. The conditions were:

1. Type of drill-in fluid,
2. Temperature,
3. Screen type,
4. Presence of gravel pack,
5. Formation type,
6. Type of drill solids,
7. Concentration of drill solids, and
8. Cleanup treatment

which we assigned as x_1 to x_8, respectively. Some of the conditions already had numerical value (temperature, and concentration of drill solids) as well as our dependent variable K_r. For temperature, we assigned values of 75, 110, 150 and 180°F. We varied the concentration of drill solids varied from 0% to 6%. For the other variables, assigned were normalized values relating the effect each one has in the experiments. Then the zero value was assigned to conditions with the lowest effect, and values grow as the effect increases. Each value was assigned, as is shown in Appendix A (see page 3.68).

Selection of independent variables is based on both previous studies and the data available in this study. We used criteria of R^2, adjusted R^2, MSE (mean squared error), SSE (sum of squared error), and C_p to select a "good" set of independent variables. For our statistical analysis, several terms are used in this and the following chapter, and their significance and importance of their usage are explained as follows:

Coefficient of Determination (R^2) is a measure of how well the regression equation fits the data and indicates the portion of the (corrected) total variation attributed to the fit. The remaining variation is attributed to random error. R^2 equals one if the model fits perfectly. An R^2 of zero means that the fit is no better than the mean.

Using quantities from the corresponding analysis of variance table, the R-square with an intercept in the model is calculated as

$$R^2{}_{y,x_1,x_2,\ldots x_k} = \frac{S_{yy} - SSE}{S_{yy}}, \qquad (7)$$

where $S_{yy} = \sum y_i^2 - \frac{(\sum y_i)^2}{n}$, n is the total number of observations in the sample; $SSE = \sum (y_i - \hat{y}_i)^2$, $\hat{y}_i$ is the estimator of y_i.

Since R^2 can be become larger by including a large number of independent variables, it is suggested that adjusted R^2 be used to adjust for the number of independent variables.

C(p) is a measure of total squared error that was proposed by Mallows[6] as a criterion for selecting a model. It is defined as

$$C(p) = \left(\frac{SSE_p}{s^2}\right) - (N - 2 \times p), \qquad (8)$$

where s^2 is the mean squared error for the full model and SSE_p is the error sum of squares for a model with p parameters including the intercept if any. If C(p) is plotted against p, Mallows recommends the model where C(p) first approaches p. When the right model is chosen, the parameter estimates are unbiased, and this is reflected in C(p) near p.

DF is the degree of freedom associated with each source of variation in the analysis of deviance table. A degree of freedom is subtracted from the total number of nonmissing values for each parameter estimate used in computations. The computation for the corrected total (C total) uses an estimate of the mean, so one degree of freedom is subtracted from the total. The C total degrees of freedom are partitioned into the model and error terms. The model degree of freedom is the number of parameters (except for the intercept) used to fit the model.

MSE is defined as the sum of squared error divided by the degrees of freedom for error. It is expressed as shown below:

$$MSE = \frac{SSE}{n-(k+1)} \quad \text{...(9)}$$

MSE is the estimator of error variation σ^2.

Standard Error estimates the standard deviation of the parameter estimate. It is used to construct t tests, chi-square tests, and confidence intervals for the parameter.

Standard errors of the estimates are computed using the following equation:

$$S_{xy} = \left(\frac{1}{n(n-2)}\right)\left(n\sum y^2 - \left(\sum y\right)^2 - \frac{\left(n\sum xy - \left(\sum x\right)\left(\sum y\right)\right)^2}{n\sum x^2 - \left(\sum x\right)^2}\right) \quad \text{...........(10)}$$

The adjusted R^2 statistic, an alternative to R^2 is adjusted for the degrees of freedom of the sums of squares associated with R^2. It is calculated as

$$\text{Adjusted } r^2 = 1 - \frac{(n-i)(1-r^2)}{(n-p)}, \quad \text{..(11)}$$

where n is the number of observations used in fitting the model, i is an indicator variable that is 1 if the model includes an intercept, and 0 otherwise, and p is the number of parameters in the model (including the intercept).

Because the Adj. R^2 has been adjusted for the degree of freedom, it is more (comparable) than R^2 for models involving different numbers of parameters. Unlike R^2, Adj. R^2. values need not increase as variables are added. Instead, Adj. R^2 values tend to stabilize around some upper limit as variables are added.

Based on the CEA 73 database, we conducted a preliminary statistical analysis by using SAS software and a backward elimination method select the best regression model. This method begins with the model that contains all the candidate independent variables and eliminates one variable with the smallest F value or the largest p-value at a time. The process continues until a reasonable model is found. All p-values of the final model should be less than a selected significant level α.

If independent variables in a model are highly correlated, some problems may result. One indication of the presence of serious multicollinearity is large coefficients of correlation between pairs of independent variables. A formal method of detecting the presence of multicollinearity is by means of variance inflation factors (VIF). If a VIF value is greater than 10, it is an indication of multicollinearity, which may influence the least-square estimates. If VIF values of some independent variables are too high and the variables are known to be highly correlated based on our understanding of the properties of drill-in fluids and completion techniques, one variable may be omitted from the model. The newly developed model will be then checked to see whether it is reasonable.

After formation of a regression model, an F test is applied to test whether one or some independent variables are needed to be included in the model. The general procedure is as follows: A full model and a reduced model are considered.

Full model:

$$y = \beta_0 + \beta_1 x_1 + \beta_2 x_2 + \ldots + \beta_k x_k + \varepsilon \qquad (12)$$

Reduced model:

$$y = \beta_0 + \beta_1 x_1 + \beta_2 x_2 + \ldots + \beta_g x_g + \varepsilon \qquad (k > g) \qquad (13)$$

In the reduced model, one or more independent variables have been omitted from the full model. The hypothesis (H_0) that the omitted parameter(s), β_i, equal to zero will be tested. After an F test, if the null hypothesis is not rejected, the reduced model will be chosen. The F statistic is expressed as follows:

$$F = \frac{MS_{drop}}{MSE_{full}}, \qquad (14)$$

where $MS_{drop} = \dfrac{SSE_{reduce} - SSE_{full}}{k - g}$ and $MSE_{full} = \dfrac{SSE_{full}}{n-(k+1)}$

If $F > F\alpha_{,(k-g),n-(k+1)}$, H_0 is concluded.

F Stat is the F value for testing the null hypothesis that all parameters are zero except for the intercept and is found in the analysis of variance table; in other words, F Stat is formed by dividing the mean square for model by the mean square for error. You can use the Prob. > F (p-value) to determine whether to reject the null hypothesis.

The Prob. > F value reported in the analysis of variance table is the probability of obtaining (by chance alone) a greater F statistic than that observed if the null hypothesis that none of the explanatory variables have any effect is true. The smaller the value for Prob. > F (commonly referred to as the p-value), the stronger the evidence against the null hypothesis.

In many situations researchers decide whether to reject the null hypothesis by fixed-level testing in which the p-value is compared with a predetermined cutoff denoted by α. Typical values of α are 0.01, 0.05 and 0.10. For example, if the p-value is less than 0.05, the result is reported as statistically significant; and if the p-value is less than 0.01, the result is reported as highly statistically significant. However, this is merely a convention. There is no precise cutoff between probable and improbable results. Rather than simply reporting a result as statistically significant, the recommended practice is to summarize the data and the model, indicate the test that was used, and report the *p*-value.

Occasionally the regression line is known to go through the origin at (0,0). The regression model is the same as (1) except $\beta_0 = 0$

$$y = \beta_1 x_1 + \varepsilon \quad (15)$$

An unbiased estimator of model (15) is:

$$y = b_1 x, \quad (16)$$

Where b1 is computed by

$$b_1 = \frac{\sum_{i=1}^{n} x_i y_i}{\sum_{i=1}^{n} x_i^2} \quad (17)$$

Formation of the Model

Appendix B (see page 3.69) shows the maximum R^2 improvement for the dependent variable regained permeability that we used as basis for this specific project: finding an accurate way to predict breakthrough times and regained permeability.

No further improvement in R^2 is possible for the conditions placed on this analysis.

Using the entire set of variables in a linear regression gave us a poor regression with an R^2 of 0.34 and an adjusted R^2 of 0.27 as is shown in the regression statistics of table 6.

The ending coefficients that conform to the linear regression are listed in Table 7 with its respective values of standard error, t stat, and *P*-value.

Table 8 – Regression Statistics for the Entire Database

Regression Statistics	
Multiple R	0.584334649
R^2	0.341446982
Adjusted	0.271201327
Standard	0.332277909
Observatio	84

Table 9 – Regression Description from the Entire Database

		Coefficients	**Standard Error**	**t Stat**	***P*-value**
Intercept		0.71480133	0.156007367	4.581843435	1.8E-05
DIF Type	x_1	-0.24981932	0.071161637	-3.510589819	0.00076
Temp	x_2	0.000809825	0.001295648	0.625034629	0.533845
Screen Type	x_3	0.021248173	0.057104825	0.372090678	0.710875
Gravel-Pack	x_4	0.145293632	0.137305795	1.058175528	0.293372
Form Type	x_5	-0.013193988	0.039923065	-0.330485356	0.741955
DS Type	x_6	-0.264848754	0.075945741	-3.487341742	0.000819
Conc. Drill Solids	x_7	8.256138877	2.512661832	3.285813781	0.001548
Cleanup Treatment	x_8	0.073192033	0.058501326	1.251117502	0.21478

The equation that contains these coefficients is as follows:

$$\boldsymbol{y = 0.715 - 0.25x_1 + 0.001x_2 + 0.021x_3 + 0.145x_4 - 0.013x_5 - 0.265x_6 + 8.256x_7 + 0.073x_8} \qquad (18)$$

Table 10 shows the correlation factors that are involved in the calculation of the linear equation shown above. It is important to note that the highest correlation with the dependent variable is given by x_1 (DIF type) and the lowest by x_7 (concentration of drill solids). When independent variables in a model are highly correlated, problems may occur. That could be the case given by the correlation factor between x_6 (drill solids type) and x_7 (concentration of drill solids) of 0.66. For further calculations we decided that variation of drill solids concentration would give us a better idea of the behavior of treatments than of variation of drill solids type, and it was an easier measurement factor for our purposes.

Table 10 - Correlation Factors for the Entire Database

	x_1	x_2	x_3	x_4	x_5	x_6	x_7	x_8	y
X_1	1								
X_2	).473	1							
X_3	0.446	0.288	1						
X_4	0.037	0.140	).228	1					
X_5	0.374	0.126	).629	.166	1				
X_6	).454	).423	0.299	).106	).183	1			
X_7	).280	).245	0.319	).129	).338	.660	1		
X_8	).495	).613	0.302	).166	).136	.569	).267	1	
y	0.444	0.165	).185	.085	.084	).328	).016	-0.209	1

Table 11 - Covariance Factors for The Entire Database

	x_1	x_2	x_3	x_4	x_5	x_6	x_7	x_8	y
X_1	0.457								
X_2	11.791	1360.413							
X_3	-0.266	-9.359	0.777						
X_4	-0.007	-1.424	0.056	0.076					
X_5	-0.313	-5.763	0.685	0.057	1.528				
X_6	0.239	12.142	-0.205	-0.023	-0.176	0.607			
X_7	0.004	0.186	-0.006	-0.001	-0.009	0.011	0.000		
X_8	0.304	20.523	-0.241	-0.042	-0.152	0.402	0.005	0.823	
y	-0.116	-2.348	0.063	0.009	0.040	-0.099	0.000	-0.073	0.150

Table 11 shows the covariance factors obtained from the statistical analysis of the entire database. The covariance returns the average of the product of deviations of data points from their respective means. Covariance is a measure of the relationship between two ranges of data.

$$\operatorname{cov}(x,y) = \frac{1}{n}\sum (x_i - u_{k\,x})(y_i - u_{k\,y}) \quad (19)$$

The covariance determines whether two ranges of data move together, that is, whether large values of one set are associated with large values of the other (positive covariance), or whether small values of one set are associated with large values of the other (negative covariance), or whether values in both sets are unrelated (covariance near zero).

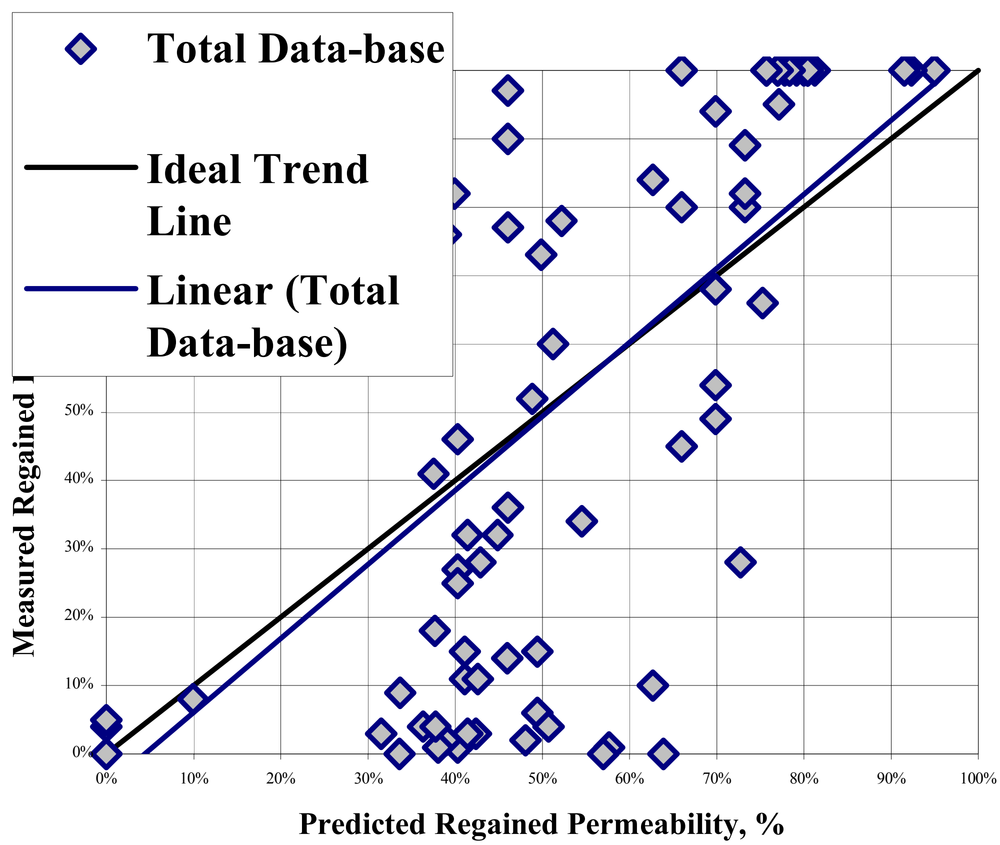


Fig. 41 – Predicted and measured values of regained permeability for the entire database

It is evident that the obtained Eq. 18 is not the proper tool to obtain accurate predictions of regained permeability, as shown in Fig. 41. Even though the applied statistics are clear, data collected from different resources as well as different technicians and different apparatus, all simultaneously, might be a high error factor in obtaining an empirical statistical regression. The first step toward the purposes of this research was to divide the database in two; this division then should provide us with a better regression. The best way of dividing the database was separating the different drill-in fluids and analyzing each one separately. From the entire set of experiments we developed a matrix of 45 experiments for SS and a matrix with 23 experiments for polymer carbonate (PC). The statistical results and the best-fit resulting equations of both matrices are shown in the following section.

Analyzing Sized Salt from the Entire Database

We achieved improved values of R^2 of 0.48 and adjusted R^2 0.39 as shown in Table 12. Following our procedure we found, as shown in Table 13, the parameters that define Eq. 20. We found a high correlation factor of 0.677 between the variables x_6 and x_7, as shown in Table 14. Table 15 still shows low values (near 0) in almost all the covariance factors, which means this regression is not yet good enough.

