FORMATION DAMAGE IN THE PERMIAN BASIN

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ABSTRACT

The Permian Basin began production in the 1920's. With that production of hydrocarbons has come the production of a lot of water. In 2002 it was estimated that the production of water was 400 million gallons per day and that volume has increased steadily. In addition, to water production, many reservoirs have reached an age where the paraffin and asphaltene content of the produced crude has increased. Also, corrosive fluids production has increased, yielding deposits in tubulars. Results of these three situations have made formation damage a significant problem in the Permian Basin and thus causing lower production rates in many wells.

This paper addresses the formation damages created by the events described above as well as those resulting from drilling, cementing and other well operations. In addition, methods of dealing with the removal of these damage are presented.

INTRODUCTION

Formation Damage or Skin Damage is anything that reduces the productivity or injectivity of a well because of solids movement and/or chemical reactions in the formation near the wellbore.[1] This damage can be the result of drilling, completion, production, or stimulation treatments.

Since July 1920 hydrocarbons have been being produced in the Permian Basin. Since then, over 30 billion barrels of oil have been produced from the region and with that a great deal of water. In 2019 produced water in the region was between 9 and 15 million barrels per day according to the Produced Water Society Permian Basin 2019 with forecasts of 75% to 90% increases over the next 10 years. This water production increases the likelihood of Formation Damage. Given how many years the reservoirs in the Permian Basin have been producing the crudes have seen a change in composition to where a higher percentage is made up of heavier hydrocarbons (Asphaltene and Paraffin). Formation Damage causes a great deal of lost revenue for operators in the Permian Basin.

ANALYSIS OF FORMATION DAMAGE

The effect of damage on production rates can be visualized in Figure 1, where a zone of damage near the wellbore is limiting fluid flow. Using Darcy's equation, Figure 2, the effects of the damage can be calculated.[2] Figure 3 illustrates the effect of damage on productivity as a function of the ratio of the damage to undamaged permeability and the depth of damage into the reservoir.

$$S = \frac{(k_e - k_s)}{k_s} ln\left({}^{r_s}/_{r_w}\right)$$

Skin, S, when positive indicates damage and negative stimulation.[3] The equation above indicates that the degree of damage is more significant than the depth of the damage. Total Skin includes formation damage, partial completion, ineffective perforations, two-phase flow, non-Darcy flow and horizontal or deviated wellbore.

If a well's performance is not at a level expected, then an investigation should get underway to determine the root causes of this low performance. Figure 4 is a simplistic flow chart of the methodology to this investigation. The first thing to do in the investigation if possible, would be to perform a pressure build-up or draw down and create a Horner Plot (Figure 5) to evaluate a total skin for the well.[4] The next step would be to look at the well's productive system. Figure 6 is an illustration of the components of a well system. Software exists for the analysis of these components to help identify where pressure problems exist thus helping to quantify how much of a well's poor performance is due to Formation Damage. The next step would be to look at the well history, producing interval mineralogy and the characteristics of the produced fluids trying to identify what formation damage might be possible.

FORMATION DAMAGE BASED ON WELL TYPE

Along with the understanding of the well's mineralogy the type of well helps to identify possible damage mechanisms and therefore helps to determine possible treatments to negate the effects on production or injection. Table 1 lists a summary of damage mechanisms that could be responsible for low productivity based on whether the well is new, old or an injection well.

New Well

Knowing at what stage in a well's life cycle can greatly help in limiting the choices of what damage has occurred. Therefore, if you are investigating problems with a newly drilled well, you pay special attention to all the operations associated with the creation of the well and realize that horizontal wells are more susceptible to formation damage than vertical wells. First look at the drilling history and particularly the drilling fluid used, its characteristics, composition, and losses. Questions to ask regarding the drilling fluid are whether it is oil based or water based, what was used for viscosity, what materials were used to achieve the density of the fluid (weighting agents), what was the fluid loss control, whether lost circulation materials were used and how these fluid components could have interacted with the mineralogy[56] An important point to remember is that if the drilling fluid used Partially Hydrolyzed Polyacrylamide (PHPA) for viscosity control never acidize always use a strong oxidizing solution to clean up this polymer.

