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Everything You Wanted to Know About Clay Damage but Were Afraid To Ask

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Abstract

This paper provides a basic reference for clay description, clay/fluid interaction, clay stabilization, and clay/fines migration. The three types of clay stabilization including ion exchange, coating of clay particles, and modification of surface affinity toward water are described in detail. The evolution of the “7% KCl rule” is discussed, and the effect of pH on clays is investigated. The damaging potential of destabilized or migrating clays is illustrated by considering the volumetric and surface areas contacted by typical stimulation treatments.

Traditional methods to test for clays using X-ray diffraction (XRD), scanning electron microscope (SEM), and coreflooding are discussed. The challenges faced when using this testing in unconventional reservoirs and the impacts of using drill cuttings are described. The drill cuttings testing method is illustrated along with the recommended testing frequency throughout a play.

Ranges of clay type and amounts are given for various shale and tight-sand formations in Oklahoma. An example of clay content is presented that illustrates the variability and distribution of clay material in a single formation. It is concluded that most formations in Oklahoma have a significant amount of clay material, which can vary dramatically within a formation. The potential for clay damage is significant even in low-clay-content formations; however, clay damage can be mitigated through new testing methods, proper clay characterization, and the use of clay-control additives. This paper attempts to determine how much clay is “too much” and what type of clay stabilization is appropriate based on drill cuttings clay-control testing.

Introduction

Clays are present in a majority of hydrocarbon-bearing formations, and their presence can cause problems in the production of oil and gas.

Clays can be found in all types of rock. Such rocks or formations have been called “water sensitive” and may be defined as a formation that exhibits a reduction in permeability when foreign water invades the pore space. Sandstone formations exhibit the greatest degree of water sensitivity. Clays are present in carbonates but are frequently encapsulated in the rock.

Clays are hydrous aluminum silicates. In some clays, magnesium or iron substitute in part for aluminum, and alkalis or alkaline earths may be present. Although clay may be made up of a single clay mineral, they can be mixed with feldspar, quartz, carbonates, and micas.

“Most oil- and gas-producing formations contain clay minerals that either were originally deposited during sedimentation (detrital clay); were formed later by the action of heat, pressure, and time on minerals already present; or were precipitated from fluids flowing through the matrix (authigenic clays).

The importance of these minerals in oil and gas production and their potential permeability damage has been investigated widely. The two major mechanisms by which these minerals cause permeability damage are swelling and migration. In swelling, clay imbibes water into its crystalline structure and subsequently increases in volume, plugging the pore in which it resides. In migration, clay minerals can be dispersed by contact with a foreign fluid or can be entrained by produced fluids and transported until a restriction is encountered (usually a pore throat), where the entrained particles bridge and restrict flow in the capillary. The migration of clays and other fine minerals has also been explored extensively.”[1]

Description of Clays

All the clays mentioned above are flat crystals. They exist as thin platelets that are normally stacked like a deck of cards. Stacking is not necessarily even as platelets can overlap in the packets.

All clays are negatively charged. The negative charges are predominant on the face of the clay. Density of the negative charges can be measured by determining the number of positive charges required to neutralize the crystal. This is known as the cation exchange capacity (CEC) of the clay and is expressed in milliequivalents (ME) for 100 grams of clay. Examples of CEC values for minerals are presented in **Table 1..** Because of this negative charge cations, such as potassium, calcium, and ammonium are attracted to the negative sites. This restricts the absorption of additional water between the crystals. However, if the potassium ions are replaced by a supply of sodium ions from formation water, the clay will return to a state in which it can swell if some relatively fresh water invades the vicinity.

Table 1—CEC

Mineral	CEC
Smectite	80 to 150
Illite	10 to 40
Kaolinite	3 to 15
Chlorite	10 to 40
Quartz	0.6

The clays under consideration may be classified as swelling and non-swelling. Montmorillonite is the only clay that swells by absorbing water layers between clay crystals. Mixed-layer clay, which contains montmorillonite, will also swell. Kaolinite, chlorite, and illite, may be classified as non-water-swelling clays. Yet, they do absorb some water.[1,2]

Kaolinite is commonly known as "china clay" because of its use in ceramics. A SEM image of kaolinite is shown in **Fig. 1**. It is a secondary mineral formed by weathering of aluminum silicates, usually feldspar. It is a two-layer clay composed of a layer of cristobalite (SiO_2) and a layer of gibbsite ($Al_2(OH)_6$). It can resemble a pile of coins. Kaolinite swells very little in water; however, it can migrate.

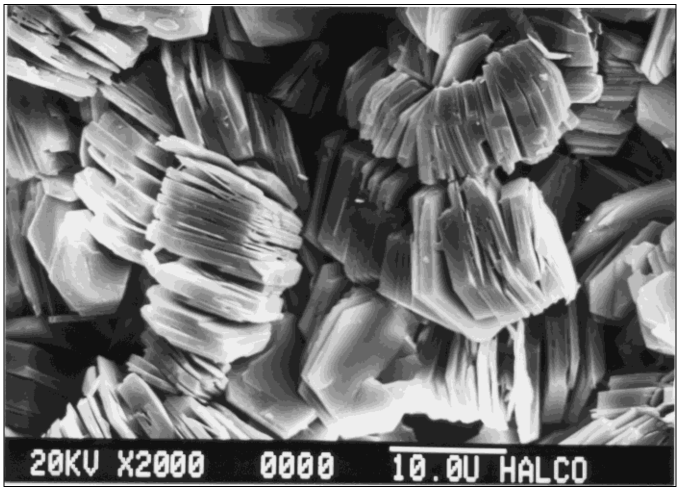

Fig. 1—A SEM close up of kaolinite.