Table 12 - Regression Statistics for Calcium Carbonate From the Entire Database

Regression Statistics	
Multiple R	0.6960368
R Square	0.4844672
Adjusted R^2	0.386934
Standard Error	0.2741648
Observations	45

Table 13 – Regression Description for Calcium Carbonate From the Entire Database

		Coefficients	Standard Error	t Stat	*P*-value
Intercept		-0.072	0.190	-0.379	0.707
Temp	x_2	0.003	0.001	1.951	0.059
Screen Type	x_3	-0.064	0.070	-0.904	0.372
Gravel-pack?	x_4	-0.200	0.298	-0.671	0.506
Form Type	x_5	-0.023	0.041	-0.558	0.580
DS Type Code	x_6	-0.202	0.109	-1.863	0.070
Conc. Drill Solids	x_7	3.750	3.430	1.093	0.281
Cleanup Treatment	x_8	0.223	0.079	2.817	0.008

The equation that contains these coefficients is:

$$\boldsymbol{y = -0.072 + 0.003x_2 - 0.064x_3 - 0.2x_4 - 0.023x_5 - 0.202x_6 + 3.75x_7 + 0.223x_8} \quad \text{...........(20)}$$

Table 14 - Correlation Factors for Calcium Carbonate From the Entire Database

	x_2	x_3	x_4	x_5	x_6	x_7	x_8	y
X_2	1							
X_3	-0.138	1						
X_4	0.057	0.031	1					
X_5	0.024	0.572	0.062	1				
X_6	0.083	0.139	0.238	0.054	1			
X_7	-0.027	-0.195	-0.020	-0.311	0.677	1		
X_8	0.474	-0.198	0.113	-0.072	0.376	0.308	1	
y	0.445	-0.405	-0.124	-0.281	-0.088	0.141	0.500	1

Table 15 - Covariance Factors for Calcium Carbonate From the Entire Database

	x_2	x_3	x_4	x_5	x_6	x_7	x_8	y
X_2	1179.040							
X_3	-3.624	0.589						
X_4	0.290	0.004	0.022					
X_5	1.098	0.574	0.012	1.709				
X_6	1.818	0.068	0.023	0.045	0.409			
X_7	-0.019	-0.003	0.000	-0.008	0.009	0.000		
X_8	10.770	-0.101	0.011	-0.062	0.159	0.004	0.437	
Y	5.352	-0.109	-0.006	-0.128	-0.020	0.001	0.116	0.123

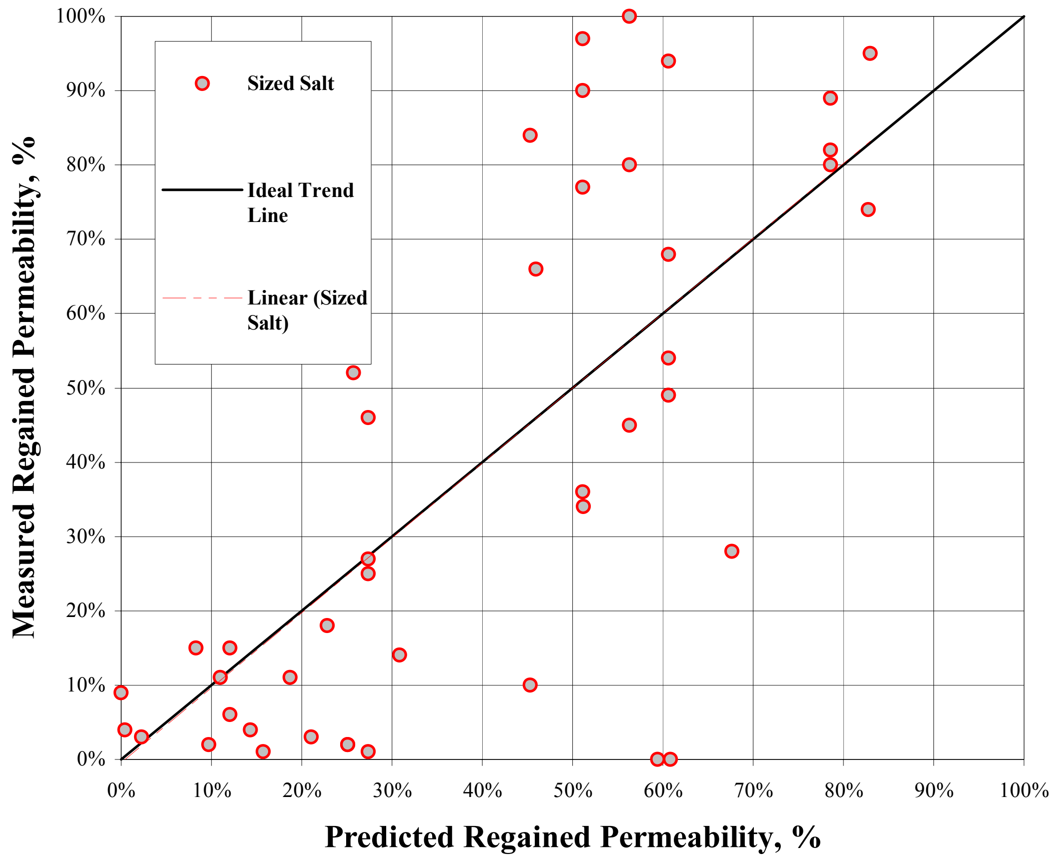


Fig. 42 – Predicted and measured values of regained permeability for sized salt from the entire database

Fig. 42 shows the predicted and measured values obtained for sized salt from the entire database. We see there that the 45° line desired is still far away from what we are getting from the entire database manipulation.

Analyzing Polymer Carbonate from the Entire Database

The polymer carbonate is giving us a better visualization of our statistical improvement for our purposes. The values of 0.61 and 0.43 for R^2 and adjusted R^2 respectively are up to now the best fit we are getting out from the database, as shown in Table 16. A value of 0.61 could be considered good enough for our purposes, and considering the empirical initial conditions of our database, we could conclude that the PC behaves more homogeneously than the SS, but a set of 23 tests with that many variables analyzed may not have enough confidence.

Table 16 - Regression Statistics for Polymer Carbonate From the Entire Database

Regression Statistics	
Multiple R	0.783053

R^2	0.613172
Adjusted R^2	0.432652
Standard Error	0.259299
Observations	23

Table 17 summarizes the parameters such as coefficients, standard error, t-stat, and *P*-values from the regression shown in Eq. 21.

Table 17 – Regression Description for Polymer Carbonate From the Entire Database

		Coefficients	Standard Error	t Stat	P-value
Intercept		0.555	0.355	1.565	0.139
Temp	x_2	-0.002	0.003	-0.851	0.408
Screen Type	x_3	0.168	0.149	1.131	0.276
Gravel-pack	x_4	-0.425	0.218	-1.955	0.069
Form Type	x_5	0.173	0.113	1.532	0.146
DS Type Code	x_6	0.006	0.093	0.061	0.952
Conc. Drill Solids	x_7	7.793	2.932	2.658	0.018
Cleanup treatment	x_8	-0.055	0.073	-0.746	0.467

The equation that contains these coefficients is:

$$\boldsymbol{y = 0.555 - 0.002x_2 + 0.168x_3 - 0.425x_4 + 0.173x_5 + 0.006x_6 + 7.793x_7 - 0.055x_8} \quad \text{..(21)}$$

This time, we can see a high correlation value of 0.848 between the variables x_4 and x_5 (Table 18), which means that those variables together will represent nuisance for our purposes of accuracy. Table 19 still shows low values near to 0 or even 0 in most of the covariance factors, which means this regression is not yet good enough. From Fig. 43 we can see that the samples of predicted and measured regained permeability are getting closer to the desired 45° line, but again, this could represent the low number of samples and the high number of variables.

Table 18 - Correlation Factors for Polymer Carbonate from the Entire Database

x_2	x_3	x_4	x_5	x_6	x_7	x_8	y

x_2	1							
x_3	0.222	1						
x_4	-0.125	0.524	1					
x_5	0.021	0.848	0.533	1				
x_6	0.245	-0.354	-0.200	-0.231	1			
x_7	0.371	-0.281	-0.218	-0.267	0.577	1		
x_8	0.122	0.143	-0.195	0.195	0.334	-0.064	1	
y	0.189	0.421	0.000	0.467	0.073	0.379	0.037	1

Table 19 - Covariance Factors for Polymer Carbonate from the Entire Database

	x_2	x_3	x_4	x_5	x_6	x_7	x_8	y
x_2	647.134							
x_3	5.069	0.806						
x_4	-1.097	0.162	0.119					
x_5	0.563	0.787	0.190	1.067				
x_6	5.721	-0.292	-0.063	-0.219	0.846			
x_7	0.248	-0.007	-0.002	-0.007	0.014	0.001		
x_8	3.024	0.125	-0.065	0.196	0.298	-0.002	0.943	
y	1.659	0.130	0.000	0.166	0.023	0.003	0.013	0.119

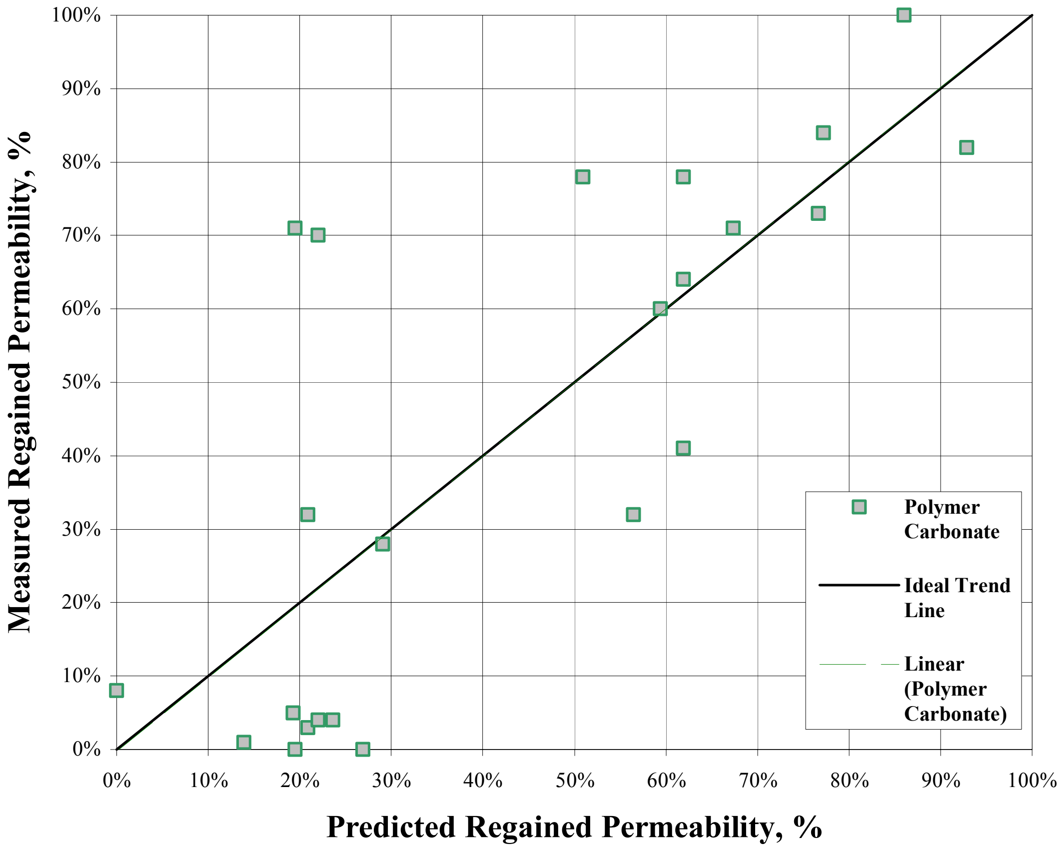


Fig. 43 – Predicted and measured values of regained permeability for polymer carbonate from the entire database

After dividing the data into two sets based on type of DIF, each set had seven independent variables. Our desire to simplify the process and provide a wider range of usage from this research led us to analyze the most significant ones. The variables x_4 and x_6 (presence of gravel pack and type of drill solids respectively) showed a continuous low, even 0, correlation and covariance factors in Tables 8, 9, 12, 13, 16, and 17. The variable x_3 has the highest correlation factor (0.848) when analyzed together with variable x_5 (screen type and formation type) as shown in Table 17, and both variables present low covariance factors. These mentioned reasons are statistically sufficient to make our regressions weak. If some of the other variables are eventually affected statistically in any table, measurement conditions of handling (as values of concentration and representation of real conditions such as temperature) make them fit as the ideal complement for our research.

The relevant importance of each variable once they are analyzed separately is seen in Figs. 44 and 45. The two charts show important relationships among the variables. On the basis of a large dataset of experiments, we have shown the relative importance of each independent variable in the change in the dependent variable (cleanup amount). For example from Fig. 44, the effect of temperature is almost 4 times as important as the effect of presence of gravel pack. This view of the database through the normalized model allows us to define a more detailed experimental matrix for more detailed tests.

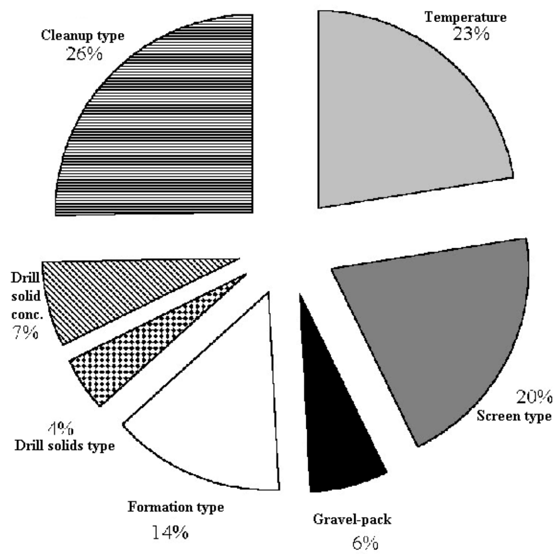


Fig. 44 – Variable weight distribution for sized salt from the entire database.

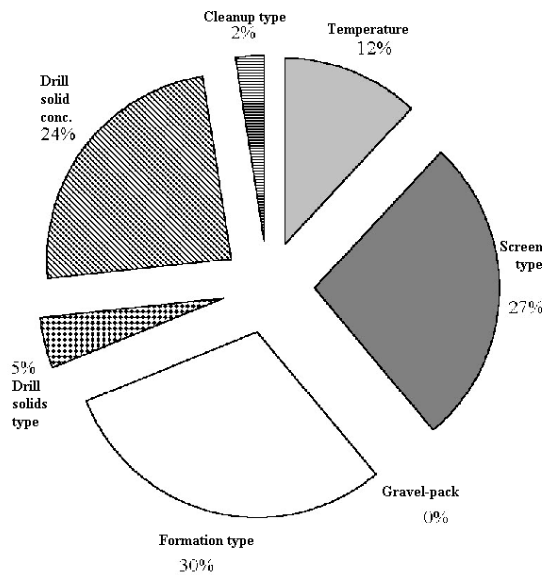


Fig. 45 – Variable weight distribution for polymer carbonate from the entire database

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Design of Experiments: Two-Level (screening) Design

On the basis of all the statistical analysis and calculations made for the original database (84 experiments with 8 independent variables) we next chose the factors for our new set of experiments. The final chosen factors were temperature, concentration of drill solids, and concentration of HCl used in the cleanup treatment. These experiments made in the same laboratory with the same apparatus and under the same conditions and supervision should give us a better data set for more accurate predictions.

We conducted four sets of experiments: two for predicting regained permeability and the other two for predicting breakthrough time. This allows work with the sized salt and polymer carbonate separately. To generate accurate equations, we had to choose what experiments to run. We chose a module called Automated Design of Experiments (ADX) that is a system that helps to construct and analyze experimental designs and used it to generate matrices with the detailed experiments we should run. The ADX method used was a two-level (screening) design. In these designs, each factor occurs at only two levels, usually a relatively high one and a relatively low one. Usually used at the initial stages of experimentation to identify design factors that significantly affect the response and to give a general notion of the dependence, in our tests we used the design was chosen to better characterize the broad volume of the experimental matrix. The two-level factors used for our set of experiments are shown in Table 20 as follows:

Table 20 – Two-Level Design Factors

Factor	Levels
Temperature	High (160 °F) Low (110 °F)
Concentration of Drill Solids	High (6%) Low (2%)
Concentration of HCl for Cleanup	High (10%) Low (2%)

Designed experiments are for studying how the value of a response variable depends on the levels of other variables, called the factors of the design. The experimental design comprises the specific combinations of levels of the design factors chosen to observe the response.
The four generated matrices with the results from measurement of all single test are shown in Tables 21, 22, 23, and 24.

Table 21 - Matrix for Regained Permeability (Sized Salt)

Obs.	Drill Solids (%)	HCl (%)	Temperature (°F)	Measured K Regained (%)
1	2	2	110	69%
2	2	10	110	85%
3	2	10	160	89%
4	2	2	160	80%
5	6	10	110	66%

6	6	2	110	40%
7	6	10	160	72%
8	6	2	160	54%

Table 22 - Matrix for Regained Permeability (Polymer Carbonate)

Obs.	**Drill Solids (%)**	**HCl (%)**	**Temperature (°F)**	**Measured K Regained (%)**
9	2	2	110	73%
10	2	10	110	88%
11	2	10	160	94%
12	2	2	160	80%
13	6	10	110	67%
14	6	2	110	47%
15	6	10	160	75%
16	6	2	160	61%

Table 23 - Matrix for Breakthrough Time (Sized Salt)

Obs.	**Drill Solids (%)**	**HCl (%)**	**Temperature (°F)**	**Measured Breakthrough Time (min)**
1	2	2	110	300
2	2	10	110	224
3	2	10	160	80
4	2	2	160	289
5	6	10	110	235
6	6	2	110	403
7	6	10	160	95
8	6	2	160	306

Table 24 - Matrix for Breakthrough Time (Polymer Carbonate)

Obs.	**Drill Solids (%)**	**HCl (%)**	**Temperature (°F)**	**Measured Breakthrough Time (min)**
9	2	2	110	50
10	2	10	110	1
11	2	10	160	1
12	2	2	160	60
13	6	10	110	32
14	6	2	110	207
15	6	10	160	25
16	6	2	160	163

ANALYSIS AND RESULTS

Since we had determined to base our work in the matrices designed in the previous chapter, we decided to organize them in a single environment to simplify the program's design. Table 25 is a matrix of the experiments performed for this research.

Table 25- Statistical Analysis Matrix

	Sized Salt	Polymer Carbonate
Regained Permeability	A	B
Breakthrough Time	C	D

Subsequently, from Table 25, Section A represents the matrix for calculating regained permeability with sized salt DIF and successively. We will follow the order of the Table 25 in our discussion of the final statistical analysis.

Once we identified the dominant independent variables in horizontal well cleanup, we renamed the variables as follows:

- Temperature, x_1
- Drill solids content, x_2, and
- Percentage of HCl in the cleanup treatment, x_3.

We applied three methods to all four matrices to measure the validity of the correlations for the conditions analyzed. First we looked for consistency in values of R^2 and Adjusted R^2 to verify the number of samples and the number of variables with confidence at the R^2 value. Then, we corroborated that R^2 value by obtaining small *P*-values, since the smaller the *P*-values the stronger the evidence that the R^2 can be trusted. Finally, confirmed visually that the values from measurement and calculation from the correlation were close to the desired 45° line in each Section's chart.

Statistical Results of the Matrices

Statistical Results for the Sized Salt, Matrix A for Regained Permeability

Table 26 shows the values of R^2 and the adjusted R^2 0.956 and 0.923 respectively. It is important to look both of them as the first juror for the correlation, but since these two parameters have close values, the R^2 itself is not affected by the number of samples measured for that number of variables.

On Table 27 we see the small *P*-values, where the largest value is 0.0514; that means the evidence could be considered strong enough. Finally Table 28 carries the values of measured and calculated regained permeability to be graphed in Fig. 46. Fig. 46 shows a close correlation between the measured and calculated regained permeability with the points near the 45° line.