Next look at the cementing operations for composition and losses again regarding the mineralogy. Lastly look at the completion fluids, perforating operations and stimulation if any performed.[7] All these operations have the potential to result in solids invasion of a reservoir, chemical reactions with the mineralogy of the reservoir or the reservoir fluids. Once damage potentials have been identified then approximate the depth of penetration of these mechanisms. Solids are limited to a few inches if possible unless whole drilling fluid or Cement has been lost in the reservoir then the depth is much greater. If the damage is primarily from the leaked off fluids from the drilling or cementing operations, then the damage can be several inches to feet into the reservoir depending on the permeability. Perforating damage would be limited to a few inches out from the perforation tunnel. Stimulation damage can be severe and have a great deal of depth into the reservoir. This is typically the result of not paying close enough attention to the materials being pumped and their interaction with the reservoir mineralogy and fluids.

Old Well

Old producers can have several problems occur, including emulsions, corrosion, scale deposits, migratory fines, damages from stimulation treatments and deposition of organic materials (paraffin and/or asphaltene).

EMULSIONS

Emulsions can occur with production because of the natural surfactants present in crude oil or they can be created by fluids pumped or lost into the formation. Emulsions can be either water external phase or oil external phase in composition. A produced emulsion should be evaluated as to the external phase and that will dictate the base fluid to be tested with various surfactants to break the emulsion. It is very common for there to be fine particles of silicate stabilizing these emulsions.

Preventing emulsions when performing well operations, such as stimulations, workovers, etc. is a matter of laboratory testing of the fluids to be used with crude from the interval to be treated or subject or potential losses. Prevention testing should include possible fines that might be associated with the crude and would thus stabilize the emulsion.[8,9] Typically the amount of surfactant necessary to prevent an emulsion is low, 0.1 to 0.3%. Breaking an emulsion could take 1.0 to 3.0% surfactant. Depending on whether the emulsion is oil external phase or water external phase will determine the solvent system to be used in the removal. A guideline for the volume to use would be to start with 25 gallons per foot of interval. After clean up has been performed it would be recommended to perform a small acid treatment with surfactants to help insure the water wet characteristics of the formation. Pump rates for the solvent treatment would be 2-3 BPM and for the acid treatment 4-5 BPM.

INORGANIC DEPOSITION

Inorganic deposition refers to deposits of scales such as Calcium Carbonate ($CaCO_3$), Gypsum (Calcium Sulfate, $CaSO_4 \cdot 2H_2O$), Barium Sulfate ($BaSO_4$), Sodium Chloride (NaCl) and less commonly Strontium Sulfate ($SrSO_4$), and corrosion products such as Iron Sulfide (FeS), Iron Carbonate ($FeCO_3$), and Iron Oxides (Fe2O3, Fe_3O_4). The scales can be formed in the formation matrix and fractures, perforations, the wellbore, downhole pumps, tubing, and surface facilities. Corrosion of the tubulars by Carbon Dioxide (CO_2) in the form of Carbonic Acid (H_2CO_3), Oxygen (O_2) or Hydrogen Sulfide (H_2S).[10,11] A lot of times solid samples may be retrieved from the wellbore and evaluated to determine what is the problem.

Barium Sulfate Scale

The barium sulfate scale is the result of mixing waters. Its solubility in water and acid makes its removal difficult. Scaling increases with decreasing temperature. Normally a mechanical method is used to clean out a well. To remove from perforations and the near wellbore region there are some chemicals available which will dissolve small amounts of the scale, however these have limited success in the near wellbore region and typically a well will be reperforated.

Calcium Carbonate Scale

Carbonate scales are the most abundant. Figure 7 shows examples of Calcium Carbonate Scale with some organic material present in the sample to the right. Calcium Carbonate scale is formed by first the CO_2 dissolved in the formation water forming carbonic acid which then dissociates to carbonate and bicarbonate which lowers the pH. In most cases the carbonate ion interacts with the calcium ions and precipitates.[10] Additional precipitation of calcium carbonate depends on the equilibrium: [11]

$$Ca^{2+} + 2HCO_3 \rightleftarrows CaCO_3 + H_2O\left(K_{sp} = 10^{-8}\, {}^{mole}/_{liter}\ at\ 20^{\circ}C\right)$$