Illite is actually the name of a group of clay-like minerals that contain potassium. A SEM image of illite is shown in **Fig. 2.** It is a general term for mica, glauconite-like clay material. The illites differ from mica in having less substitution of aluminum for silicon. Also, they contain more water and have potassium partly replaced by calcium and magnesium. Illite is the major component in many shales. It is not water swelling but is a migrating clay.

Fig. 2—A SEM close up of illite.

Smectite or montmorillonite is composed of a number of clay minerals composed of tetrahedral-octahedral-tetrahedral silicate layers. A SEM image of smectite is shown in **Fig. 3.** Its characteristic is the ability to absorb water molecules between the sheet layers, causing large expansion of the structure. Montmorillonite is the dominant clay mineral in bentonite.

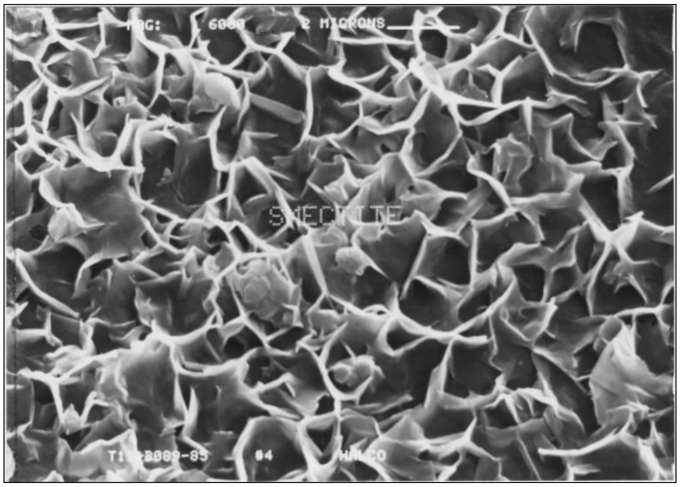

Fig. 3—A SEM close up of smectite.

Chlorite has a green color. An SEM image of chlorite is shown in **Fig. 4.** It comes from igneous rocks where it has formed as an alteration of magnesium-iron silicates. It is an iron-rich three-layer clay. In acid solutions, the removal of iron from the layers results in a silica-rich amorphous material.

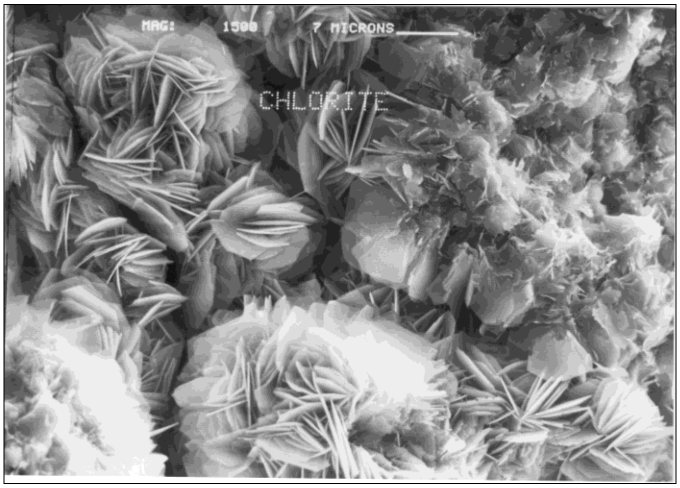

Fig. 4—A SEM close up of chlorite.

Mixed layers are primarily illite-montmorillonite, kaolinite, and chlorite. A SEM image of mixed-layer clays is shown in **Fig. 5.** It is water swelling and can have additional problems associated with chlorite when in an acid environment.

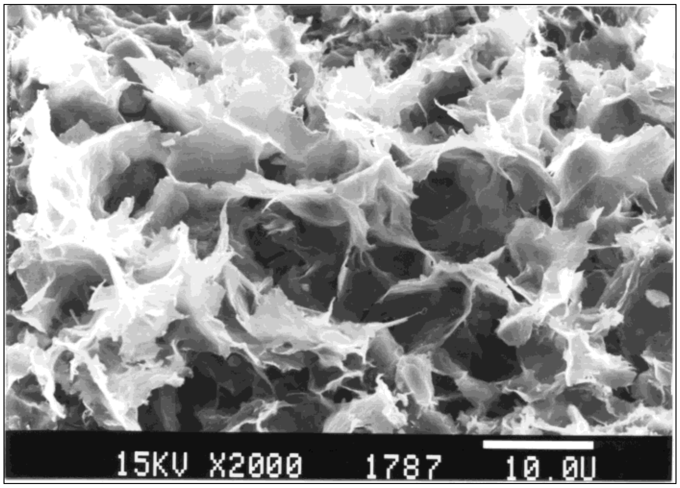

Fig. 5—A SEM close up of mixed-layer clays.