Table 26 - Regression Statistics from Matrix for Regained Permeability (Sized Salt)

Regression Statistics

Multiple R	0.977775093
R^2	0.956044132
Adjusted R^2	0.923077232
Standard Error	0.04462986
Observations	8

Table 27 - Regression Description From Matrix for Regained Permeability (Sized Salt)

		Coefficients	Standard Error	t Stat	*P*-value
Intercept		0.55625625	0.09521182	5.84230239	0.00427973
Temperature °F	X_1	0.00173502	0.00063116	2.74893888	0.05143048
Drill Solids (%)	x_2	-5.59804426	0.78895192	-7.09554548	0.00208344
HCl (%)	x_3	2.12786543	0.39447596	5.39415741	0.00571440

The equation that contains these coefficients is:

$y = 0.55626 + 0.00174x_1 - 5.59804x_2 + 2.12787x_3$ ....(22)

Table 28 - Matrix for Regained Permeability (Sized Salt) With Calculated Data from Eq. 22 Included

Obs.	Temp., °F	HCl	Drill Solids, %	Measured K Regained	Calculated K Regained
1	110	2	2	69%	68%
2	110	10	2	85%	85%
3	160	10	2	89%	93%
4	160	2	2	80%	76%
5	110	10	6	66%	62%
6	110	2	6	40%	45%
7	160	10	6	72%	71%
8	160	2	6	54%	54%

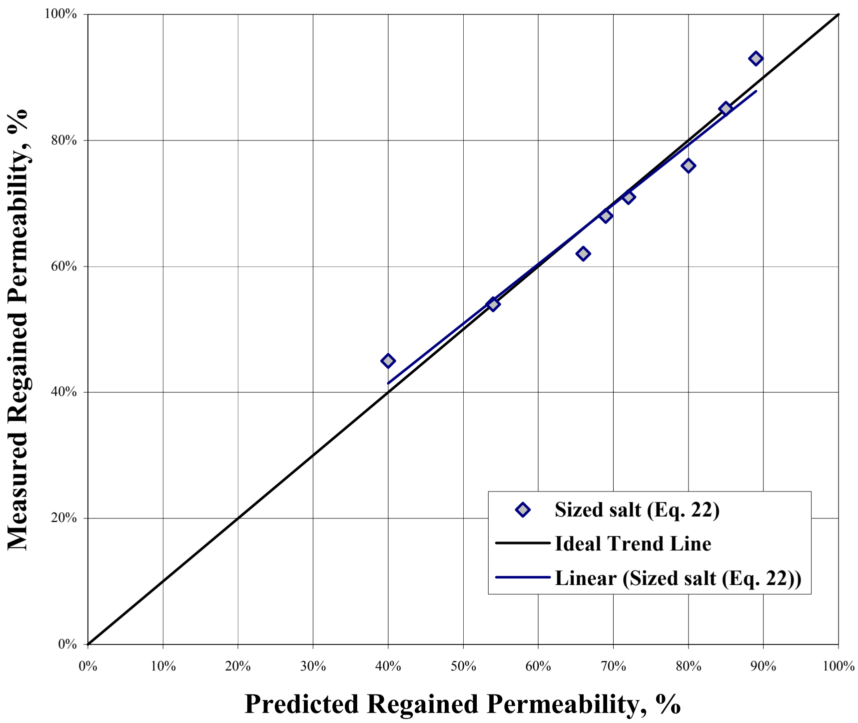

Fig. 46 – Measured and predicted regained permeability for sized salt from final regression

Statistical Results for the Polymer Carbonate, Matrix B for Regained Permeability

Table 29 shows the values of R^2 and the adjusted R^2, 0.9857 and 0.975 respectively. Here again we see close values, meaning that the number of samples measured for that number of variables does not affect the R^2 term.
On Table 30 we see the small *P*-values, where the largest value is 0.00638; that means the correlation is strong. Finally, Table 31 carries the values of measured and calculated regained permeability to be graphed in Fig. 47. Fig. 47 shows a close correlation between the measured and calculated regained permeability with the points placed near the 45° line.

Table 29 - Regression Statistics From Matrix for Regained Permeability (Polymer Carbonate)

Regression Statistics	
Multiple R	0.992839989
R^2	0.985731244
Adjusted R^2	0.975029678
Standard Error	0.023667809
Observations	8

Table 30 - Regression Description from Matrix for Regained Permeability (Polymer Carbonate)

		Coefficients	Standard Error	t Stat	P-value
Intercept		0.58972569	0.0504920	11.6795646	0.00030726
Temperature °F	x_1	0.00175067	0.0003347	5.23036479	0.00638209
Drill Solids (%)	x_2	-5.29307016	0.4183917	-12.6509922	0.00022478
HCl (%)	x_3	1.97275638	0.2091958	9.43018888	0.00070500

The equation that contains these coefficients is:

$$y = 0.58973 + 0.00175x_1 - 5.29307x_2 + 1.97276x_3 \qquad (23)$$

Table 31 - Matrix for Regained Permeability (Polymer Carbonate) With Calculated Data From Eq. 23 Included

Obs	Temp. °F	HCl	Drill Solids, %	Measured K Regained	Calculated K Regained
9	110	2	2	73%	72%
10	110	10	2	88%	87%
11	160	10	2	94%	96%
12	160	2	2	80%	80%
13	110	10	6	67%	66%
14	110	2	6	47%	50%
15	160	10	6	75%	75%
16	160	2	6	61%	59%

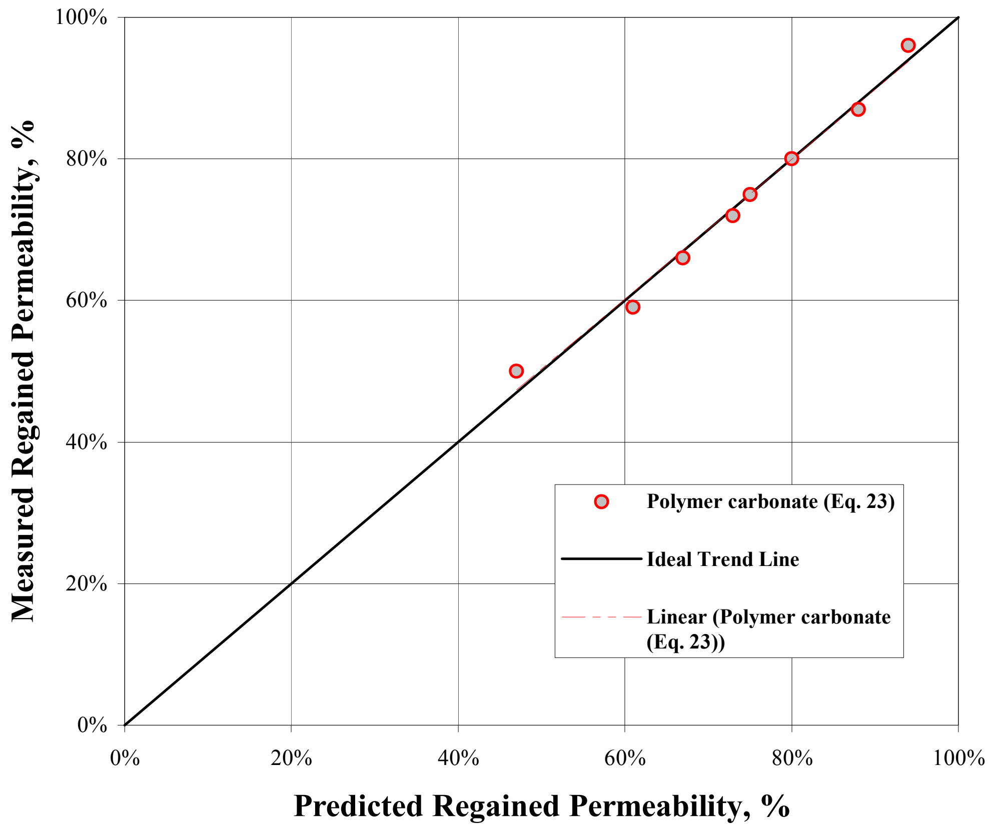

Fig. 47 – Measured and predicted regained permeability for polymer carbonate from final regression

Statistics Results for the Sized Salt, Matrix C for Breakthrough Time
Table 30 shows the values of R^2 and the adjusted R^2 0.9185 and 0.8574 respectively. Here again we see close values, meaning that the number of samples measured for that number of variables does not affect the R^2 itself. On Table 31 we see the small *P*-values where the largest value is 0.2797 (small enough for our purposes); that means the evidence could be considered strong enough. Finally, Table 32 carries the values of measured and calculated regained permeability to be graphed in Fig. 48. Fig. 48 shows a satisfactory correlation between the measured and calculated regained permeability with the points placed near the 45° line.

Table 32 - Regression Statistics from Matrix for Breakthrough Time (Sized Salt)

Regression Statistics	
Multiple R	0.958392404
R^2	0.918516
Adjusted R^2	0.857402999
Standard Error	41.32039448
Observations	8

Table 33 - Regression Description from Matrix for Breakthrough Time (Sized Salt)

		Coefficients	Standard Error	t Stat	*P*-value
Intercept	x_1	594.1	88.1515199	6.73953211	0.002526
Temperature °F		-1.96	0.58435863	-3.35410469	0.02846013
Drill Solids (%)	x_2	9.125	7.30448278	1.24923287	0.27969204
HCl (%)	x_3	-20.75	3.65224139	-5.68144264	0.00473751

The equation that contains these coefficients is:

$$y = 594.1 - 1.9675x_1 + 9.125x_2 - 20.75x_3 \qquad (24)$$

Table 34 - Matrix for Breakthrough Time (Sized Salt) With Calculated Data from Eq. 24 Included

Obs	Drill Solids, %	HCl, %	Temp., °F	Measured Breakthrough Time, min	Calculated Breakthrough Time, min
1	2	2	110	300	355
2	2	10	110	224	189
3	2	10	160	80	91
4	2	2	160	289	257
5	6	10	110	235	226
6	6	2	110	403	392
7	6	10	160	95	128
8	6	2	160	306	294

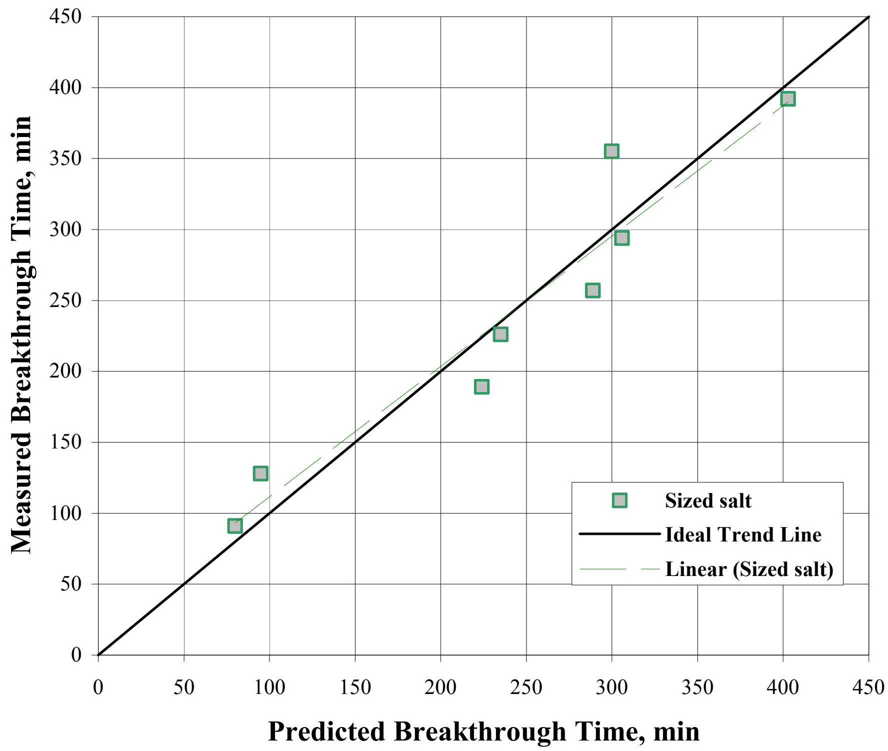

Fig. 48 – Measured and predicted breakthrough time for sized salt from final regression

Statistics Results for the Polymer Carbonate, Matrix D for Breakthrough Time

Table 35 shows the values of R^2 and the adjusted R^2, 0.851 and 0.7393 respectively. Once again we see close values, meaning that the number of samples measured for that number of variables does not affect the R^2 term.

On Table 36 we see the small *P*-values, where the largest value is 0.729 (small enough for our purposes); that means the evidence could be considered strong enough. Finally, Table 35 carries the values of measured and calculated regained permeability to be graphed in Fig. 49. Fig. 49 shows a satisfactory correlation between the measured and calculated breakthrough time with the points placed near the 45° line.

Table 35 - Regression Statistics From Matrix for Breakthrough Time (Polymer Carbonate)

Regression Statistics	
Multiple R	0.922519529
R^2	0.851042282
Adjusted R^2	0.739323993
Standard Error	39.0048074
Observations	8

Table 36 - Regression Description From Matrix for Breakthrough Time (Polymer Carbonate)

		Coefficients	Standard Error	t Stat	*P*-value
Intercept		95.2375	83.21152546	1.144522943	0.316238959
Temperature °F	x_1	-0.205	0.551611276	-0.371638523	0.729010854
Drill Solids (%)	x_2	19.6875	6.895140952	2.85527158	0.046149296
HCl (%)	x_3	-13.15625	3.447570476	-3.816093127	0.018841327

The equation that contains these coefficients is:

$$y = 95.2375 - 0.205x_1 + 19.68755x_2 - 13.15625x_3 \quad (25)$$

Table 37 - Matrix for Breakthrough Time (Polymer Carbonate) With Calculated Data From Eq. 25 Included

Obs	Drill Solids, %	HCl, %	Temp. , °F	Measured Breakthrough Time, min	Calculated Breakthrough Time, min
9	2	2	110	50	86
10	2	10	110	1	0
11	2	10	160	1	0
12	2	2	160	60	76
13	6	10	110	32	59
14	6	2	110	207	165
15	6	10	160	25	49
16	6	2	160	163	154

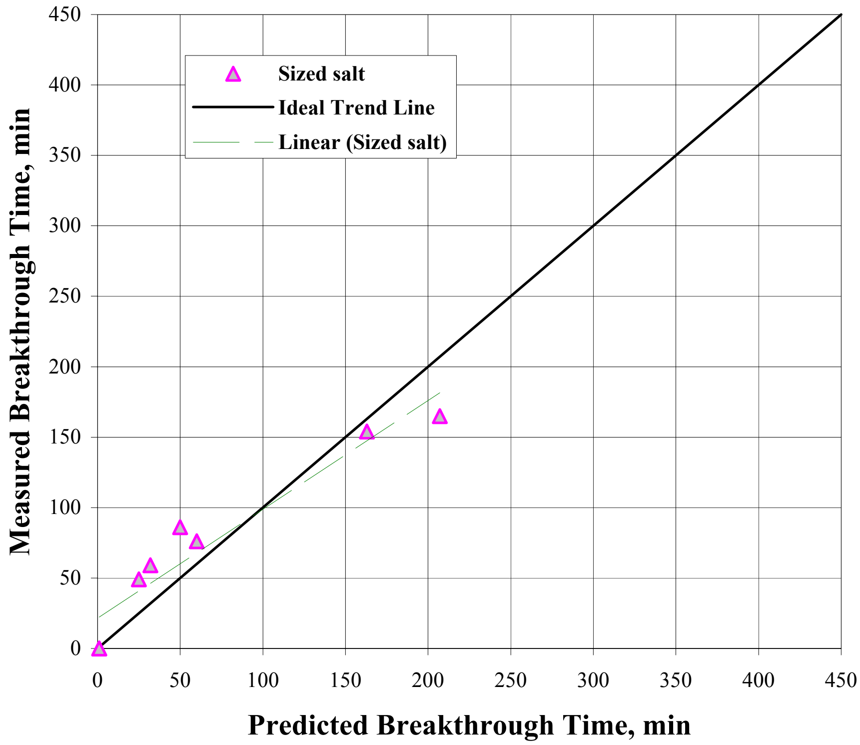

Fig. 49 – Measured and predicted breakthrough time for polymer carbonate from final regression

General Behavior of the Results Analyzing Regained Permeability

The following charts show the variation of regained permeability for a range of HCl and drill solids content between 1 and 10%. The ranges were made by using Eqs. 18 to 21 respectively. Looking at Figs. 50 to 53, we observe that the higher the HCl concentration, the higher the expected regained permeability. From the same figures we can see that the lower the drill solids content, the higher the regained permeability. These two sets of experiments (Matrices A and B) presented a homogeneous behavior with very close slope degrees.

Comparing Figs. 50 with 51 and 52 with 53, we note that the temperature enhances the effect of the acid, making it react faster at higher temperatures while the effect from drill solids content is barely noted. In Fig. 50 the regained permeability varies from the lowest value of 25% at 1% of HCl and 10% of drill solids content to the highest value of 95% at 10% of HCl and 1% of drill solids content; while in Fig. 51 the regained permeability varies from the lowest value of 35% at 1% of HCl and 10% of drill solids content to the highest value of 100% at 10% of HCl and 1% of drill solids content.

In Fig. 52 the regained permeability varies from the lowest value of 20% at 1% of HCl and 10% of drill solids content to the highest value of 90% at 10% of HCl and 1% of drill solids content; while in Fig. 53 the regained permeability varies from the lowest value of 40% at 1% of HCl and 10% of drill solids content to the highest value of 100% at 10% of HCl and 1% of drill solids content. Comparing Figs. 15 with 17 and 16 with 18 we observe that the polymer carbonate presents a constant 5% improvement in regained permeabilities over the sized calcium carbonate at the same conditions of temperature, drill solids content, and percentage of HCl in the cleanup treatment.