Due to the widespread distribution of dissolved calcium bicarbonate contained in formation brine solutions favor the formation of calcium scales when appreciable amounts of calcium ions become available. Temperature and pressure are important physical factors affecting the formation of the scale. Thus, as the pressure decreases the CO_2 comes out of solution thus shifting the above equilibrium to the right and therefore precipitation of more calcium carbonate. The lower the temperature the more soluble the calcium carbonate. Thus, calcium carbonate scale formation in wells is less as the fluids move up hole to a lower temperature. However, there is an increase where there is a lot of turbulence and/or a lot of contact time. Evaluation using one of the many scale predicting models available of a water analysis can determine the presence of a tendency to form calcium carbonate scale.

Treating for calcium carbonate scale involves pumping hydrochloric acid, typically at 15%. The volume used will depend on the apparent depth at which the scale first started to come out of solution in the formation. The depth will be based on an educated guess. Additives in the acid would include corrosion inhibitor, a non-emulsifier if an oil well, a surfactant to aid in leaving the formation water wet if a gas well, a suspending agent to keep any undissolved solids moving out of the well and iron control additives. At a minimum the iron control should be a chelating agent at a concentration based on the pumping company’s laboratory data to control iron. The preferred additive would be a good reducing agent to keep the iron III in the iron II state thus avoiding precipitation of iron hydroxide. The treatment should be pumped at a rate below fracturing (generally at 2-3 BPM to allow plenty of contact time for the scale removal . The treatment should be recovered as soon as possible.

Calcium carbonate scaling can be controlled using threshold inhibitors that influence crystal nucleation and/or growth.[10]

Calcium Sulfate Scale

Three different calcium sulfates occur, each with a different water of hydration, Anhydrite ($CaSO_4$), Hemihydrate ($CaSO_4 \cdot 1/2H_2O$) and Gypsum ($CaSO_4 \cdot 2H_2O$).[10] Calcium Sulfate scale formation is due either to the mixing of waters or a drop in pressure. Figure 8 shows an example of calcium sulfate scale formation in tubing. Scaling increases with increased temperature, evaporation of the water, increased turbulence, and magnesium concentration. Figure 9 illustrates the solubility of Gypsum and Anhydrite as a function of temperature. As with calcium carbonate the scale predicting models can determine whether calcium sulfate scaling is possible or probable.

There are two options for removing calcium sulfate scale. First option is to pump a converter that changes the calcium sulfate scale into an acid soluble material. This converter should be allowed to soak on the scale for at least 16 hours and then circulate it out of the well. Next acidize with hydrochloric acid, typically 15%. The second option is to pump a strong chelating solution to dissolve the calcium sulfate scale. As with the converter it will be necessary to leave the solution in contact with the scale for approximately 16 hours depending on the thickness of the scale.

Calcium sulfate like calcium carbonate scaling can be controlled using threshold inhibitors that influence crystal nucleation and/or growth.[10]

Deposition of Iron Materials

One source of scaling is from corrosion of the tubulars in the well. These deposits can be iron oxides or rust (Fe_2O_3, Fe_3O_4), iron carbonate ($FeCO_3$), and/or iron sulfide (FeS). Iron oxides are corrosion products of iron-based metals reacting with oxygen in aqueous fluids or very hot gases that contain oxygen. All iron-based tubulars have some degree of iron oxide present on their surfaces. Iron carbonate is the result of the chemical reaction of carbon dioxide in aqueous fluids on iron-based metals. Iron sulfide is the product of the reaction of hydrogen sulfide on iron-based metal. All these materials are in the wellbore and can be cleaned out with acid. The problem that can arise is that if any of the acid enters the formation after dissolving these materials there is a potential damage to the formation from reprecipitation out of the acid as it spends. Reducing the iron content of the fluid entering the formation during an acid treatment can be accomplished by performing a pickling job. A volume of acid (generally 100 gallons 15% HCl per thousand feet of tubing or casing) is pumped down the tubing or casing and then reversed out. This reduction means that the iron control in the treatment acid to be pumped into the formation can be more effective in preventing iron hydroxide precipitation as the acid spends. In dealing with iron sulfide, it is a little more difficult to prevent the reprecipitation in the formation. In this case a strong chelating agent is necessary to keep the dissolved iron in solution and a material to control the sulfide ion is also essential to reduce the reprecipitation of the iron sulfide.