Zeolites are a class of alumino-silicates, which include analcime, heulandite, natrolite, stilbite, and clinoptilolite. They have a high ion exchange and are unstable in HCl.

Hectorite is a member of the montmorillonite group. In this clay, magnesium has completely substituted for the aluminum in montmorillonite. It is both water swelling and migrating.

Siderite is called clay ironstone. It is formed by replacement action of iron-rich solutions on limestone.

Mica is a potassium-containing clay. Examples include muscovite and biotite, which are fairly unstable in HCl.

Damaging Potential of Migrating Clays

How Much Clay is Too Much?

When should clay content become a concern? In the mid-continent area, clay content can range from 3% to 30% based on X-ray analysis. The average falls between 5 and 15% by volume. While 5 to 15% by weight does not sound like a large amount, if all the clay material resides in the pore volume of the rock, there may be little room for permeability.

Usually pore volume is 10% (ϕ=10%) or less of the total rock volume.

Put another way, if there is a porosity of 10% and 8% total clay by weight from X-ray analysis, then it follows that for each 1.0 ft^3 of rock there is:

- 0.1 ft^3 of void space
- 0.9 ft^3 rock or 180.94 lb (assumes 2.65 g/cm^3 sandstone)
- 8% of 180.94 lb is 14.47 lb of clay

Assuming 0.006 lbm/ft^3 absolute volume clay, then clay volume = 0.0868 ft^3.

If all of this clay exists in the pore space (0.1 ft^3), then 8% clay is occupying 86% of the pore space volume. In cases when clay content is higher than porosity, and permeability still exists, the clay content must be associated with the rock matrix or cementing material holding the grains together.

But does clay in the pore space mean the formation is damaged? It may not be damaged if the clay is stable or the reservoir flow is capable of moving this solid out of the formation, up the wellbore, and into the stock tank. If not, the clay will accumulate in the pore throats, and a gradual reduction in permeability will result.

How Much Fines is Too Much?

Almost everything operators do to a productive zone, including drilling through it, cementing casing across it, perforating it, and pumping stimulation fluids into it can cause damage. Movement of produced fluids themselves can cause damage by mobilizing fines.[5]

The near-wellbore region is the collection point for formation damage due to foreign fluids being injected, and the migration focus point during production. Flow convergence occurs near the perforated interval as shown in **Fig. 6.**

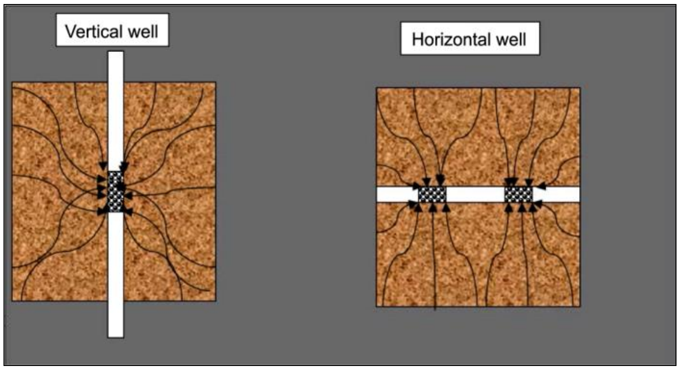

Fig. 6—Flow convergence that occurs near the perforated intervals. The image on the left is an example of flow convergence in a vertical well, and the image on the right is an example of flow convergence in a horizontal well.

It is important to note that most formation fines are not clay minerals. Muecke[3] shows that on average, clay represents only 11 wt% of the total fines generated.

Fines Composition Breakdown[4,5,6]

- Quartz = 39%
- Amorphous material = 32%
- Feldspar, muscovite, calcite, dolomite, barite = 8%
- Clay = 11%
- Particle sizes 37 μm to 1 μm; 37 μm will pass through a 400-mesh screen.

But how much fines migration does it take to damage a well? The following is an example using oilfield numbers.

If a 30-ft net-pay well with a moderate size fracturing stimulation treatment creates a 100-ft gross height, 300-ft half length, and 0.5-in. width at the wellbore, then the area of pay, which is exposed to frac fluid and formation fluid flow is $\pi \times 15$ ft$\times 300$ ft$\times 2 = 28{,}274$ ft^2.

Total area of exposed rock pay + barrier rock is $\pi \times 50$ ft$\times 300$ ft$\times 2 = 94{,}248$ ft^2.

Using 0.5-in. width at the wellbore, the average frac width is 0.25 in. and the volume of the fracture is 1309 ft^3. This assumes little or no leakoff of the fluid and the entire volume of the frac is filled with proppant (±1309 sacks).

Disregard any fines migration from the non-pay area into the newly placed prop pack. Further, assume proppant is placed with a zero residue fluid; thereby, the entire proppant pore space is available for flow or fines accumulation. Also assume the proppant does not crush, and the proppant pack void space is approximately 30% or ϕ=30%.