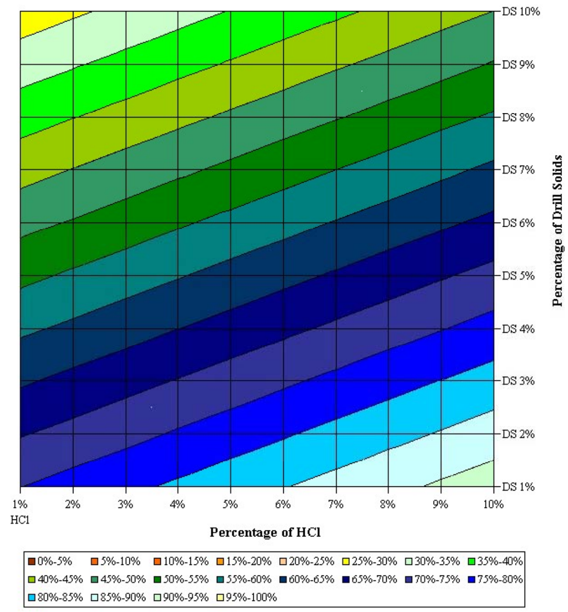

Fig. 50 – Variation of regained permeability for sized salt DIF at 110°F

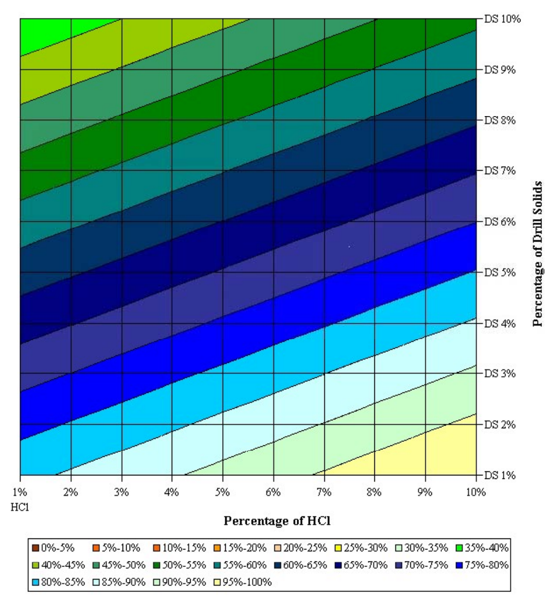

Fig. 51 – Variation of regained permeability for sized salt DIF at 160°F

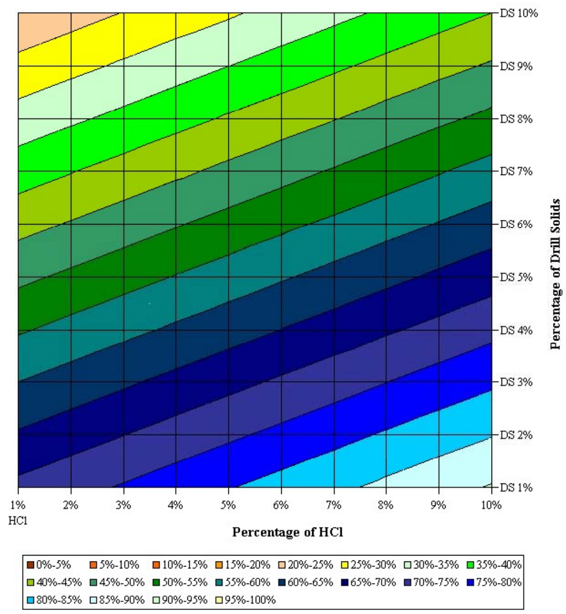

Fig. 52 – Variation of regained permeability for polymer carbonate at 110°F

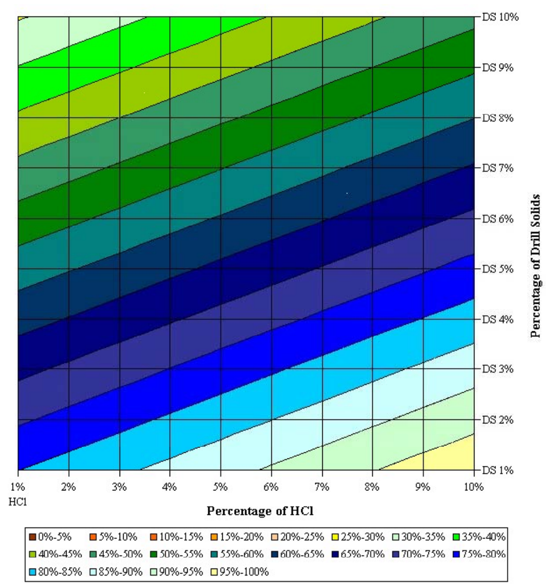

Fig. 53 – Variation of regained permeability for polymer carbonate at 160°F

Analyzing Breakthrough Time

The following charts show the variation of breakthrough time for a range of percentage of HCl and drill solids content between 1 and 10%. These ranges were made by using Eqs. 22 to 25 respectively. Looking at Figs. 54 to 57 we observe that the higher the HCl concentration, the faster the expected response of breakthrough time. From the same figures we can see that the lower the drill solids content, the faster the expected breakthrough time.

Comparing Figs. 54 with 55, we note that the temperature did not materially affect action of the acid, although it made it react more efficiently at higher temperatures while the effect from drill solids content is barely noted. In both figures, the breakthrough time has the same range, varying from the lowest value of 0 minutes at 10% of HCl and 1% of drill solids content up to the highest value of 260 minutes at 1% of HCl and 10% of drill solids content. Also note in this comparison that the lower range (0 to 20 minutes) is more accentuated in Fig. 20 that has the highest temperature, but in the same figure the range of highest range (240 to 260 minutes) is barely noticeable. In these figures the slope is very similar.

Comparing Figs. 56 with 57, we note that the temperature affects substantially more the action of the acid, making it react more efficiently at higher temperatures while the effect from drill solids content is again barely noted. In both figures, the breakthrough time has very different ranges varying from the lowest value of 180 minutes at 10% of HCl and 1% of drill solids content up to the highest value of 440 minutes at 1% of HCl and 10% of drill solids content in Fig. 56, and from the lowest value of 80 minutes at 10% of HCl and 1% of drill solids content up to the highest value of 340 minutes at 1% of HCl and 10% of drill solids content in Fig. 57. The 100-minute range difference between them is also easily seen. In these figures the slope is very similar. Comparing Figs. 19 with 21 and 20 with 22 we realize that the polymer carbonate reacts notably at lower rates than the sized salt, and the difference is even higher when the temperature is lower (110°F) where the sized salt requires 440 minutes; at the same conditions, the polymer only takes 260 minutes.

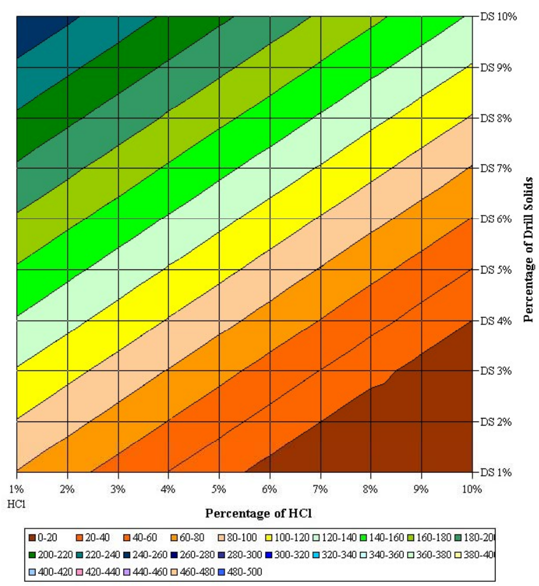

Fig. 54 – Variation of breakthrough time for sized salt at 110°F

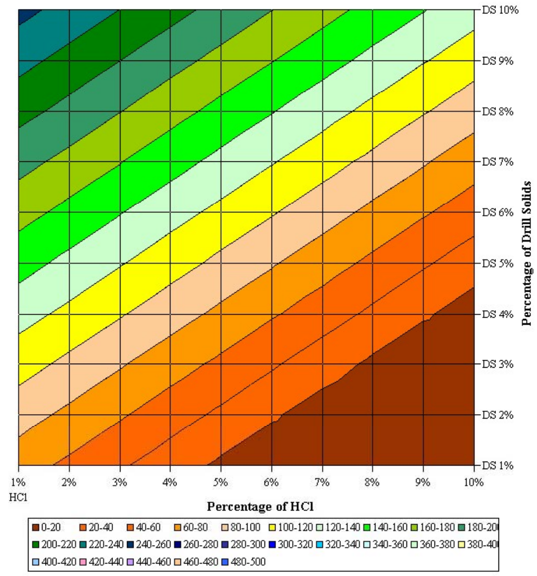

Fig. 55 – Variation of breakthrough time for sized salt at 160°F

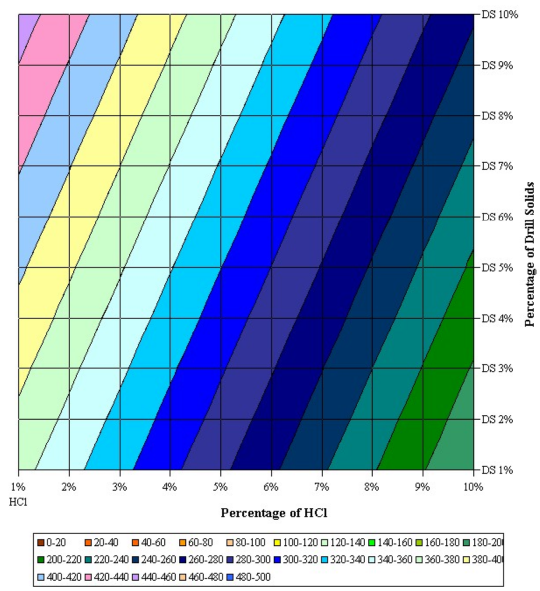

Fig. 56 – Variation of breakthrough time for polymer carbonate at 110°F

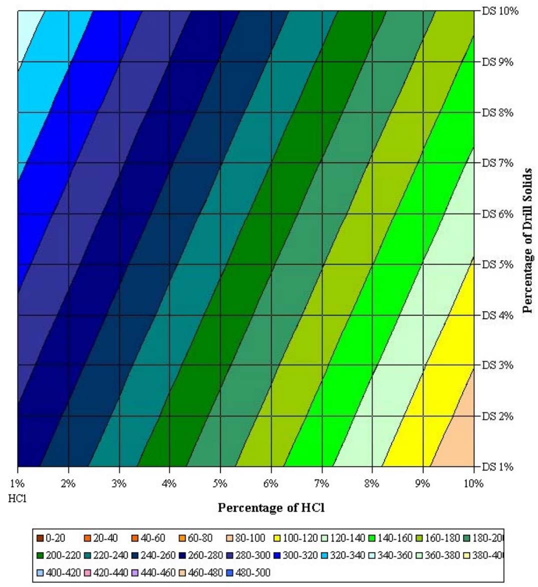

Fig. 57 – Variation of breakthrough time for polymer carbonate at 160°F

Conclusions

This research has presented the process that includes experimental work on DIF's in an effort to evaluate the formation damage effect and find statistical correlations to predict regained permeability and breakthrough time. It has also included the entire process, from measurement of properties through statistical design to evaluation of our models. The laboratory work included tests with a linear-flow cell to measure regained permeability, and with a ceramic disk cell to predict breakthrough time. After preliminary statistical studies to identify and select key variables, we selected three independent factors to include in the correlation process -drill solids concentration, hydrochloric acid concentration, and temperature- separated for each type of DIF. The statistical process included the selection of variables, the experimental design, and the development of the correlation.

This research has provided the first predictive models for formation damage and cleanup treatment for similar conditions presented in the field.

The main conclusions drawn from this statistical study are as follows:

1. Temperature, as a statistical variable, does not produce a substantial effect in derived correlations, but it reflects an important factor that differentiates the treated gulf sands.
2. Values of R^2 between 0.851 and 0.986 corroborated by close values of adjusted R^2 and low *P*-values give validity to the correlations found and identified as Eqs. 21 to 25 under the conditions of these types of DIF's, temperatures of 110 and 160°F, hydrochloric acid concentrations of 2 and 10% in the cleanup treatment, and drill solid content of 2% and 6% in the drill-in fluids. The models are statistically valid for the ranges studied.

3. Under identical conditions the regained permeability showed a 5%-better performance with the sized salt over the polymer carbonate, and of 10 to 20% better over the temperature range tested.
4. The experimental range created for the regained permeability analyses showed a homogeneous slope and relative low changes among conditions. This is different from the ranges created for the breakthrough times, which maintained the same slope for the same type of drill-in fluid, but differed among types.
5. Breakthrough time rates have showed a 100-minute better performance for the polymer carbonate than the sized salt.
6. Drill solids content is inversely proportional to both regained permeability and breakthrough time because hydrochloric acid cannot dissolve such particles.
7. Hydrochloric acid content in the cleanup treatment is directly proportional to the regained permeability performance as well as the breakthrough time performance. Temperature affects the acid effect proportionally.

Appendix A

Table A1-Values Assigned to Initial Variables of the Database

Variable	Value	
Type of drill-in fluid	0	None
	1	Sized Calcium Carbonate
	2	Polymer Carbonate
Screen type	0	None
		Wesco
	1	Baker Hughes
		Other 12/20
	2	Any 20/40
	3	Any 40/60
	4	Wire mesh
Presence of gravel pack	0	None
	1	Present
Formation type	0	Unknown sand
	1	Sand 1
	2	Sand 2
	3	Sand 3
	4	Sand 4
Type of drill-solids	0	None
	1	Illitic/Smectite
	2	Rev Dust
Cleanup treatment	0	None
	1	Dilute brine
	1.5	Mudzyme X2. 5% HCl
	2	Brine/HCl (2%)
	3	72 Hr. soak
	4	Mudzyme S2. 10% HCl

Appendix B

Table B2- Summary of Stepwise Statistics Analysis for Entire Database

Step	Included Variables	Regression Statistics		Regression
1	x_1	R^2 = 0.196796 $C_{(p)}$ = 11.47374 P-value = 0.0001	DF = 1 F = 20.1	$y = 0.795 - 0.2538x_1$
2	x_1, x_7	R^2 = 0.218175 $C_{(p)}$ = 11.03898 P-value = 0.0001	DF = 2 F = 11.3	$y = 0.788 - 0.2782x_1 + 2.8558x_7$
3	x_1, x_7, x_6	R^2 = 0.307354 $C_{(p)}$ = 2.882769 P-value = 0.0001	DF = 3 F = 11.8	$y = 0.836 - 0.2067x_1 - 0.2128x_6 + 7.5046x_7$
4	x_1, x_7, x_6, x_8	R^2 = 0.326716 $C_{(p)}$ = 2.677695 P-value = 0.0001	DF = 4 F = 9.58	$y = 0.8104 - 0.2372x_1 - 0.263x_6 + 8.126x_7 + 0.0775x_8$
5	x_1, x_7, x_6, x_8, x_4	R^2 = 0.336957 $C_{(p)}$ = 3.511335 P-value = 0.0001	DF = 5 F = 7.93	$y = 0.792 - 0.2414x_1 + 0.1447x_4 - 0.2666x_6 + 8.3993x_7 + 0.0864x_8$
6	$x_1, x_7, x_6, x_8, x_4, x_2$	R^2 = 0.340014 $C_{(p)}$ = 5.163259 P-value = 0.0001	DF = 6 F = 6.61	$y = 0.726 - 0.2502x_1 + 0.0008x_2 + 0.1493x_4 - 0.2676x_6 + 8.3535x_7 + 0.0718x_8$
7	$x_1, x_7, x_6, x_8, x_4, x_2, x_3$	R^2 = 0.340488 $C_{(p)}$ = 7.109221 P-value = 0.0001	DF = 7 F = 5.61	$y = 0.708 - 0.2448x_1 + 0.0008x_2 + 0.0113x_3 + 0.1429x_4 - 0.2687x_6 + 8.46x_7 + 0.0724x_8$
8	$x_1, x_7, x_6, x_8, x_4, x_2, x_3, x_5$	R^2 = 0.341447 $C_{(p)}$ = 9 P-value = 0.0001	DF = 8 F = 4.86	$y = 0.7148 - 0.2498x_1 + 0.0008x_2 + 0.0212x_3 + 0.1453x_4 - 0.0132x_5 - 0.2648x_6 + 8.2561x_7 + 0.0732x_8$

CHAPTER 4

New Types of Drill In Fluids 1: Low Damage DIFs

A new series of formation damage tests have been performed for new reservoir DIF systems recently launched to the market. A polymer free system (DIPRO^{TM}), and a high temperature system (potassium formate-based) were investigated. This report presents a summary of results obtained. The main objective of this project is to study the performance of these new fluids in terms of formation damage on unconsolidated sand. To accomplish the objective, measurements of return permeability and break through times were developed.

The DIFs have been developed to address the formation damage control issues highlighted by tests at the A&M Completions Laboratory as well as by Conoco, ARCO, and other CEA 73 sponsors. TBC Brinadd, a sponsor has commercialized DiPro and has licensed it exclusively to MI Drilling Fluids, LLC. This material is now being used in both Gulf of Mexico and in West Africa operations. At the time of this report (April, 2003) more than five field well projects have been reported.

The Conoco Cell apparatus was used to measure return permeability. Ceramic Disc technique was used to measure break through times. Conventional lab methods were used in order to measure the DIF properties.

DIF Formulation

The DIF's built at lab conditions have the following additives:

Table 38 - Composition of DiPro^{TM} System.

Product	amount	Units	Observations
11.6 ppg. CaCl2	207	ml	Base Brine
Tap water	136	ml	Dilution media
Starch	8	gr	Viscosifier
Magnesium Oxide	0.25	gr	Ph stabilizer
Sized Calcium Carbonate - 2	8	gr	Fluid loss control
Sized Calcium Carbonate - 5	9	gr	Fluid loss control
Sized Calcium Carbonate - 12	9	gr	Fluid loss control

Table 39 - Composition of Formate System.

Product	amount	Units	Observations
Formate	343	ml	Base Brine (12.2 ppg)
Formatrol	5	ppb	Viscosifier
Biopolymer	0.75	ppb	Viscosifier
Sized Calcium Carbonate - 2	8	ppb	Fluid loss control
Sized Calcium Carbonate - 5	9	ppb	Fluid loss control
Sized Calcium Carbonate - 12	9	ppb	Fluid loss control

Performance of New DIF (DiPro$^{TM)}$ DIFs

Break through time and return permeability analysis was developed using the following variables:

- Temperature: 110 and 160 °F
- Drill Solids contained: 2 and 6 % (Volume)
- Clean-up: HCl Acid at 2 and 10%, and 3% KCl brine.

Results from Break through time analysis are shown in Appendix 1. Almost immediate break through times were seen at 10% HCl acid at any temperature and at 160°F with any acid concentration. At 110°F and low acid concentration (2%) break through times were approximately 100 min. Break through times reached using conventional completion brine such as KCl brine were 93 min. for 160°F temperature and 64 to 161 min. for 110°F. The statistical analysis of results gave us the following linear relationship among variables:

$$BT = 177.63 - 0.7967*T + 462.5*DS - 912.5*HCl$$

Where:

BT = Break Through time, min.
T = Temperature, °F.
DS = Drill Solids Contained, fraction
HCl = HCl Acid concentration, fraction

Nevertheless, it should be said that the standard errors are high and the data correlation is not good as can be corroborated on the Figure 5.1: Results from Return permeability tests are shown in Annex 1. A better statistical result and data correlation is observed (Figure 5.2). The linear relationship is given by the following equation:

$$RP = -0.3755 + 0.0059*T + 2.299*DS + 3.693*HCl$$

Where:
RP = Return Permeability, fraction.

Return permeability values range from 43 to 100% being higher for higher temperatures, acid concentration and Drill solids contained.