Iron control materials can be single additives or a combination of materials to better accomplish control. Additives to tie up the iron and keep it in solution are citric acid, NTA and EDTA. Since iron III is the more difficult material reducing agents are used to make iron II these vary in composition and are proprietary materials offered by pumping service companies. In addition, acetic acid can be added to provide a buffering effect to help stabilize reaction products regarding pH of the spent acid. In very mature oil producing reservoirs a combination of all three types plus an asphaltene stabilizer has been found to be very beneficial both in controlling iron reprecipitation but also in controlling asphaltene sludge formation.

Sodium Chloride

Typically, Halite (NaCl) formation is observed in high-pressure, high-temperature (HP/HT) gas wells.[10] This type of scale formation is because of evaporation caused by a pressure drop. This is an ongoing problem and requires continuous intervention. The salt can be removed by pumping fresh water. Gas wells producing high concentrations of carbon dioxide are more serious since CO_2 holds evaporated water better than methane.

ORGANIC DEPOSITION

Paraffin and asphaltene are the common organic scales or deposits that are found in oil wells. Paraffin and asphaltene differ significantly in their chemical structure and should be considered as separate organic materials. Paraffins are straight chain or branched chain hydrocarbons called alkanes and have relatively high molecular weights. Each paraffin has a specific melting point and specific solubilities in various solvents.

Asphaltenes are polycyclic aromatic, complex compounds of high molecular weight (weights higher than paraffins).   Figure 10 is an example of the chemical structure of an asphaltene. Unlike paraffins they have no specific melting point. These materials are not soluble in the crude but are stabilized by resins and maltenes. They are polar in nature due to the presence of oxygen, sulfur, nitrogen, and various metals in their structure. This means that they can be attracted to the formation and alter the wettability. In addition, the structures also have straight chains which can attract paraffin molecules thus having layers of paraffin building up on the asphaltene that has attached to the formation or metal surfaces. With a reservoir ageing the light ends are produced first and this destabilizes the asphaltene structures due to the stripping away of the maltenes and resins. The drop in reservoir pressure near the wellbore also destabilizes the asphaltene structures causing them to aggregate. They are also sensitive to shearing and the presence of positive ions such as acid (H^+), iron II (Fe^{+2}), and iron III (Fe^{+3}). Because of the effects of acid and iron ions, special precautions regarding the additives used in an acid treatment on a well with asphaltenes must be implemented. Wells drilled with oil-based drilling fluids may be subject to asphaltene destabilization, especially if the oil is diesel.

Treatments for paraffin and/or asphaltene deposition primarily involve pumping solvents and typically these are either xylene or terpenes. In some cases, a preflush of solvent is used followed by an acid system with a solvent dispersed within it. Generally, the volumes used vary depending on the assumed extent of the damage. When designing an acid treatment compatibility testing of the treating fluid and formation fluids should be performed. In addition to that test a test for asphaltene sludge should be added. Figure 11 shows what can show up when performing this additional test. The simplest test just adds 30 minutes at reservoir temperature to the compatibility test and requires pouring the fluids through a 100-mesh screen. A more complex test is to add some iron III to the acid when doing the compatibility test.