This indicates approximately 392 ft^3 of total proppant void space available. While this sounds like plenty of room for fines migration and accumulation, remember the choke point is along the length of perforated interval as shown in **Fig. 7.**

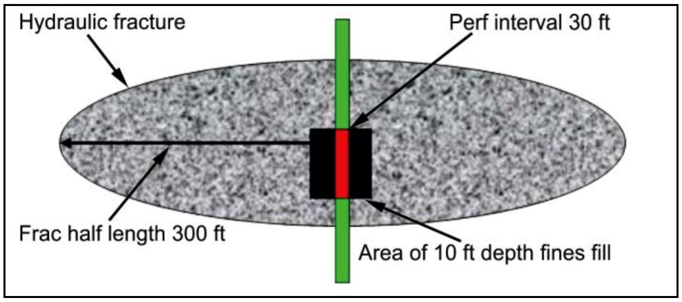

Fig. 7—The fracture area vs. the perforated interval (vertical well).

If assuming the well would be severely damaged by a 10-ft depth of fines-filled proppant pack near the wellbore across the perforated interval, then for a bi-wing frac with width of 0.5 in., the prop void space along the 30-ft perforation height and out 10 ft is only 4 ft^3 of prop void space. If this volume was completely filled with fines using bulk volume of bentonite at 60 lbm/ft^3, then ± 240 lb of material will completely pack off a 30-ft vertical in the near-wellbore proppant pack to a depth of 10 ft in each frac wing.

For horizontal wells with transverse multiple fractures, the choke flow path is even more restricted as shown in **Fig. 8.** For a typical cluster length of 2 ft, the amount of fine material to plug the fracture connection to the wellbore may be less than 30 lb. While the above calculations and estimates are simplistic, they do illustrate the scale and magnitude of the process.

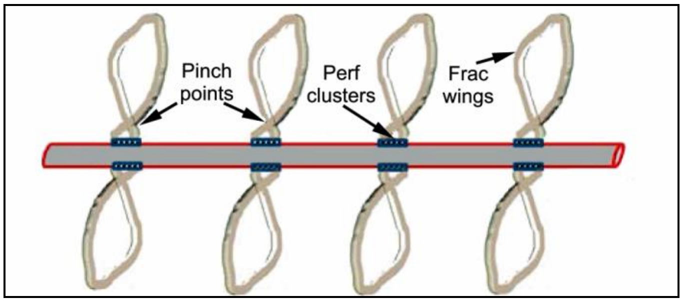

Fig. 8—Horizontal well with multiple transverse hydraulic fractures. Perf cluster length 2 to 3 ft. Fractures start out longitudinal along the wellbore, then turn 90° to align with σ_{max}.

Potential Clay Contact with Frac Water in Tight-Oil and Gas Plays.

Clay damage from injected frac fluid was first discussed in high-permeability zones in which fluid penetration of the pore volume around the wellbore was large.

Traditional Testing Methods for Low-Permeability Formations

Standard core flow tests for clay swelling and migration are not possible unless the formation permeability is more than 1.0 md. Almost all formations presently being drilled in Oklahoma are in formations with permeability less than 0.1

md. Obviously, most “unconventional shale” plays are well below 0.001 md. This presents a problem when determining the degree of potential clay damage expected from treating fluid injection.

X-Ray Diffraction Analysis of Mineral Solids (XRD Spectroscopy)

Crystalline solids have an organized arrangement of atoms in three dimensions. X-rays have wavelengths in the same range as the spacing of atoms in these crystalline solids. Unlike visible light, when an X-ray beam is projected onto a crystalline solid, the X-rays will diffract or reflect only at certain angles. These angles must obey Bragg’s law.

$$2d \sin\theta = \lambda n \tag{1}$$

That is, for X-rays of a single wavelength, there is only one angle for a particular spacing between atoms where they will reflect. Since in each mineral there are atoms of different elements in numerous spacing arrangements that each produce a reflection, a diffractometer is used. This instrument allows for varying of the angle of the X-ray beam and measuring at which angles the beam is reflected for that sample. The resulting XRD pattern is then compared to the patterns of known mineral(s) to determine the mineral composition. Quantitative measurements can be made based on the relative intensity of strength of the reflections for each mineral present.

Immersion and SEM

Immersion of samples and a before and after SEM picture may tell how stable the rock is in the presence of various solutions.

Visual (SEM) location of clay material is shown in **Fig. 9.** This example illustrates how the kaolinite particles have filled in the pore space of the samples, thus limiting the flow through the pore space.

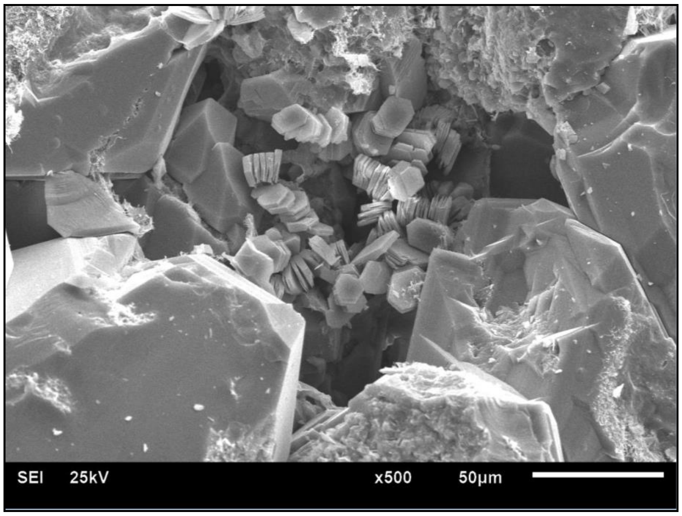

Fig. 9—This SEM shows kaolinite particles fill in the pore space of a formation.