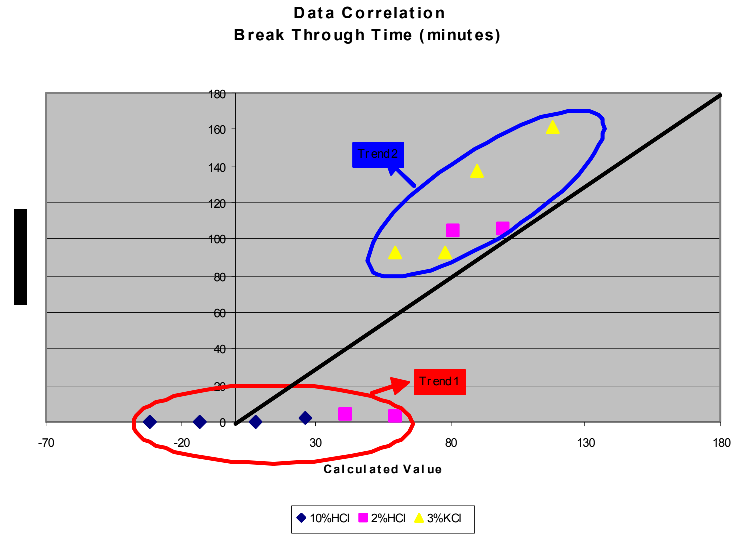

Figure 58. **Break through time correlation for 10.5 ppg. DiPro fluid**.

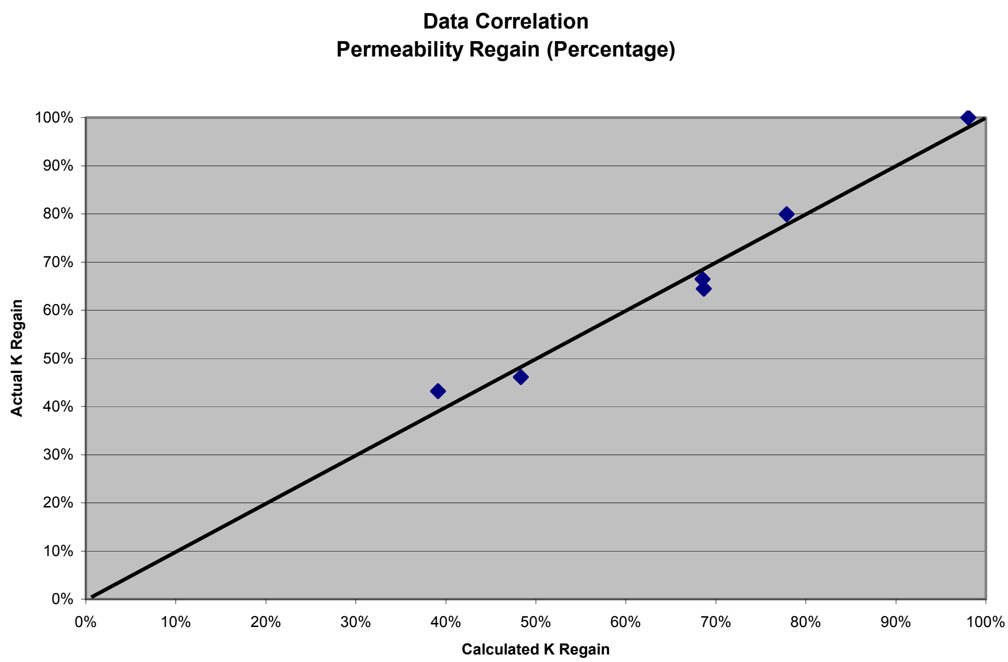

Figure 59 Permeability regain correlation for 10.5 ppg. Dipro fluid.

Taking into account the low break through time values obtained when HCl acid is used, the behavior with a less strong acid as cleaning-up fluid was investigated. Acetic acid at 10 and 15% concentration was chosen. The fluid density was also changed increasing it to about 13 ppg by using 14.2 ppg $CaBr_2$ base brine instead of $CaCl_2$. For break through time analysis, temperature ranges of 110 and 160°F and Drill Solids contain of 2 and 6% were used. The results are summarized in the Appendix 5.2. Break through times about 90 min. were obtained at 160°F independently of acid concentration and drill solids contain. At 110°F temperature, values between 62 – 144 were reached without showing a particular trend. The best linear relationship was obtained taking out the highest value (considered abnormal). The following is the resulting equation:

$$BT = 49.357 + 0.257*T + 68.57*AC - 239.285*DS$$

Where:

AC = Acetic Acid concentration, fraction.

Figure 60 shows the data correlation which could be considered adequate although should be noticed that the values tend to be grouped around 90 minutes.

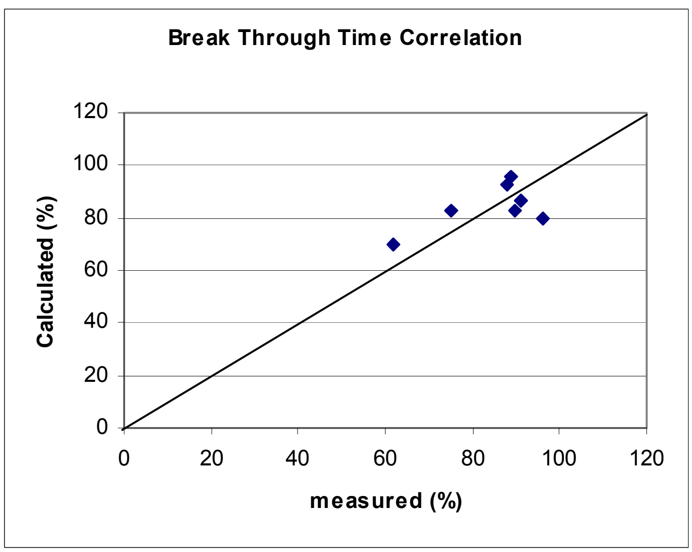

Figure 60 Breakthrough Time correlation for 13 ppg. Dipro fluid

It was noticed that the cleaning was not homogeneous through the ceramic face, showing a pinhole pattern as can be seen in the Figure 61.

Figure 61 Ceramic discs after break through tests, using 13 ppg Dipro fluid and acetic acid as cleaning fluid.

Return permeability tests for 2% Drill solids and acid concentrations of 10 and 15% were run for this fluid. The results are shown in Figure 62 At 110°F temperature, return permeability values around 20% were obtained and 40% at 150°F with a value above 100%. As it was noticed in the case with ceramic disc test, the sand face after regain permeability test showed partially removal of filtercake. Due to low values and high disparity observed with the data no further experiments were made with higher drill solids contain.

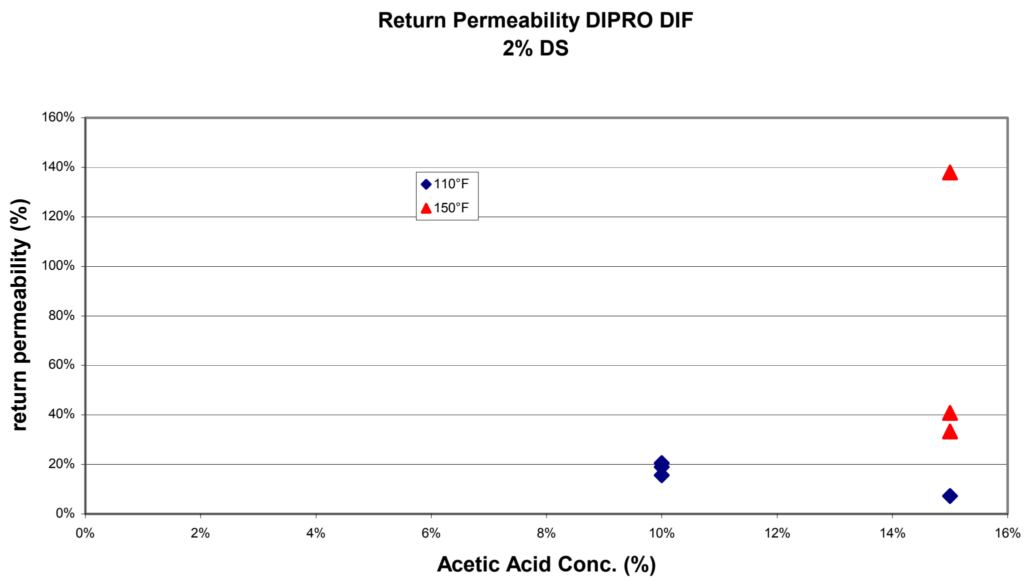

Figure 62 Return Permeability results for 13 ppg. Dipro fluid.

Some essays were tried using a breaker into the DIF. Polyglycolic acid at 1, 3, and 6 ppb was used. The fluid rheology and pH was monitored during a period of time after adding the breaker in order to identify the breaker reaction. The fluid was hot rolled at 140°F simulating reservoir conditions. It was noticed that pH changes from 10 to 7 almost immediately after adding the breaker and stabilizes at 6 for subsequent days. Plastic Viscosity does not change appreciable. Gel properties begin to decrease until reaching a value of 2. The Yield Point is maintained during certain period of time and then begins to decrease in almost a constant rate. Figure 63 shows a general behavior of all parameters examined.

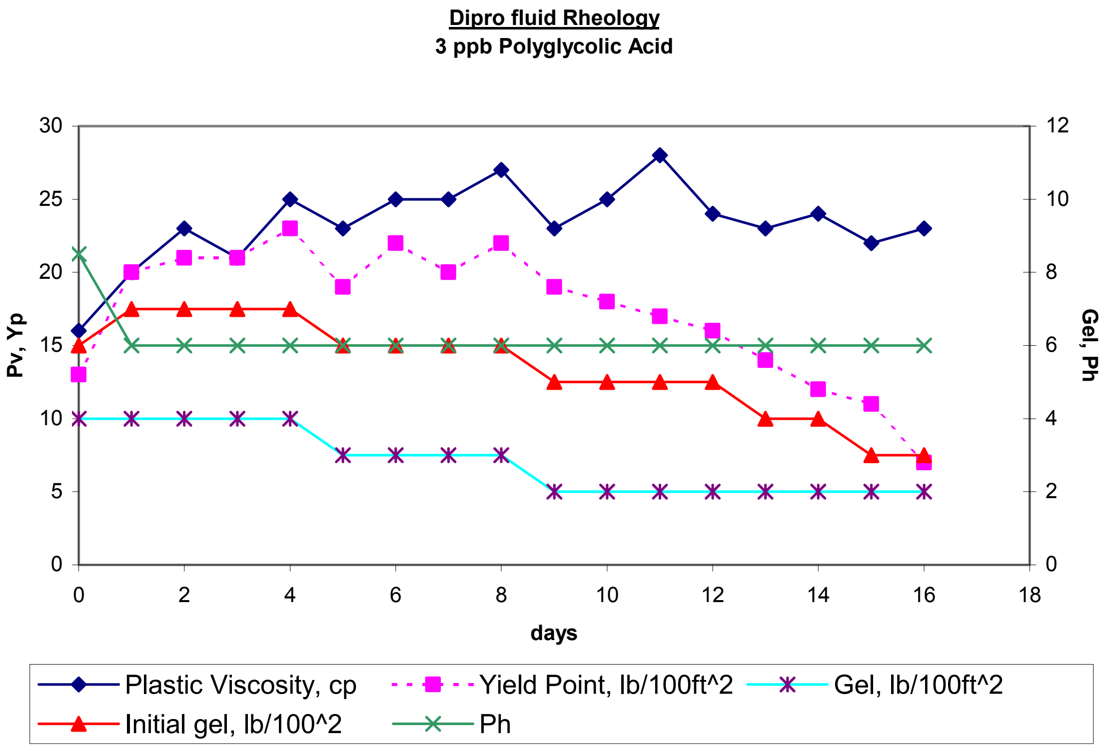

Figure 63 General rheology behavior for Dipro fluid after adding breaker additive.

The time reaction of breaker was identified when Yield point begins the straight line decreasing behavior and Gel value reaches its minimal value of 2. Figures 64 - 66 show the results for each sample analyzed, and Figure 67 show the results in terms of time reaction against breaker concentration.

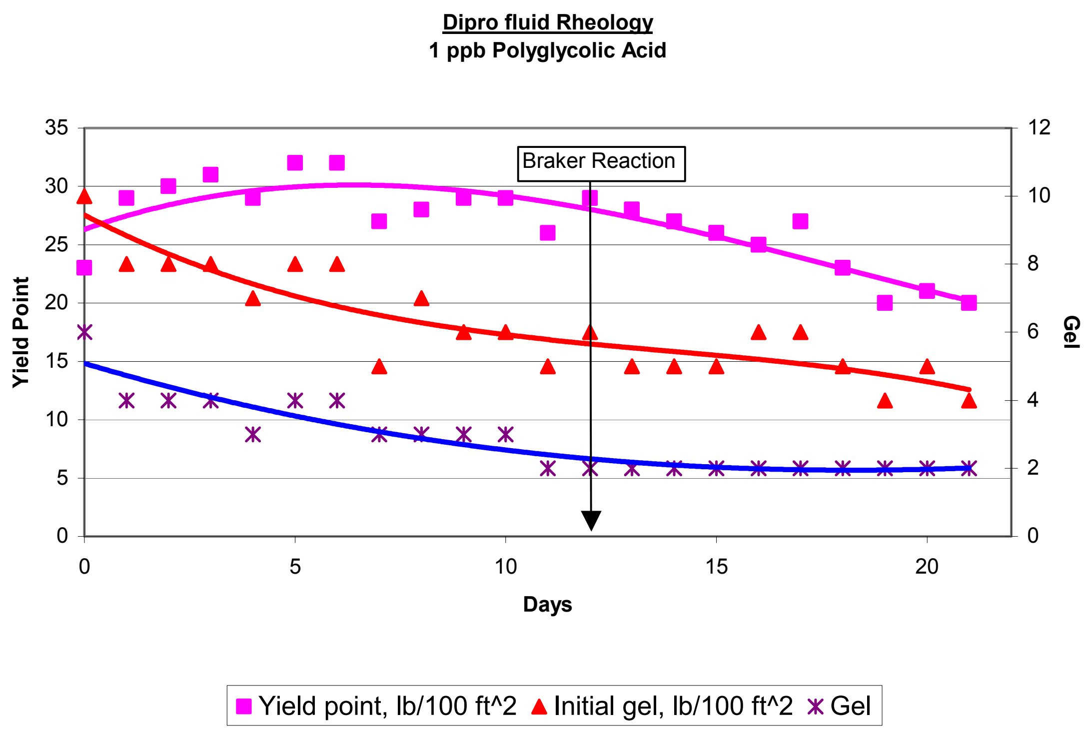

Figure 64. Rheology behavior for 13 ppg. Dipro fluid with 1ppb polyglycolic acid.

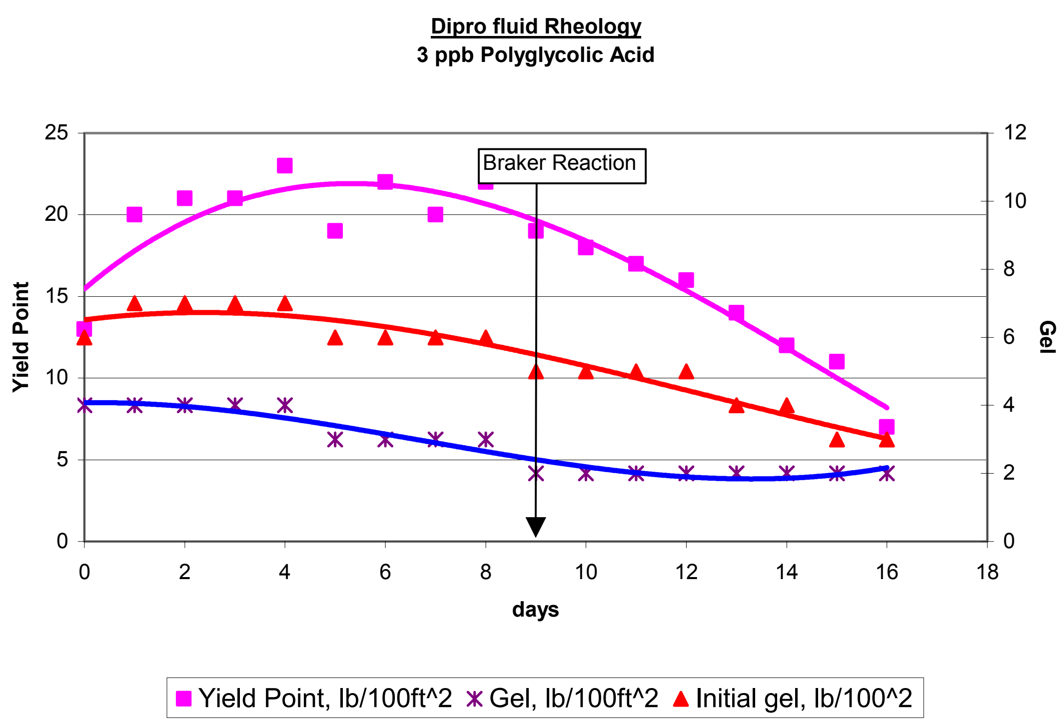

Figure 65 Rheology behavior for 10 ppg. Dipro fluid with 3ppb polyglycolic acid.

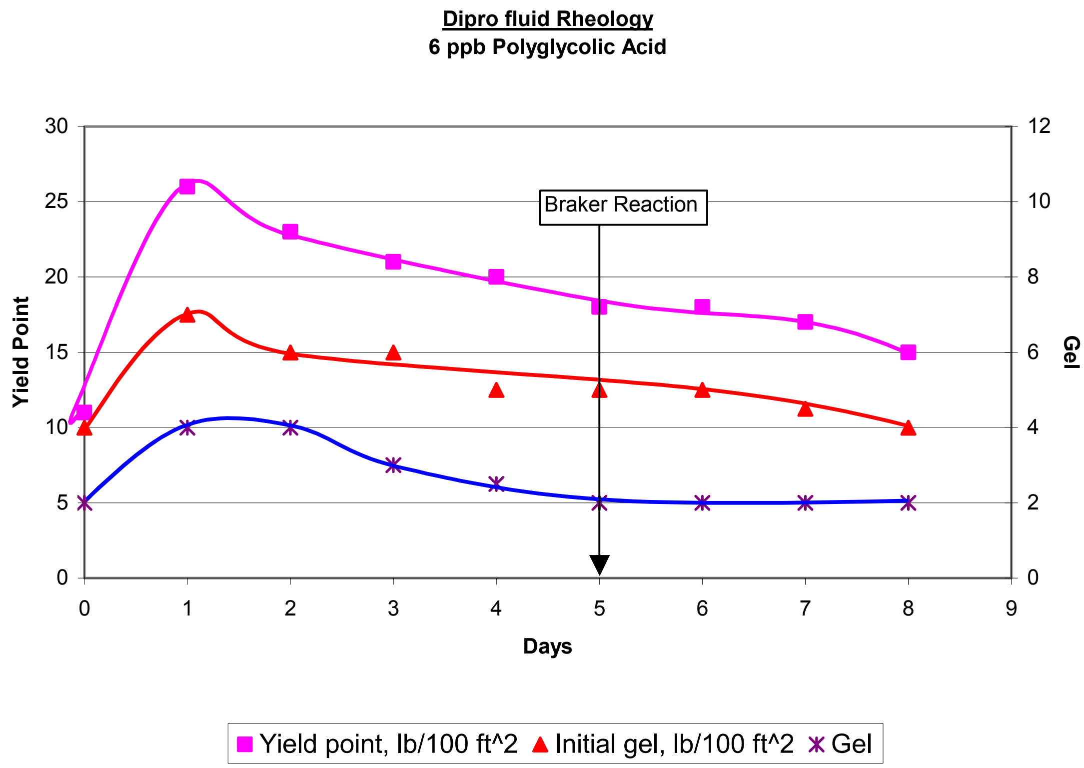

Figure 66 Rheology behavior for 10 ppg. Dipro fluid with 6ppb polyglycolic acid.

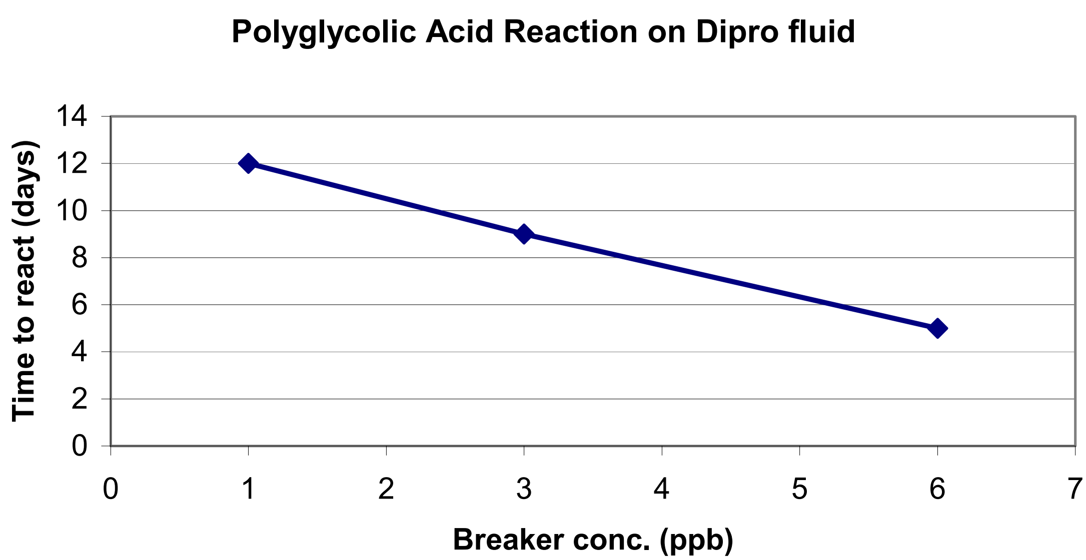

Figure 67 Breaker reaction vs. Concentration.

Formate System:

Some return permeability tests were run using the Formate system. At 160°F with 2% DS and using acetic acid as cleaning fluid at 10%, the lowest value of return permeability observed was 61% with tests showing near to 100% values. At higher temperatures for which this system is formulated, better results should be reached.

Discussion of Performance of New DIF.

The reactivity of the HCl acid with Dipro system at high temperatures (160°F or above) and high acid concentration is too quick producing difficulties in getting and adequate filtercake cleaning. Using HCl as cleaning fluid at low concentration (around 2%) for low temperature applications (110°F) could be more efficient, nevertheless the return permeability expected could be around 50%.

The use of less strong acids such as acetic to clean up Dipro systems can result in better reactivity times but the cleaning could be non-homogeneous producing a pin-hole pattern. Due to this, some areas could be very well cleaned while others not so good and the final results in terms of return permeability can be difficult to determine.

Polyglycolic acid breakes the Dipro system approximately in 12 days using it at 1 ppb concentration and 5 days using it at 6 ppb concentration. The best way to determine breaking reaction could be measurements of Yield point and fluid gel.

It would be highly recommendable to analyze field data from wells where this product has been used in order to get more definitive conclusions.

On the other hand, acetic acid could be a good alternative to clean and restore adequately formation permeability when Formate systems are used.

More experimentation for Formate fluid at application temperatures can be valuable to determine its performance. Unfortunately there is limitation with the equipment currently used in our lab.

Appendix 5.1

Results and data analysis for 10.5 ppg DiPro fluid and HCl cleaning acid.

		Break Time (min)		
Temp °F	**drill solids**	**HCl 10%**	**HCl 2%**	**KCl 3%**
110	0	0	0	138
110	2	0	105	64*
110	6	2	106	161
160	2	0	4	93
160	6	>84	3	93

* Test run at different pressure value.

Table 5A.1. Break Through Time obtained for 10.5 Dipro system using different cleanup formulations

Regression Statistics	
R Square	0.6901
Adjusted R Square	0.5868
Coef. Variance	65.19191
Observations	14

	Coefficients	***Standard Error***	***t Stat***	***P-value***
Intercept	177.6333	55.05994	3.23	0.0104
T°	-0.79667	0.40290	-1.98	0.0794
HCl (%)	-912.5	234.06187	-3.9	0.0036
DS (%)	462.5	459.37299	1.01	0.3403

Table 5A.2. Regression Analysis results for Break Through Time.

Temp °F	Drill Solids %	HCl %	K Regain %
110	2%	2%	43.21%
110	2%	10%	64.47%
110	6%	2%	46.13%
110	6%	10%	79.95%
160	2%	2%	66.45%
160	2%	10%	100.00%

Table 5A.3. Regain permeability results for 10.5 ppg Dipro fluid

.

Regression Statistics	
R Square	0.9773
Adjusted R Square	0.9432
Coef. Variance	7.60624
Observations	6

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	-0.37547	0.15854	-2.37	0.1414
T°	0.00588	0.00101	5.79	0.0286
HCl (%)	3.69271	0.51781	7.13	0.0191
DS (%)	2.29925	1.26838	1.81	0.2116

Table 5A.4. Regression Analysis results for Permeability Regain.

Appendix 2

Results and data analysis for 13.0 ppg DiPro fluid and Acetic cleaning acid.

Temp	DS	Acid Concentration	Break through time	
			Measured	Calculated
110	2%	10%	96	80
110	6%	10%	62	70
110	2%	15%	75	83
160	2%	10%	88	93
160	6%	10%	90	83
160	2%	15%	89	96
160	6%	15%	91	86

Table 5A.5. Break Through Time obtained for 13.0 Dipro system using acetic acid as cleanup fluid.

Regression Statistics	
R Square	0.4421
Adjusted R Square	-0.1158
Coef. Variance	14.74834
Observations	7

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	49.35714	32.98471	1.5	0.2315
T°	0.25714	0.19405	1.33	0.277
Acetic Acid (%)	68.57143	210.47404	0.33	0.766
DS (%)	-239.28571	263.09254	-0.91	0.4301

Table 5A.6. Regression Analysis results for Break through time.

CHAPTER 5

New Types of Drill In Fluids 2: Low Density DIF

Introduction

The increasing number of open hole horizontal well completions in low-pressure and depleted reservoirs requires the use of non-damaging low-density drill-in fluids (LDDIF) to avoid formation damage and realize optimum well productivity. To address this need we have formulated new LDDIFs with specific density lower than 1.0 sg (8.34 ppg) specifically to drill and complete low pressure and depleted reservoirs with minimum formation damage and maximum production. These materials exhibit typical drilling fluid characteristics, allowing the well to be safely drilled to required well depth, but also perform as completion fluids, lessening formation damage to a greater extent than fluids with greater density and higher wellbore pressures.

The new LDDIF incorporates low-density hollow glass spheres (HGS) to allow near-balanced drilling in low pressure and depleted reservoirs. The LDDIF uses potassium chloride (KCl) brine as the base fluid because of its low density and inhibition of clay hydration and employs low concentrations of the HGS so that fluid rheology is not altered.

More and more companies have been turning to horizontal well technology to access low-pressure and depleted reservoirs. The redevelopment of old fields call for nondamaging, low-density DIF (LDDIF) [1]. Engineers involved in the oil industry have been trying to develop and study economical and environmentally friendly LDDIF that are suitable for use in low-pressure and depleted reservoirs with less risk of damaging the reservoir formation. These trends, together with the continuing development and use of open hole completions have resulted in increasing reliance on formation damage testing to select the appropriate LDDIF and cleanup technique.

This project is a part of CEA (Completion Engineering Association) 73 program. The CEA 73 program debuted in 1995 to study formation damage caused by DIFs and cleanup technology for openhole horizontal completions. During the past years, Falla,[2] Serrano,[3] Gutierrez,[4] and Hale *et al*.[5] have conducted their research on polymer-free (PF), sized salt (SS), and sized calcium carbonate (SCC) DIF systems. They carefully studied the formation damage and cleanup performance of these DIFs in horizontal well, unconsolidated sand completions. Through laboratory tests and analysis, we know that this LDDIF cause less formation damage than conventional DIF, particularly in depleted and/or low-pressure reservoirs.

DIF Used in Low-pressure and Depleted Reservoirs

Several types of DIF suitable to low-pressure and depleted reservoir formations have been developed. Brookey[6] documented the successful use of aphron DIF for horizontal drilling through low-pressure reservoirs. This fluid combines surfactants and polymers to create a system of "micro-bubbles" known as Aphrons encapsulated in a uniquely viscosified system. A unique feature of the micro-bubble network, stopping or slowing the entry of fluids into the formation, creates downhole bridging. Case histories showed no problems with formation damage or inhibited production. Luo *et al*.[7] developed a new DIF that contains an elastic fiber-shaped additive, calcium carbonate particles, polymer and salt, clay and water. Experiment results indicated that it could reduce formation damage by 20% to 40% compared to the conventional DIF. Holt *et al*.[8] presented the successful application of diesel as horizontal DIF in depleted Nubia sandstone, Sidki Field. Diesel, identified as the best fluid for its low density and little damage, was used to complete the lateral section in the first well and to drill the remaining three horizontal sections. Unfortunately, Holt did not address the environmental concerns.

Breakthrough and Cleanup Technology

Different kinds of cleanup procedures have been employed to achieve better well performance. The most popular method is the use of acids to dissolve filtercake and polymers. A common disadvantage of the treatment is that acids are highly reactive and may remove the filtercake at the point of circulation before the treatment can be placed over the entire openhole interval.

Filtercake can be effectively removed by applying an enzyme-based polymer degradation system. Beall, B. *et al.*[9] documented a successful case history of such a system. This treatment can be designed to degrade xanthan-based, starch-based or cellulose-based drill-in fluid cake. Field experience has shown this new technology allows smaller, less costly treatments to be used to treat openhole intervals to zero-skin potential with improved efficiency. Lynn *et al.*[10] developed cleanup procedures using different kinds of mild stimulation fluids during pre-completion. The fluids were enzyme breakers, surfactant washes, and mild acids. Although good performance was found using these "exotic fluids," the highest values of regained permeability were obtained when acid wash was applied, indicating inclusive stimulation processes.

Underdown *et al.*[11] studied problems related with the use of HAc (Acetic Acid) treatments in the presence of special mineral components in rocks such as analcime. These minerals form a hydrous aluminosilicate gel in the presence of strong acids causing formation plugging. The use of acetic acid resulted in a good alternative for these cases.

HGS Low Density Drill In Fluids

We use S38 (Characteristics are given in **Table 1**) hollow glass spheres as density-deducing agent because it has suitable properties for use in drill-in fluid. **Table 2** gives the formulation of 10% HGS, 8.06 ppg LDDIF. It is based on 3% KCl brine. In our lab, this LDDIF composition tested with offset tests of non-HGS DIF. LDDIF provides rheological properties similar to traditional DIFs used in horizontal well drilling and completion operations. The rheological properties of LDDIF, without drill solids and with 2% drill solids, are summarized in **Table 3**.

HGS Effect on Formation Damage

The average pore size of a formation (D_p) is approximated by taking the square root of the permeability (in millidarcies).[12] The pore size of the simulated unconsolidated sand formation is found by equation (1). Here k ranges from 100 md to 1,000 md, so D_p is between 10.0 and 31.6 μm.

$$D_p = \sqrt{k} \tag{1}$$

According to pore bridging theory, particles that are one-third of the average pore size of the formation will get trapped in the pore and initiate a bridge. Smaller particles will pass through the formation, whereas larger ones will pack on the surface and not seal properly. The particle size distribution (PSD) of HGS range from 8 to 125 μm, whereas PSD of drill solids is largely scattered from 0.01 μm to 10,000 μm. **Fig. 1** clearly shows their PSD.

From the PSD of HGS, we know that very few HGS particles can plug the pores of an unconsolidated formation. Almost all the HGS particles will only pack on the formation surface and can easily be removed once the production initiates. **Fig. 2** shows how HGS pack on the formation surface and are to be removed by initial oil flow. Bridging agents contain Ultracarb, which are readily dissolved by acids. To some extent, the formation "surface wall" formed by hollow glass spheres may result in fewer invasions of fine particles such as drill solids. Eventually, HGS does not cause additional formation damage, but can protect the reservoir formation to some degree.

Laboratory Methods

To achieve the research objectives, laboratory tests have been conducted to study the LDDIF behaviors at different conditions. We have performed the standard tests of breakthrough time (BT) and ratio of regained permeability (RP) to initial permeability at 0% HGS and 10% HGS LDDIF with varying concentrations of drill solids at different conditions. The test procedures have been described in **Chapter 2**.

Measuring Breakthrough Time (BT)

We use the ceramic disk cell to measure breakthrough time. This tool was created with the goal of testing the time that a certain cleaning treatment takes to flow through the filtercake, which is built by pressured LDDIF in contact with the ceramic cell. The procedure is:

Before starting the procedure, a new ceramic disc of approximately 1 Darcy is placed at the bottom of the cell. On the first Step, the titanium cylinder is filled with LDDIF. Then, the titanium cell is pressured at 200 psi and at 110 or 160°F for 2 hours, which allows the buildup of filtercake on top of the mentioned ceramic disc as shown in Step 1 of **Fig. 3**.

After that, the remaining LDDIF left in the cylinder is evacuated as shown in **Fig. 3** (Step 2), and the cleanup agent is injected (**Fig. 3**, Step 3). Next the cleanup agent is trapped in the cell at 100 psi at the same temperature with filtercake buildup, and minute-to-minute leakoff is measured from the system. The outlet-line valve is left open, and the time is counted once the first drop appears. When the clean-up treatment flows through the ceramic disk, we know the time taken for the cleaning treatment to flow through the filter cake.

Measuring Regained Permeability (RP)

To measure the regained permeability, the Conoco Cell (linear flow cell) was used. The Conoco cell is the only available device able to simulate the collapse of the filtercake. This system was designed to measure cleanup efficiency by simulating filter cake buildup and wellbore cleanup in horizontal openhole completions. The cell consists of a 1.95-cm-diameter and 1.572-cm- length sand module pack (core holder) to simulate the borehole wall and a 3.4-cm- diameter disk of metallic screen to simulate the openhole completion. The test procedure was four Steps: measure the initial permeability of the sand model, wellbore filtercake buildup, wellbore filtercake cleanup, and measure the final regained permeability of the sand model after cleanup.

Before starting the test, the sand is firmly packed into the core holder and saturated with tap water. To achieve more reliable and accurate data, we used the same amount of sand in each individual test.

1) Measure Initial Permeability of Sand Model

On Step 1 (**Fig. 4**) tap water is injected to flow through the firmly packed sand model. Laminar flow is reached. At this point, we measure the initial permeability of the sand model. The rate Q_n is measured as well as the pressure difference; the other parameters are standard for the cell as mentioned before. Darcy's law equation (Eq.2) is applied to calculate permeabilities:

$$K_i = \frac{6.8 \times Q_n \times \mu_w \times L_{Core}}{A_{Core} \times \Delta P} \qquad (2)$$

2) Filtercake Buildup

Once the initial permeability is measured, the next Step is to build the filtercake. The core holder is backed off to create a clearance between the sand module and the screen holder in the cell allowing room enough to apply the drill-in fluid and build the filtercake. 200 psi is applied for 4 hours at temperatures of 110 or 160 °F to simulate reservoir conditions (this is shown in Step 2 of **Fig. 4**). After 4 hours, the remaining drill-in fluid is removed and the filtercake is formed on sand module.

3) Cleanup Treatment

The clean up solution is injected across the cell as shown of Step 3 in **Fig. 4**. The treatment flows slowly for about 1 hour.

4) Measure Final Permeability

Then we repeat the Step 1, measuring the permeability of the sand module after cleanup, which is illustrated in **Fig. 4** as Step 4.

Once the initial and final permeabilities are both measured, then the ratio of regained permeability to initial permeability is obtained by equation (3) as follows:

$$RP = \frac{K_f}{K_i} \times 100\% \qquad (3)$$

Tests Variables

All of the laboratory tests were accomplished under several sets of conditions. Three main variables were considered in our tests:

- Drill solids concentration
- Temperature: 110 and 160°F
- Cleanup agent: HCl and HAc

Additionally, all the tests were run with offset non-HGS DIF.

Analysis and Discussion

For both breakthrough time and regained permeability tests, we ran tests of 10% HGS LDDIF to compare with non-HGS DIF, then repeated both tests under different experimental variables.

Analysis and Discussion of Breakthrough Time

Tests were developed to consider two different scenarios:

- HGS LDDIF vs. non-HGS DIF.
- Using HCl as breakthrough agent.

Breakthrough Time of HGS LDDIF and Non-HGS DIF:

The purpose of the test was to evaluate the effect of HGS on breakthrough time. In the offset tests, we evaluated two kinds of fluid: 10% HGS LDDIF and non-HGS DIF, both with 7% drill solids. We used 2% HCl as the cleanup agent, tests were run at: 160 °F and 100 psi differential pressure. We the measured and compared the breakthrough time and average filtering rate of the cleanup agent.

Figs. 5 and **6** graphically give the experimental results. It is evident that:

- The filtercake of 10% HGS LDDIF was much more easily removed than that of non-HGS DIF. Breakthrough times for non-HGS is twice as long as that of 10% HGS.

- The leakoff rate of 10% HGS LDDIF was much greater than that of non-HGS DIF, almost eight times.