New Testing Methods for Low-Permeability Formations

Custom Clay-Control Service

The custom clay-control service assesses formation samples for clay stability with proposed stimulation fluids. Formation compatibility with stimulation fluids is imperative to ensure the maximum longevity and production efficiency of a well. This service provides a workflow designed to evaluate formation materials for potential clay-associated damage mechanisms, including swelling, sloughing, fines migration, and formation softening, which may cause increased proppant embedment. Any of these effects may contribute to loss of fracture conductivity or reservoir flow delivery across the fracture/reservoir interface. By directly monitoring the effect of clay stabilization products on formation samples, this new service workflow will output a clay treatment product recommendation as well as the recommended optimum treatment concentration.

On a well-by-well basis, this service offers customers detailed formation information and a performance-based, optimized treatment recommendation. The testing protocol is designed to be performed in field laboratories by trained personnel using two distinct methodologies: the swelling stability test (SST) and mechanical stability test (MST) to rank all of the possible treatments. The three-step process considers the well mineralogy and source water and then ranks the performance of the clay-stabilization products.

The SST measures the swelling tendency of formation materials in the presence of a treatment fluid. This is accomplished by measuring the degree of interaction between the formation material and treatment fluid with a calibrated standard measurement procedure. The SST is sensitive to both the treatment fluid ionic strength and the CEC of the formation mineralogy. The SST measurement for treatment fluid formulations can be compared to standards and assessed for relative merit.

The MST measures the softening, fines migration, and sloughing of formation material caused by mechanical destabilization in a fluid. Ground formation materials are subjected to different treatment fluids and mechanical agitation. In a short period of time, the propensity of the sample to disintegrate and release suspended fine materials is determined by a standardized process with easily interpreted measurements that facilitate ranking of treatment fluids.**.** Higher instability measurements are an indication that the fluid contact and flow simulation process resulted in an increase in the rate of formation destabilization.

Traditional Clay Stabilization Solutions

Almost every stimulation fluid pumped into a producing reservoir, with possibly the exception of pure N_2 gas or oil, will interact with the mineral composition of that formation. Recent work in reactions of formation minerals with HF and HCl acid solutions have shown that most minerals found in oil- and gas-bearing formations are affected by injected fluids. The following are excerpts from Gdanski (1997)[3], which summarizes these fluid interactions.

Silica (SiO2) is called quartz, sand, silica, or chert. Sands can be categorized by percentages of quartz as shown in **Table 2**.

Table 2—Categorizing Sands

90% to 100%	Clean sand
75% to 90%	Fairly clean sand
50% to 75%	Dirty sand
Less than 50%	Extremely dirty sand

Feldspar is an alumino-silicate but is not considered to be clay. Feldspars contain sodium, calcium, and potassium in their structure. Potential release and precipitation of potassium in HF-acid systems cause the most failures of typical HF-acid treatments. Feldspar can be categorized by either sodium or potassium as shown in **Table 3**.

Table 3—Categorizing Feldspar

Sodium feldspar	Albite, plagioclase
Potassium feldspar	Orthoclase, k-spar, microline

Carbonates are usually calcite and dolomite. Others are mixtures of calcium, magnesium, and iron. It is the carbonate content of sandstone that causes concern about precipitation of calcium fluoride, fluosilicate, and aluminum in HF-acid systems. Carbonates can be categorized into four groups as shown in **Table 4**.

Table 4:Categorizing Carbonates

Calcite or Aragonite	(Ca)
Dolomite	(Ca, Mg)
Ankerite	(Ca, Fe)
Siderite	(Fe)

The different mineralogy in formations will react differently when exposed to fracture fluids. **Table 5**, provides a list mineralogy and the type of fluid interaction that are possible.

Table 5: Mineralogy and Fluid Interaction Table

Feldspar	Contains sodium and potassium. Major concern is fluosilicate precipitation. Potassium feldspars are the worst.
Carbonate	Consumes HCl and can cause precipitation of fluosilicates and aluminum from spent HF.
Illite	Fines migration problem, ion exchanging. Contains potassium, which can cause fluosilicate precipitation from spent HF.
Kaolinite	Fines migration problem. Disperses in fresh water and causes plugging.
Smectite	Ion exchange, swells in fresh water.
Mixed-Layer Clay	Ion exchange, swells in fresh water, may contain potassium, which can form precipitate from spent HF.
Chlorite	Ion exchange, unstable in HCl with no acetic.
Mica	Ion exchange, unstable in HCl, contains potassium, which can cause precipitation in HF.
Zeolite	Ion exchange, unstable in HCl, may contain sodium, which can cause precipitation in HF.

New Clay Stabilization Solutions

Clay can be stabilized three ways:

- Ion exchange (salts NH4+, K+, H+, Na+, Ca2+, Al3+, Zr4+)
- Coating of clay particles (COPs)
- Modification of surface affinity toward water (oil-wetting surfactants)

The impact of clay minerals on the production of hydrocarbons from sandstone formations has been a topic of investigation for many years with a variety of clay-control materials generated to provide solutions for many types of applications **(Fig. 10).** Yet, the industry provides little guidance on treatment selection and design.[7]

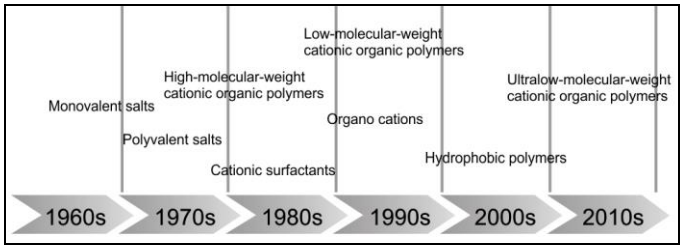

Fig. 10—Timeline showing major advancements in chemical control of clay minerals.