The experimental results indicate that the filtercake of 10% HGS LDDIF is easier to remove than non-HGS. Other conditions being equal, HGS-containing fluids will be easier to remove from the formation surface. According to the breakthrough time tests, we do know that glass bubbles do not damage the reservoir formation, but it does help to protect reservoir formation.

HCl as Breakthrough Agent: Hydrochloric acid is commonly used in horizontal openhole completions. In our tests, we used two different concentrations: 5% and 10% HCl.

All tests were run with 10% HGS LDDIF. We use SPSS to perform linear regression. The linear correlation is:

$$BT_{pred} = 139.25 - 0.65 \times T + 0.0 \times DS - 2.2 \times HCl \quad (4)$$

From **Fig. 7**, we can see that the measured BT correlates with the predicted BT very well. From the regression results and figures we know that:

From linear Equation 4, we know that HCl concentration is more important than any other variables: temperature and drill solids.
Drill solids concentration has almost no effect on breakthrough time.
Equation 4 can be used to predict breakthrough time with HCl as breakthrough agent.
The predicted BT is fairly close to the measured BT.

HAc as Breakthrough Agent: Acetic acid (HAc), weaker and less corrosive than HCl, is not so often used in openhole horizontal well completion as HCl. Because of the ease of removal of the LDDIF, we tested this less reactive acid. In our tests, we used two different concentrations: 10% HAc and 15% HAc.

All tests were run with 10% HGS LDDIF. The linear correlation is:

$BT_{pred} = 211.25 - 0.955 \times T + 0.65 \times DS - 1.75 \times HAc$ (5)

From **Fig. 8**, we can see that the measured BT correlates with the predicted BT very well, better than that of HCl. From the regression results and figures we know that

From linear Equation 5, we know that HAc concentration plays a more important role than any other variables: temperature and drill solids.
BT goes up with the increase of DS concentration,
Equation 5 can be used to predict breakthrough time with HAc as breakthrough agent.
The predicted BT is fairly close to the measured BT.

Analysis and Discussion of RP Data

Tests were developed to consider three different scenarios:

- HGS LDDIF vs. non-HGS DIF.
- Using HCl as cleanup treatment.
- Using HAc as cleanup treatment.

RP of HGS LDDIF and Non-HGS DIF: The purpose of the tests is to evaluate the effect of HGS on regained permeability. In the offset tests, we evaluated two kinds of fluids: 10% HGS LDDIF and non-HGS DIF, both without drill solids. 5% and 10% HCl were used as cleanup treatment. Tests were run at 110°F and 160°F. We measured and compared the ratio of regained permeability.

Fig. 9 gives the experimental results. It is evident that:

- The RP value of non-HGS DIF and HGS LDDIF is very close, so HGS do not cause additional formation damage.

HCl as Cleanup Treatment: Hydrochloric acid is commonly used in horizontal openhole completions as cleanup treatment. In our tests, we used two different concentrations: 5% and 10% HCl.

All tests were run with 10% HGS LDDIF. The linear correlation is:

$RP_{pred} = 13.112 + 0.132 \times T + 12.475 \times DS + 2.667 \times HCl$ (6)

From linear correlation Equation 6 and **Fig. 10** we know that

- The predicted RP correlates well with the measured RP.
- DS concentration plays a more important role than any other two variables. Temperature has the least influence on RP.
- RP increases with an increase of HCl concentration, higher temperature, and higher

DS concentration.

We infer that extremely good cleanup and high-regained permeability is an indication that HCl is too reactive for complete cleanup in long horizontal wellbores.

HAc as Cleanup Treatment: In our tests, we used two different concentrations: 10%, and 15% HAc.

All tests were run with 10% HGS LDDIF. The linear correlation is:

$RP_{pred} = 120.846 - 0.551 \times T - 5.601 \times DS + 2.598 \times HAc$ (7)

From Equation 7 and **Fig. 11,** we know that:

The predicted RP is very close to the measured RP.
DS concentration plays more important role than any other two variables.
Temperature has the least influence on RP.
The RP increases with increased HAc concentration, but decreases with higher temperature and higher DS concentration.
The data suggest that HAc is also very reactive and would probably cause early breakthrough in long wellbores.

Comparison of LDDIF With Other Types DIF

Serrano[2] carefully studied and evaluated the formation damage behaviors of sized salt (SS) DIF and sized calcium carbonate (SCC) DIF. Falla[1] did the same work with polymer free (PF) DIF. **Figs. 12** and **13** give the comparison of breakthrough time and regained permeability of new HGS LDDIF with SS DIF, SCC DIF, PF DIF. LDDIF had the least breakthrough time while SCC had the longest BT. For regained permeability, there are no big differences among the four types of DIFs.

Conclusions

The main conclusions are:

- Analysis of LDDIF formation damage mechanisms indicates that HGS does not cause any additional formation damage to reservoir zones. To some extent, the formation “surface wall” formed by hollow glass spheres may result in less invasion of fine particles, such as drill solids.

- For comparison tests of breakthrough time with 2% HCl break agent, 100 psi differential pressure, and 160°F, the breakthrough time of 10% HGS LDDIF is half that of non-HGS DIF and the leakoff rate of 10% HGS LDDIF is much greater than that of non-HGS DIF. Data show that the filtercake of 10% HGS LDDIF is easier to be broken through and removed than that of non-HGS.

- When HCl was used as the breakthrough agent, HCl concentration plays more important role than temperature and DS concentration in affecting BT. When higher HCl concentration and higher temperature were present, lower BT was obtained. DS concentration has almost no contribution to BT in this case.

- When HAc was used as the breakthrough agent, HAc concentration was the most important variable contributing to BT. BT increased with higher DS concentration and it decreased with higher temperature and higher HAc concentration.

- Linear multivariate model was found to predict RP when HCl and HAc were used as cleanup treatments for HGS LDDIF. DS concentration played an important role in affecting RP.

- For the RP comparison test, we got very close RP of HGS LDDIF and non-HGS DIF, 51.14% and 52.41%, respectively. The conclusion is that hollow glass spheres do not cause additional damage to formation permeabilities.

- When compared with SS, SCC, and PF DIFs, LDDIF had the fastest breakthrough time. Also the ratio of regained permeability of HGS LDDIF was the smallest, although there are no big differences among RP.

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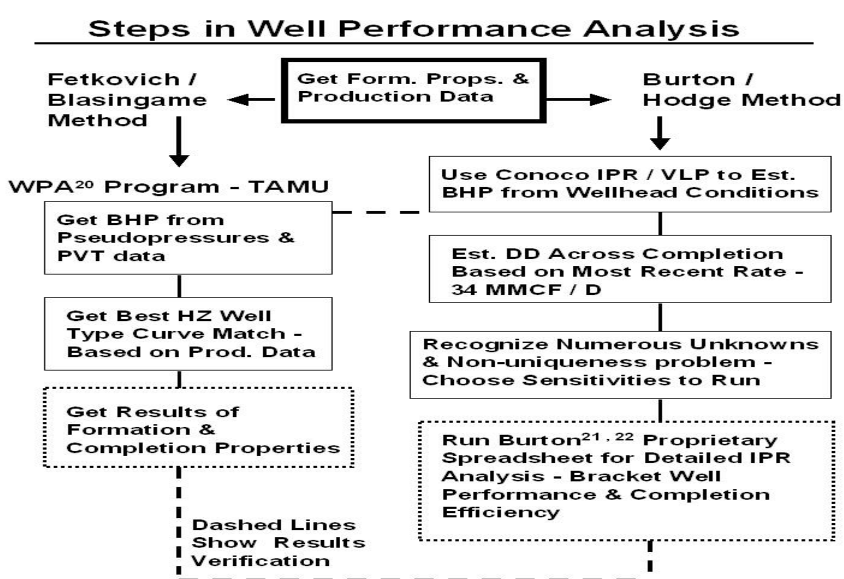
CHAPTER 6

Well Audits

Rationale for Well Audits

Well Audits evaluate the practices used to drill and complete horizontal, openhole wells.. A well audit represents a continuation of the work performed to identify the causes of formation damage in DIFs and with efforts to improve those fluids.. In the first phase of this project, laboratory work was completed to study the most important parameters in drilling and completing openhole horizontal completions. This portion of the study applies the knowledge gained in the lab to actual case studies. It has included (1) a combination of laboratory work, (2) the monitoring of fieldwork where advanced well completion techniques have been applied, and (3) the performance analysis in wells where the techniques have used. Through the analysis of well files (correspondence, personal interviews, test analyses, and other related data), the auditor studies the development of the well from the initial well plan through its production phase. The audit is designed to show that improved drilling and completion techniques result in more productive wells.

The steps of a well audit were standardized over the course of our research and were developed into a flow chart shown in Figure 6.1.



Each well audit contains the construction practices used in drilling and completing horizontal, openhole well, focusing on the wellbore cleanup and drill-in fluid selection. We then perform production analysis on early production data from the audited wells to determine the degree of formation damage and the results of cleanup methods. Two types of well test analysis have been used, the Felker Vukovitch as modeled for horizontal wells by Blasingame et al and the Burton and Hodge analytical technique for estimating completion efficiency.

***Alpine Field, Alaska*:**

This study is to compare the practices used in a case study to drill and complete three horizontal, openhole wells in the Alpine field on the north slope of Alaska. This study is a continuation of the work performed in conjunction with CEA-73. In the first phase of CEA-73, laboratory work was completed to study the most important parameters in drilling and completing openhole horizontal completions. This portion of the study applies the knowledge gained in the lab to actual case studies. It has included (1) a combination of laboratory work, (2) the monitoring of fieldwork where advanced well completion techniques have been applied, and (3) the performance analysis in wells where the techniques have used. Through the analysis of well files (correspondence, personal interviews, test analyses, and other related data), the auditor studies the development of the well from the initial well plan through its production phase. The audit is designed to show that improved drilling and completion techniques result in more productive wells.

The main objectives were:

1. Audit wellbore construction practices used in drilling and completing horizontal, openhole wells in the Alpine field of Alaska, focusing on the wellbore cleanup and drill-in fluid selection

2. Perform production analysis on early production data from the audited wells to determine the degree of formation damage and the results of cleanup methods.

Using horizontal well decline type curve techniques, production data was studied to determine the degree of skin in each well. Results from the well test analysis are used to indicate if there was impairment in the wells, indicated by the significant skin. It is suspected that despite good planning practices, the formation damage is caused by: inadequate cleanup design, polymer degradation, mud handling/carbonate sizing. Furthermore, the possibility of removing substantial amounts of this damage using the current methods is doubtful. Moderate remediation might be possible with altered cleanup practices.

CHAPTER 7

Well Audits

Introduction

As petroleum reservoirs around the world are explored and produced, greater attention is given to developing more challenging and difficult reserves. New technology, like that used in drilling horizontal wells, replaces conventional methods to explore and produce such reserves. An application of such technology often involves the evolution and development that result in creating completely new procedures. While horizontal well technology has opened many new methods to explore and develop reservoirs, it also has increased the likelihood of formation damage. Operators have found that without the perforating techniques used in cased hole completions, open hole completions are very susceptible to near-wellbore damage and skin effects. Accordingly, many new and different techniques and fluids are being developed to minimize formation damage.

It is helpful, as new problems arise and are solved, to discuss these methods and compare the results. From this comparison a set of best practices can be developed to drill and complete open whole horizontal wells. In the comparison phase, various approaches to the problem, laboratory studies, and results are evaluated. During this process, the lab results and the results from the field are matched to further hone the best practices. Finally, one of the main ways to facilitate an industry-wide discussion of best practices is to form an industry-wide consortium.

In 1994, the Texas A&M consortium was formed to study the formation damage potential in horizontal wells, the development of new fluids to reduce formation damage in the horizontal section of the wellbore, and the methods used for wellbore cleanup. That study, Completion Engineers Association 73, led by Dave Burnett also set in place a mechanism for relating laboratory results to field application. Burnett's group, CEA 73, has for the past 7 years studied drill-in fluids, completion fluids, and solids handling to better understand formation damage in horizontal wells.

Review of A&M Studies on Horizontal Well Completion Practices

The work performed for CEA-73 began with a series of laboratory experiments. The current phase of incorporating the experiments' findings with actual case studies investigated in the well-auditing phase has followed the laboratory work.

Much of the work included in CEA-73 was ground-breaking experimental work that provided much needed background information about the technology emerging from horizontal well development activities. In the early stages of the study, Garcia[1] performed laboratory experiments to study and evaluate cleanup techniques and metallic screen plugging mechanisms in horizontal wells. Her work was important because it proposed the variables which most greatly affect horizontal well cleanup: chemical composition of the drill-in fluid (DIF), weighting and bridging agents, particle size distribution, drill solids composition, and composition of the drill solids. It also showed that the degree of plugging and ultimately lift-off pressure needed to remove the filtercake was related to the size of the coarseness of the fines that made up the filtercake. Jepson's[2] work on the degradation analysis of filtercakes formed by water-based drill-in fluids provided a detailed look at the stability of polymers under downhole conditions. His work provided an organized analysis of the then new DIF filtercakes. It further provided details necessary for analysis of polymer degradation issues in the Alpine wells.

Key to this audit was the work done by Serrano[3] and Gutierrez[4], who combined laboratory testing and statistical analysis to develop correlations to estimate regain permeability and breakthrough time in horizontal wells. In the pursuit of these correlations, they identified several of the more important variables involved in formation damage in horizontal wells. Their work showed that the regained permeability and breakthrough time of a well put on production is inversely related to the drill solids content. This work was later used by Lacewell[5], who applied the findings to a case study of a well completion in the Gulf of Mexico. The application proved successful and further extended the work's application to a new type of carbonate DIF and gave further support to other CEA-73 work on DIF cleanup performance.

Review of A&M Well Auditing Program

Once the first phase of CEA-73 laboratory work was complete, it was necessary to apply the knowledge gained to actual case studies through a nature field study that bridged the laboratory with the wells in the field. An audit of well files (correspondence, personal interviews, test analyses, and other related data), examined the development of the wells from the initial well plan through the production phase. The audit shows that improved drilling and completion techniques result in more productive wells.

A continuation of the work begun by Lacewell established procedures for preparation and maintenance of DIF system. This study has been a combination of laboratory work with the monitoring of fieldwork, where advanced well-completion techniques have been applied, resulting in a performance analysis in wells. The research program studies the application of the technology developed through laboratory experiments to the extremely challenging environment, of the North Slope of Alaska. Using methods similar to those of the Lacewell audit, it reviews the effect of these technological applications upon the practices used in drilling and completing three open hole horizontal wells in the Alpine Field. As a result, this study provides a better understanding of which design parameters are important in controlling horizontal well performance. With these parameters identified, it establishes a series of best practices for industry use in drilling and completing open hole horizontal wells.

Objectives of the A&M Well Auditing Research Program

The main objectives of this research are:

1. Audit wellbore construction practices used in drilling and completing horizontal, open hole wells in the Alpine field of Alaska, focusing on wellbore cleanup and drill-in fluid selection

2. Perform production analysis on early production data from the audited wells to determine the degree of formation damage and the results of cleanup methods

This project offers a new approach to designing and implementing a horizontal well program by applying the latest technology. Burnett's[i] group states with no equivocation that "good well construction fluid design results in good well performance". Accordingly, this research program focused on the design, construction, and completion of a select group of wells from the perspective of well fluids' design and performance.

Selection of Phillips Alpine Field for Well Audits

This well audit investigates Phillips Petroleum's approach to drilling and completing open hole horizontal wells in the Alpine field of Alaska resulting in greater industry understanding and knowledge transfer. The efficacy of applying the technology and good drilling and completion practices used in this field demonstrates effective and ineffective practices in planning the wells. This audit further compares results of the laboratory studies with results from actual field experience. This comparison will improve open hole horizontal technology industry-wide as well as provide Phillips with insight that may help in future projects.

Procedures

Selection of the Wells

Three wells were selected for comparison in this study. The selection process placed emphasis on choosing wells that were all completed into the same zone or very similar geological setting. Controlling the zone of interest ensured similar characteristics such as temperature, pressure, and mineralogical makeup in a controlled experiment in construction and completion methods alone could be compared. All wells studied in this report were drilled into the Stillstand unit of the Alpine Formation. The Stillstand was selected because it showed the greater damage when compared to the Transgressive sand and it will be the primary target for the remaining wells drilled at Alpine.

Well Audit Data Collection

The success of the well audit phase relied greatly upon the quality and availability of the data from operators in the petroleum industry. From the literature search, field experience, and the objectives of this project, we compiled a survey of companies who volunteered data for the CEA 73 study. The survey sought information on all aspects of the project, from the early development of the prospect in geology and geophysics through the planning and execution of the drilling program to the planning and execution of the completion and production of the well. Acknowledging that some of the data requested were confidential or unavailable, the survey requested that as much data be released as possible. The requested data was broad and inclusive to ensure a clear understanding and proper evaluation of the program.

Well Audit

With the data collection for the three wells complete, the auditing process of the research began. Each well was first individually studied, from the initial planning stages through the production analysis. In the design phase of each well, it was important to determine what the designers knew and assumed about the project and what measures they had taken to develop a plan to accommodate these initial conditions. The recognized areas of concern were the methods used to select the drill-in fluid, steps taken to reduce formation damage, the considerations in developing a plan for wellbore cleanup, and the evolution of the overall wellbore construction plan.

Well Performance Analysis

The production data from the selected wells was analyzed to give a quantified analysis of the formation damage and ultimately the efficiency of wellbore cleanup. The analysis used Blasingame[6] and Shih's Well Performance Analysis, software which is based on the Fetkovich /McCray radial flow type curve method, modified for horizontal wells. Unlike conventional type curve analyses, which are based on a vertical well model or vertically fractured model, WPA is based on a derived line source for a horizontal well from the point source solution. In the model for the horizontal well type curves used in the program, the well is assumed to be located in the center of a square reservoir. The reservoir model assumes isotropy in the horizontal plane, single-phase flow in the reservoir, no gravity forces, and permeability independent of the reservoir location.

WPA requires several well parameters to be entered (Appendix), for calculation of dimensionless rate and time.

Geology

Geology is a critical factor in field development and well planning activities. Often overlooked, geology and its interpretation can make a significant difference between a well-planned program and a program that repeatedly makes the same mistakes in planning and execution.

Significant attention was paid to the geology of the field when planning operations at Alpine, as evidenced by the several geological studies completed before and during the field's development. Many lessons were learned in the development of other North Slope fields, and there were several in-depth studies made to study the geological environment during the early development of the field. Among the studies conducted were several x-ray diffraction studies and petrophysical analyses. These studies were relied upon in virtually all phases of development, from selecting the drilling fluid and completion fluids to designing the most effective and efficient stimulation procedures. The mineralogy and description are particularly important to determine rock/fluid compatibility and to make lithologic comparisons between reservoir rock of different fields, which is important in comparing the efficacy of different techniques.

Well Test Analysis

The well test analysis and skin calculations are means of interpreting quantitative data to determine the degree of damage to the well and measure the efficacy of the well planning procedures.

Base Study

Production analysis for this study used Well Performance Analysis (WPA) an analysis suite based on the Fetkovich/McCray radial flow type curve method and modified by Blasingame and Shih for horizontal wells. The software uses early-time production data to characterize horizontal well performance. It calculates and subsequently matches the rate functions, production rate integral, and integral derivative plotting functions. It then plots these data on the best horizontal well type curve, which is selected on the basis of the penetration ratio and dimensionless wellbore radius.

The data for each of the three wells were production data gleaned from the weekly production reports. Data from two of the three studied wells, 40 and 43, could be analyzed and matched. The type curves are seen in Figs. 3 and 4. A summary of the results are included in the Table 4 below.

Table 4 Results of Production Analysis Using WPA

Well	OOIP, MSTB	Areal Extent, acres	Effective Permeability, md	Effective Horizontal Length, ft	Actual Length, ft	Flow Efficiency
40	9.841E+04	1510	2	811	3396	24%
43	1.215E+05	1760	4	876	2716	32%

Comparing the two wells, the areal extents are close. Effective permeability calculated in the analysis is not necessarily similar to that of the log permeability. The flow efficiency calculations of these production analyses' calculations indicate significant formation damage. The flow efficiencies, which are the ratio of the calculated well length to the actual well length, to indicate the percentage of the wellbore that is contributing to production, are quite low.

Sensitivity Analysis

To test the validity of the analyses, the analysis used pessimistic results given of the base study. I modeled reservoir thickness, compressibility water saturation, and porosity, with the thickness of the reservoir held constant in WPA. Phillips[7] believes that the top of the Alpine formation is marked by an unconformity and that it has a relatively flat, uniform top. Although the bottom is more variable, it, too, is expected to be a gradual. we assigned, the thickness an overall prediction accuracy of +/- 10%. In developing a sensitivity analysis, we varied the well length by 10%. Thickness proved to be an important variable in determining the effective length, permeability, and drainage area. The likelihood of the formation compressibility varying significantly in the reservoir is small, but it has a meaningful impact on the results. Water saturation has no real impact on the analysis, but it shifts the curve to the left or right, without affecting the calculations. Like water saturation, porosity had little effect on the matches.

The tested wells showed significant damage. Sensitivity analysis supports the view that the input values were realistic.

4.2.3 WPA Observations

The WPA analysis is hampered by the quality of data. In Wells 40 and 43, with minor editing, data sets were available for production analysis. The data for Well 41, however, were too random to attempt reasonable editing for analysis.

Production data should be taken on a regular basis, with the intent of collecting data for future analysis but current data from Alpine are a by-product, gleaned from the

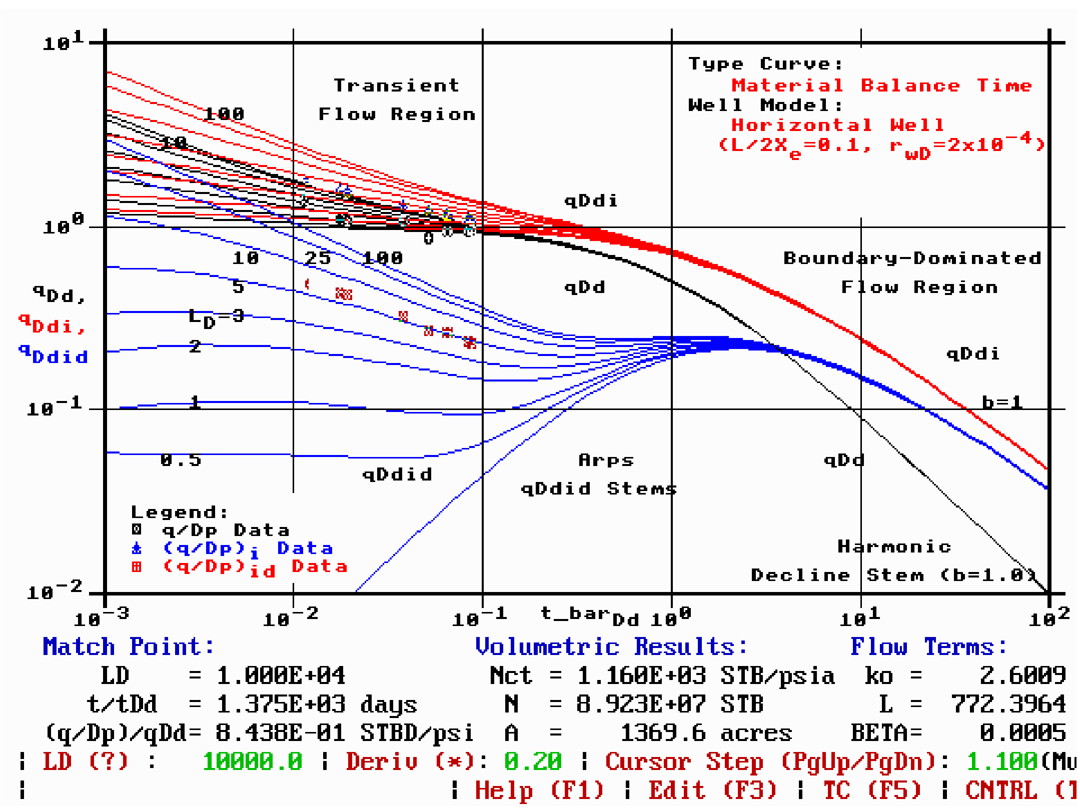


Fig. 4 Production Analysis of Well #43

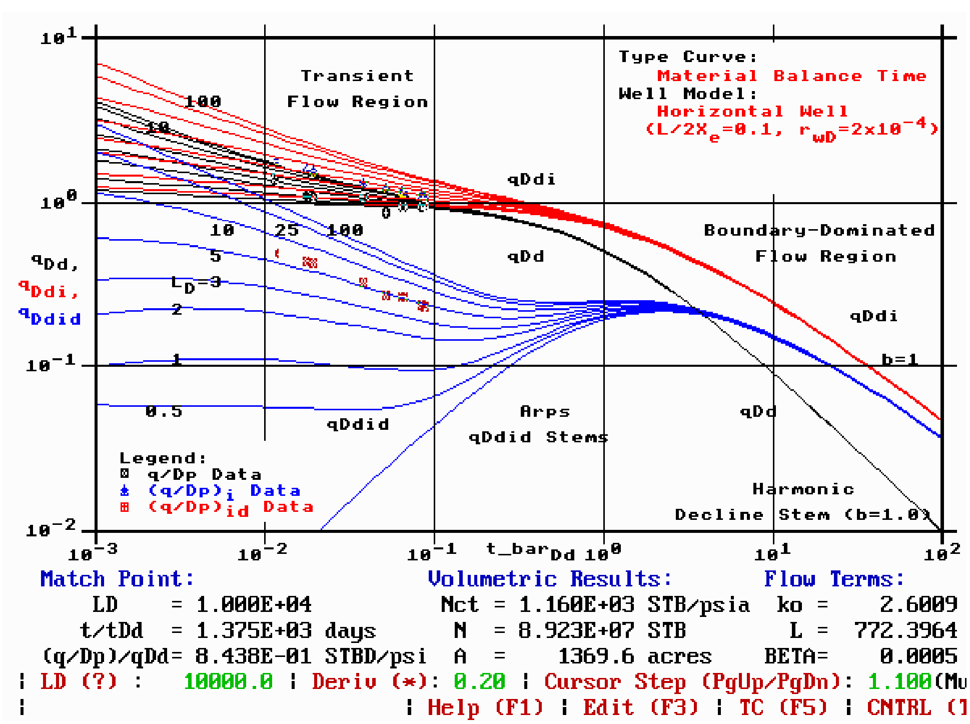
production reports. The lack of quality downhole pressure data required the analysis to be based on the separator pressures collected at the surface. As a result, the pressure data do not include the hydrostatic head of the fluid column, nor do they represent the downhole conditions as well as consistent bottom hole pressures.

Analysis of Results of the Formation Damage Study

A number of factors may have contributed to low performance indices in these wells. The Alpine formation mimics that of the Kuparuk C. Kuparuk C was drilled and put on production, with few problems, once the acid problems were solved. Water blocking should theoretically be the same in Alpine as in Kuparuk C. The difference between Kuparuk C and Alpine is not clear, other than the delay in cleanup.

Some means of minimizing formation damage include:

1. Control fluid loss and spurt loss. Values should be as low as possible
2. Ensure filtrate compatibility. In water-based muds, the water chemistry of the filtrate and the formation water should be studied to ensure that scale will not precipitate. Wettability should be considered as a source of damage--a stable, low-surfactant system should be developed
3. Minimize mud solids invasion. Particle size affects the DIF ability to plug and bridge pores; knowing the pore size distribution allow for appropriate formulations of DIF.



4.4 Possible Culprits

The proposed causes of the formation damage, ranked in the order of their significance are as followed:

1. Polymer degradation/filtercake deterioration over extended time period
2. Inadequate cleanup plan
3. Mud-handling practices
4. Particle/polymer invasion (carbonate sizing)
5. Bacteria/biocide treatments
6. Water blocking

4.4.1 Filtercake Deterioration-- Filter Cake Remained in the Hole Too Long

Filtercake deterioration is a suspected cause for the formation damage incurred in the wells at Alpine. The data presented in this case study suggest possible filtercake degradation. Though little research has been done in conjunction with this hypothesis, it bears further research. Sharma *et al*. stated that the greatest source of damage to an open hole horizontal completion is not particle invasion, but rather polymer invasion. Experience in the A&M research program, suggests that the filtercake underwent a transformation to a material that could not be readily removed by drawdown when the well was not on production.

Summary of Formation Damage

A great deal of outside analysis and laboratory work has gone into the evaluation of formation damage in the Alpine Field. Many theories have proposed many different answers for the damage. Through an exhaustive literature search, a review of these past studies, and research, the following six causes of formation damage were investigated: polymer degradation, poor cleanup plan, mud handling, particle/polymer invasion (carbonate sizing), bacteria/ biocide treatments, and water blocking. The problem seems to be a time-sensitive issue, as the geology of Alpine and Kuparuk are similar but have cleaned up differently. This leads to the idea that the polymer mudcake that was left downhole during the shut-in period has not cleaned up as expected. Further research in the area is needed to study this phenomenon and determine if the hardening is a reaction to downhole reaction to temperature or whether it has been caused by reactions with ions left in the wellbore. Contributing to the formation damage are a "tentative" cleanup plan and mud handling, particle/polymer invasion (carbonate sizing), and bacteria/ biocide treatments. These contributing factors were ranked based on their likelihood of occurring and causing damage to the wellbore.

Water blocking, using the information from Bennion's papers in conjunction with the well data does not seem to be the main culprit of the damage as suspected in the past. The calculations do not support its ability to cause the dramatic effects observed. If additional investigations of water blocking are planned, they should be performed in the Phillips Laboratory using the advanced technology relative permeability core testing services.

Conclusions

The following can be concluded about the Alpine open hole horizontal well study:

1. Good planning was used in the Alpine horizontal well program. Throughout the program, state-of-the-art technology was considered, researched, and applied.
2. Well performance analysis performed on the studied wells indicates significant wellbore damage. Flow efficiencies of only 24 and 32% were calculated from the two well analyses.
3. Despite good planning practices, there is evidence of formation damage caused by a combination of the following, listed in order of likelihood:
   a. Inadequate cleanup design
   b. Polymer degradation
   c. Mud handling/carbonate sizing
4. The possibility of removing substantial amounts of this damage using the current methods is doubtful. Moderate remediation might be possible with altered cleanup practices.

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CHAPTER 8

Results and Conclusions

Characterizing Formation Damage in Openhole Completions

This research presented experimental work to evaluate plugging mechanisms and cleanup techniques to remove the filtercakes before installation of production screens in horizontal wells. Tests used the Poroplus™ metallic screen and evaluated two existing DIF's with added drill solids. Both developed impermeable filtercakes that varied dependent on the simulated drill solids. The evaluations focused on PSD, concentration, and composition and their influence of the physical and chemical removal of the filtercakes from the unconsolidated core before they were backflowed through two screen slot widths.

The insights gained from the characterization of filtercakes can be summarized as follows:

1. The cleanup of the filtercakes is a function principally of the chemical composition of the DIF, weighting and bridging agents, drill solids concentration, particle size distribution, and composition of the drill solids.

2. Bridging and weighting materials make up a significant fraction of the DIF's and even more of the filtercakes and have marked influence on the strength and the permeability of the filtercake developed by water-based SCC and SS.

3. The presence of clay as drill solids in the SCC filtercake reduced the initial particle size distribution of the bridging and weighting material. The percentage of the ultrafine material was substantially increased, causing a reduction in the median size grains, which decreased even more the paths into the filtercake. Clay also hinders effective contact between acid and the BWM particles, and reduces its potential for total dissolution.

4. A decrease in the particle size decreases the plugging of the screen. Increasing the level of suspended solids able to get through the screen with a consequent reduction in the particle size to be retained increases the probability of the screen to be plugged.

5. SCC seems less damaging than SS, as a consequence of the MDP. The high MDP reached during the dislodging of the SS filtercake seems to favor the encrustation of a large amount of solid material into the screen slots, which further reduces the screen permeability and the flow capacity of the system (core/screen).

6. A comparison between the dissolving power of the 5% and 15% HCl indicates that the sodium chloride is more soluble in the HCl acid than the calcium carbonate under the same conditions of temperature and acid concentration, taking into account the stoichiometry of the reaction of the compounds. Therefore, filtercakes formed by SS DIF containing clay and sand are more soluble in HCl than those formed by SCC containing the same drill solids.

7. The presence of drill solids affected SCC cleanup more than SS systems.

Field Results and Correlations with Model

The rationale for well audits came from the realization that many laboratory tests do not reflect actual field conditions. We believed that coupling lab results to field results would help to avoid this problem. We therefore designed a series of field trials to correlate the laboratory results to field experiments. The well audit programs included the following:

Gulf of Mexico horizontal completion
North Slope Alaska horizontal well completion
North Sea horizontal well completion
Gulf of Mexico horizontal well completion (polymerfree DIF)

The well audits were conducted by members of the A&M group with the approval of the operators and service companies who drilled and completed the wells.

The well audits showed that high quality DIFs were associated with high performance wells. The North Slope well met production targets despite having to meet strict operating standards required by the harsh environment. Lessons learned from that study include:

1. Good planning throughout the program resulted in good well performance.
2. Despite good planning practices, there is evidence of formation damage caused by a combination of the following, listed in order of likelihood:
    a. Inadequate cleanup design
    b. Polymer degradation
    c. Mud handling/carbonate sizing

The 1998 Gulf of Mexico well produced at rates two to three times higher than offset wells in the same production interval. The well drilled with polymer free DIF exceeded all expectations.

When DIF quality standards were not met, operational problems ensued and well performance was less than expected. A North Sea well whose drilling program had difficulty keeping DIF quality high had to be abandoned and a side track drilled.

There are two main recommendations for future work involving well auditing practices. First more well audits should be performed. They provide a valuable post mortem record of events that serve as guidelines to future practices. Next they provide a valuable reference to show how laboratory methods can be translated into field results.

The second recommendation for well auditing function is to streamline auditing practices so that less time is required to compile a meaningful record.

New DIFs for Low Damage Completions

<u>Low Solids Carbonate DIFs</u>

The research conducted has helped to pinpoint the importance of the concentration of solids in the DIF. Bridging solids should be kept las low as practical, just as drill solids concentration should be kept at low concentrations. The new formulations for DIFs now being offered in the commercial market acknowledge this fact. Not only does the well completion have a better chance of performing at its maximum rate, the DIF itself is less difficultto manage, YPs and are easier to manage, and rehological characteristics of the system are better than with a high solids system.

Polymer Free Systems

The reactivity of HCl acid with DiPro system is too reactive at high temperatures (160°F or above) and high acid concentrations. This reactivity causes difficulties in getting complete coverage required for adequate filtercake cleaning. Our tests show that the use of HCl at low concentration (2%) is adequate for low temperature applications (110°F). Return permeability expected could be around 50%.

The use of weak acids such as acetic acid to clean up DiPro systems results in more favorable reactivity times but the cleaning could be non-homogeneous producing a pin-hole pattern. Due to this, some areas could be very well cleaned while other areas are missed. The final results in terms of return permeability can be difficult to determine.

More definitive conclusions on DiPro performance will come from the analysis of field data from wells where the product has been used.

Low Density Systems

Low density DIFs offer an effective means to drill productive intervals with minimal formation damage. The tradeoff between low density and fluids containing fluid loss additives and be altered significantly if a portion of the bridging solid material is composed of low density material. Our research has shown that the HGS systems offer an attractive alternate to other types of DIFs as long as total DIF solids do not exceed certain limits. The new LDDIF formulation offers the following advantages:

- HGS systems offer weight-reducing solid additives that are inert, help in well cleanup and are environmentally acceptable.
- HGS fluids behave like standard drilling fluids..
- HGS fluids cause less formation damage than fluids without HGS.
- Breakthrough time of HGS fluid is much less than fluid without HGS. Post-breakthrough flow rates indicate indicate improved cleanup.
- There is no significant difference in permeability regain between HGS fluid and non-HGS fluid.

Acronym's

ADX-Automated Design of Experiments

BWM-Bridging & Weighting Material

CEA-Completion Engineering Association

CF- Completion Fluid

DIF-Drill In Fluid

DOE-Department of Energy

HAC-Acetic Acid

HGS-Hollow Glass Sphere

LCM-Loss Control Material

MDP-Minimum Dislodging Pressure

NETL-National Energy Technology Laboratory

PSD-Particle Size Distribution

SCC-Sized Calcium Carbonate

SEM-Scanning Electron Microscope

SS- Sized Salt

Nomenclature

A_{core}	= Area of core, cm^2
BT	= Break through Time, min
D_p	=Formation pore size
DS	= Drill Solids, weight %
HCl	= Acid concentration, volume %
k	= Formation permeability, md
K_i	= Initial core permeability, d
K_f	= Final core permeability, d
L_{core}	= Length of core, cm.
ΔP	= Differential pressure, psi
Qn	= Flow rate, cc/sec
RP	= Regain permeability, %
T	= Temperature, °F
μ_w	= tap water viscosity, cp