Many salts have been used to stabilize clays. These salts provide temporary clay stabilization. Jones (1964)[8] studied the water-sensitivity problem and concluded formation damage was the result of an abrupt change in salinity between the fluid saturating the formation and the injected fluid. Jones found damage could be prevented by the addition of salts to fresh water. It was shown that divalent calcium and magnesium salts were more effective than monovalent sodium salts, and it was recommended that 25 lb/1,000 gal (0.3%) of calcium chloride be added to fresh water when injecting into sensitive formations.

The addition of KCl to fracturing fluids was first described by Black and Hower (1965)[9] with concentrations of 0.8% to 3% being recommended. A German patent was also issued to Hower covering the use of potassium, ammonium, cesium, and rubidium salts as fracturing fluid additives. This patent recommended the addition of KCl to fracturing fluids and suggested a minimum of 0.7%. A minimum of 0.35% was recommended for ammonium chloride.

A list of common salts is given in

Table 6 and a critical salt concentration (CSC) described by Khilar and Fogler (1984).[10]

Table 6—List of Common Salts and CSC

Salt	*Common Name*	*Normal wt%*	*Minimum %CSC*
KCl	Potassium chloride	2%	0.33%
NH4Cl	Ammonium chloride	1 to 2%	0.07%
CaCl2	Calcium chloride	1%	0.3%
NaCl	Sodium chloride	10%	0.41%
LiCl	Lithium chloride	1%	0.3%
CsCl	Cesium chloride	1 to 2%	0.1%

Over the years, it became common practice to add 1-2% KCl to fracturing fluids. It was thought at the time this was an excess amount that gave a suitable margin of safety. However, later studies discussed in this paper provides reasons to use up to 7% KCl. The reason is that as 2% KCl flows past clay material an ion exchange occurs, and 2% KCl will transform to 1.5% sodium salt water, which is too weak to prevent clay swelling.[11]

A 1.0 molar solution (e.g., 7% KCl or 6% NaCl) in the completion fluid should provide adequate economic protection against freshwater swelling of clays based on work done by Gdanski and Schuchart (1997)[12] (**Fig. 11**). NaCl tends to be more economical than KCl and is usually readily available. Understanding this could be more clay control than necessary, the concentration can always be tapered down to a minimum of 2% once a baseline case is established showing this is adequate.

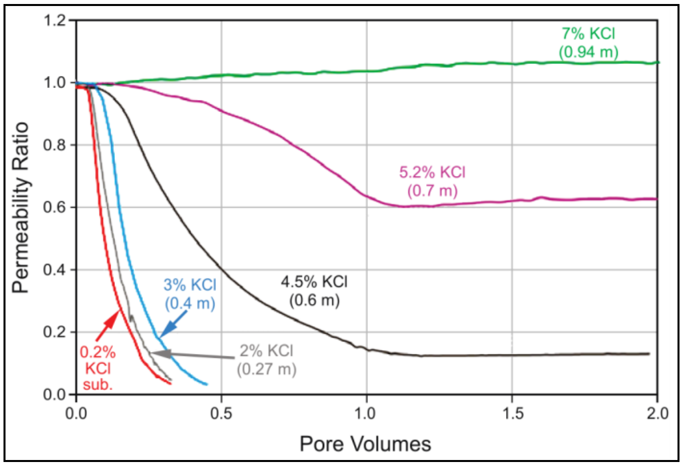

Fig. 11—7% KCl (or approximately 1.0-molar salt solution) is required to properly protect water sensitive clay from swelling.

For this reason, the 7% KCl rule is suggested in a swelling clay environment; 7% KCl will undergo ion exchange, and the result is 6% NaCl. This is enough salt to keep the clay from swelling.

Coating of Clay Particles (COP)

Polymeric inorganic cations consist of a complex structure of multiple cationic sites that are resistant to cation exchange by Na+ and therefore, are more permanent. Disadvantages to such treatments are the necessity to retreat after acidizing, and the restriction to use non-carbonate-containing sandstone formations.

Zirconium oxychloride forms a complex inorganic polymer containing hydroxyl bridging groups. The highly charged nature of these polymers causes them to adsorb onto the clay surface in an irreversible fashion and may bond the clay particles to the sand grain surfaces.

Hydroxy-aluminum is strongly adsorbed by clay. Subsequent polymerization of this ion develops an inorganic coating on clay surfaces, which minimizes clay migration. However, a treated formation should not be acidized because the polymer will be removed from the clay. Also, the requirement of particle overflushes and lengthy curing times have limited its use.[1]

Organic Polymers, Cationic Organic Polymers

Polycationic polymers are organic polymers that are effectively adsorbed by clay, tying them down. These polymers are resistant to acids and are unaffected by carbonate content. Molecular weights range from 5,000 to more than 1,000,000. They need to be applied with care because overtreatment can plug the pore spaces. These polymers are not recommended for permeability less than 30 md.

Modified polyamines are a low-molecular weight, cationic, organic molecule referred to as an oligomer. They perform two functions: enhance the clay-swelling control obtained with KCl and prevent the migration of fines. These products lack the duration of protection that the polymeric clay stabilizers possess, but they do not plug pore spaces the way high-molecular weight polymeric clay stabilizers do. The average length of the oligomer is only 0.017 μm as compared to the 1.1 μm of the polymeric polymers.[13]

Ultralow-Molecular-Weight Cationic Polymer, Poly-Ionic Material.

Hybrid clay-control agents are an ultralow-molecular-weight cationic organic polymer recently introduced for field trials as a temporary clay stabilizer for use in fracture stimulation of extremely low-permeability formations typical of shale formations. Laboratory studies presented herein demonstrate that ultralow-molecular-weight cationic organic polymer is not only a highly efficient temporary clay stabilizer but also provides permanent-type clay treatment, rendering water-sensitive clays insensitive to changes in water composition.

Quaternary amine surfactants impart oil wetness to the clay. Water cannot swell clay if it cannot wet it. However, an oil-wet condition may cause the produced oil to associate with the hydrocarbon “tail” of the surfactant, causing the clay to swell with oil instead of water.[14]

Mineral Fines Stabilizers (MFS)

Various authors have demonstrated the importance of COPs in maintaining fluid conductivity.[15,16,17] MFS addresses the problem of “migrating” clays, silica, and other mineral fines caused by the movement of produced and treating fluids to the wellbore. The MFS must be able to:

- Adsorb on a variety of mineral fines
- Form a long-lasting film
- Reduce the tendency of the particle to flow in produced fluids
- Maintain permeability
- Water wet the formation
- Inhibit water swelling of clays
- Be compatible with most stimulation fluids

The relative molecular weight of 24, with the range being 1 to 50, proved to be most effective in silica fines stabilization. This would put the length in the range of 0.55 μm and the actual weight in the range of 500,000.

Note the normal loading of these polymers in field applications has been 5 to 10 gal/1,000 gal in the pre-pad.

Clays in Oklahoma Formations

There are few “clean” clay-free formations in Oklahoma. While smectite (most damaging when exposed to water) content is usually not present, mixed-layer clays can be abundant. The major portion of clay content in Oklahoma formations are the migrating variety: illite and chlorite.

Fig. 12-15 are a composite summary of clay type and percent by weight for various formations in Oklahoma. Note the major clay component is illite and mixed-layer clay.

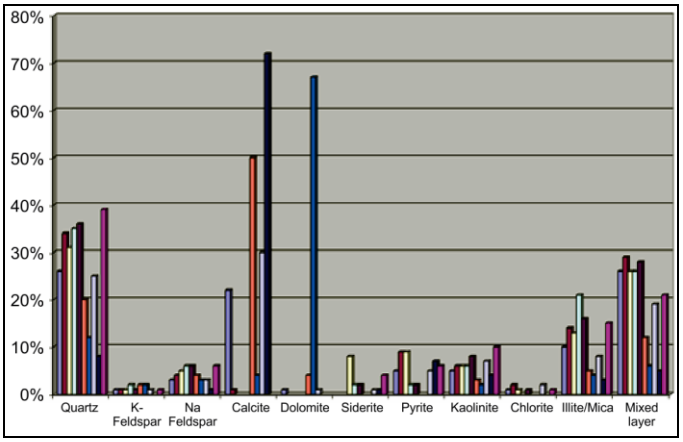

Fig. 12—Caney Shale outcrop analysis of mineralogy and clay type. Each color represents a well in the study.

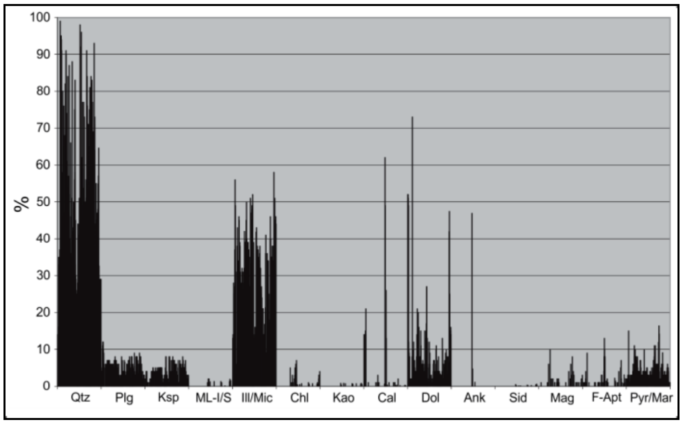

Fig. 13—Woodford major clay type is illite mica. Each color represents a well in the study.

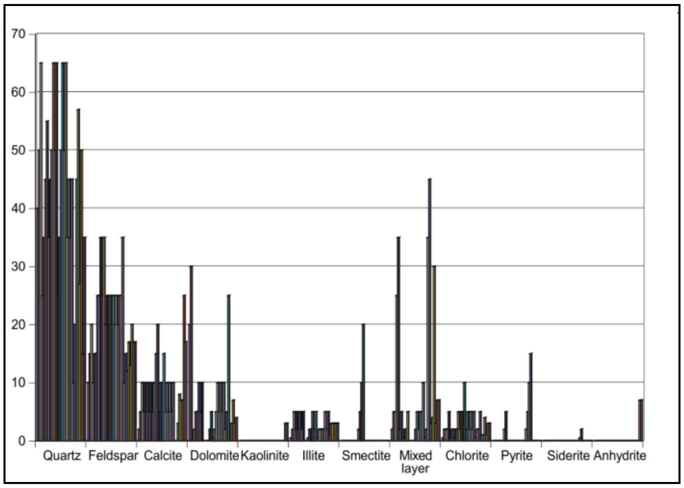

Fig. 14—Granite Wash has a mixture of all clay types; some swelling clay smectite and mixed layer as high as 30 wt%. Each color represents a well in the study.

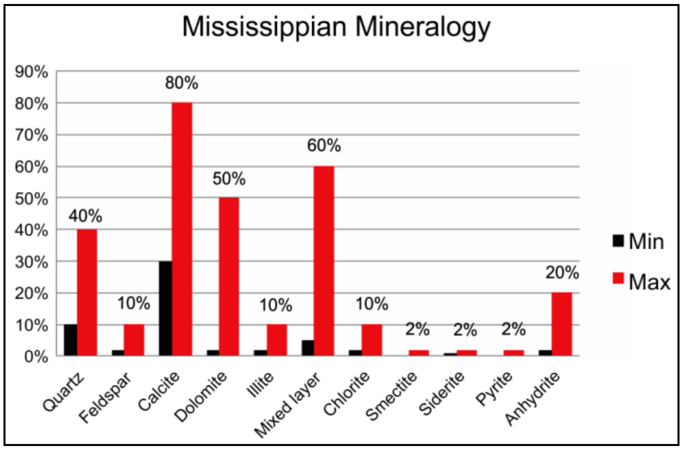

Fig. 15—Minimum and maximum amounts of minerals and clay for the Mississippian formation. Mixed-layer clay can be as high as 60 wt%.

Clay content can vary dramatically in a single zone. **Fig. 16** shows an example from the Sycamore Formation in Garvin County, Oklahoma. Total clay content can vary from 17% to 50% in just 5 ft of depth. The only generalization that can be made in this data set is the clay content decreases with depth.

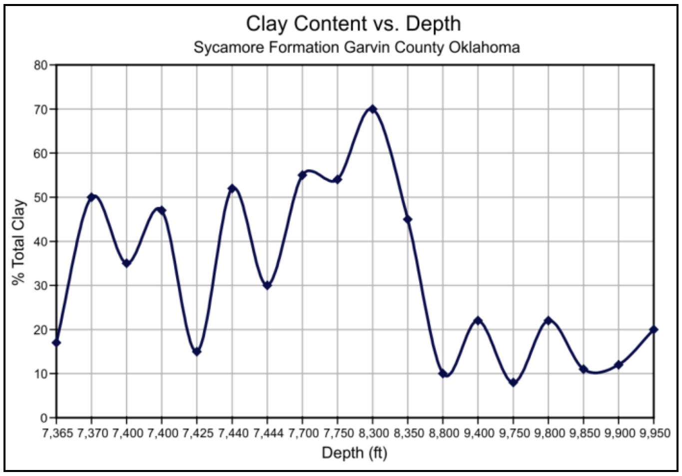

Fig. 16—Clay control vs. depth for the Sycamore Formation in Garvin County, Oklahoma.

Clay damage mechanism can even change within the same formations as shown in **Fig. 17.** Using the Springer shale as an example, some areas have a higher swelling tendency versus other area where there is a higher fines generation tendency.

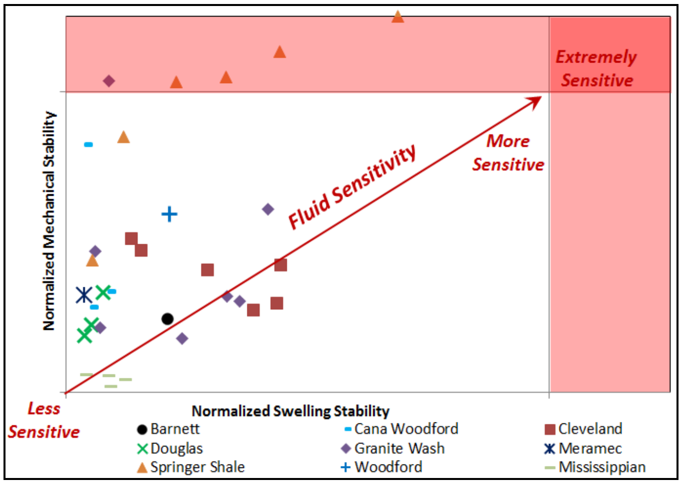

Fig. 17—Mechanical stability and swelling stability metrics for several formations in the Anadarko Basin.

Conclusions

- Significant amounts of swelling and migrating clay exist in most Oklahoma formations.
- A small amount of swelling or migrating clay can potentially cause damage near the wellbore to formation path.
- Determination of clay damage potential by conventional coreflood tests is not possible for tight formations and shale.
- New test methods help determine potential clay damage type and screen clay-control products for use in low-permeability reservoirs.
- These new tests can be performed using drill cuttings inexpensively.

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