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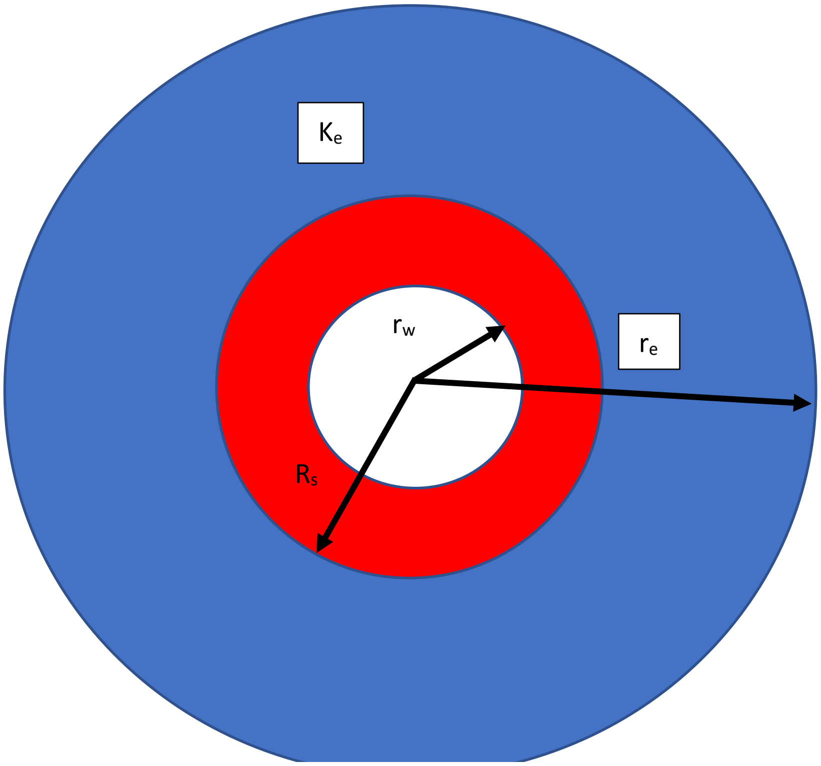


Figure 1- Damage Area Around Wellbore

$$Q = \frac{7.082kh(P_e - P_w)}{\beta_0 \mu ln\left({}^{r_e}/_{r_w}\right)}$$

$$K_{avg} = \frac{k_s k_e ln\left({}^{r_e}/_{r_w}\right)}{k_s ln\left({}^{r_e}/_{r_s}\right) + k_e ln\left({}^{r_s}/_{r_w}\right)}$$

Where:

K_{avg}= Average permeability through reservoir and near wellbore damage

K_s= Permeability in near wellbore damaged area

K_e= Permeability in undamaged reservoir

Figure 2- Darcy's Equation of Radial Flow

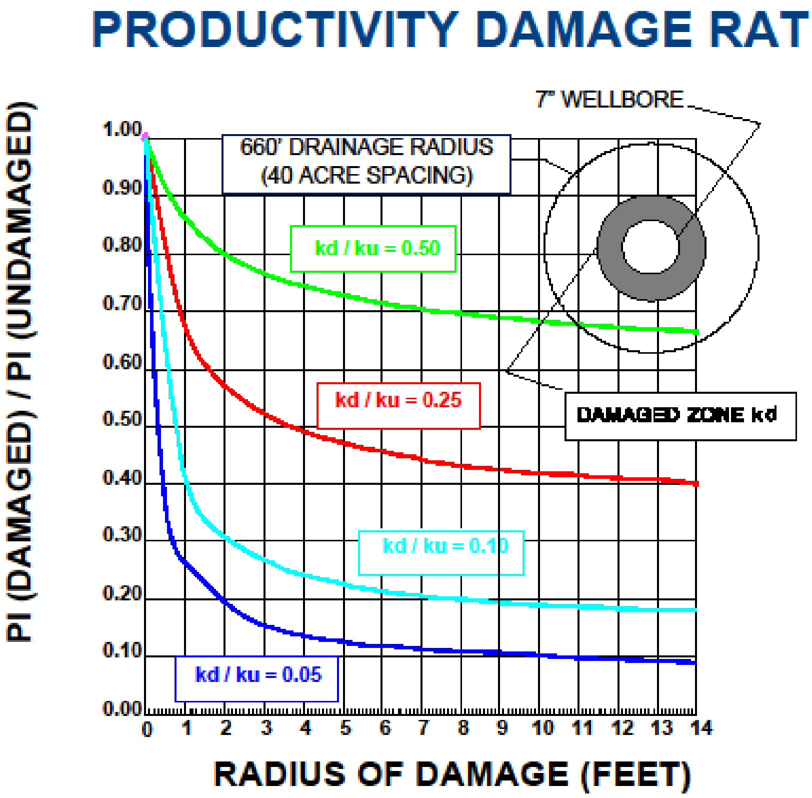


Figure 3 - Productivity Ratio

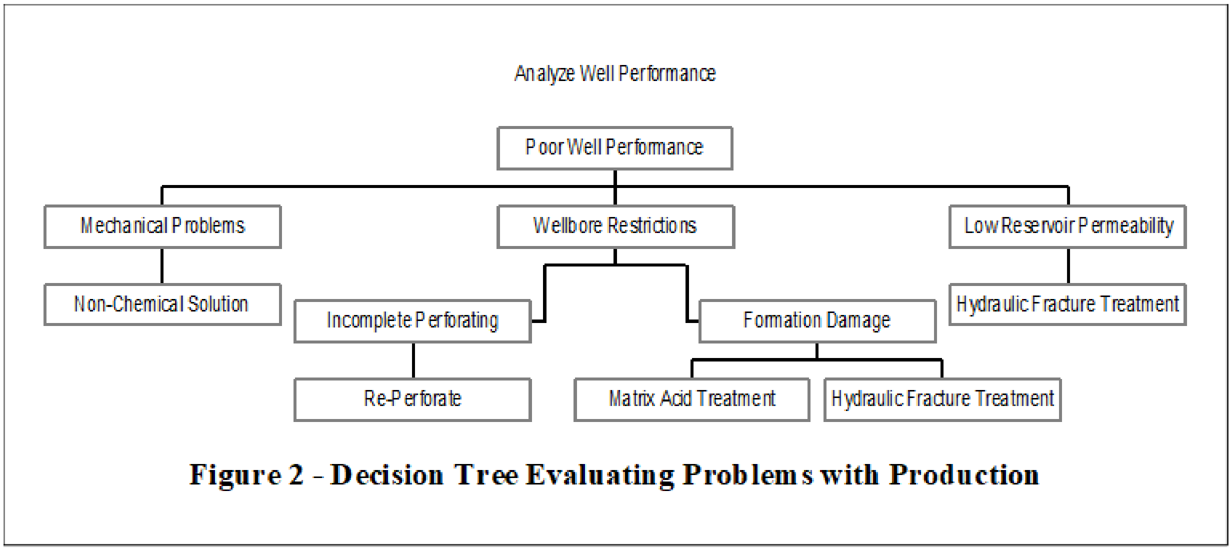
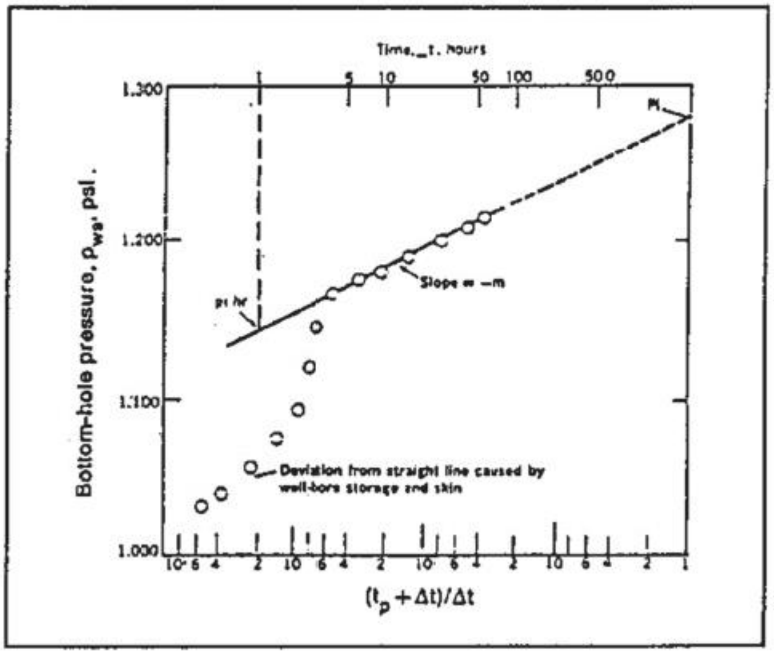


Figure 2 - Decision Tree Evaluating Problems with Production

Figure 4 - Analysis Flowchart



$$k = \frac{162.6\ qB\mu}{mh}$$

$$s = 1.151\left[\frac{p_{1\,hr} - p_{wf}(\Delta t = 0)}{m} - \log\left(\frac{k}{\phi\mu c_f\, r_w{}^2}\right) + 3.23\right]$$

Figure 5 - Horner Plot and Equation for Skin

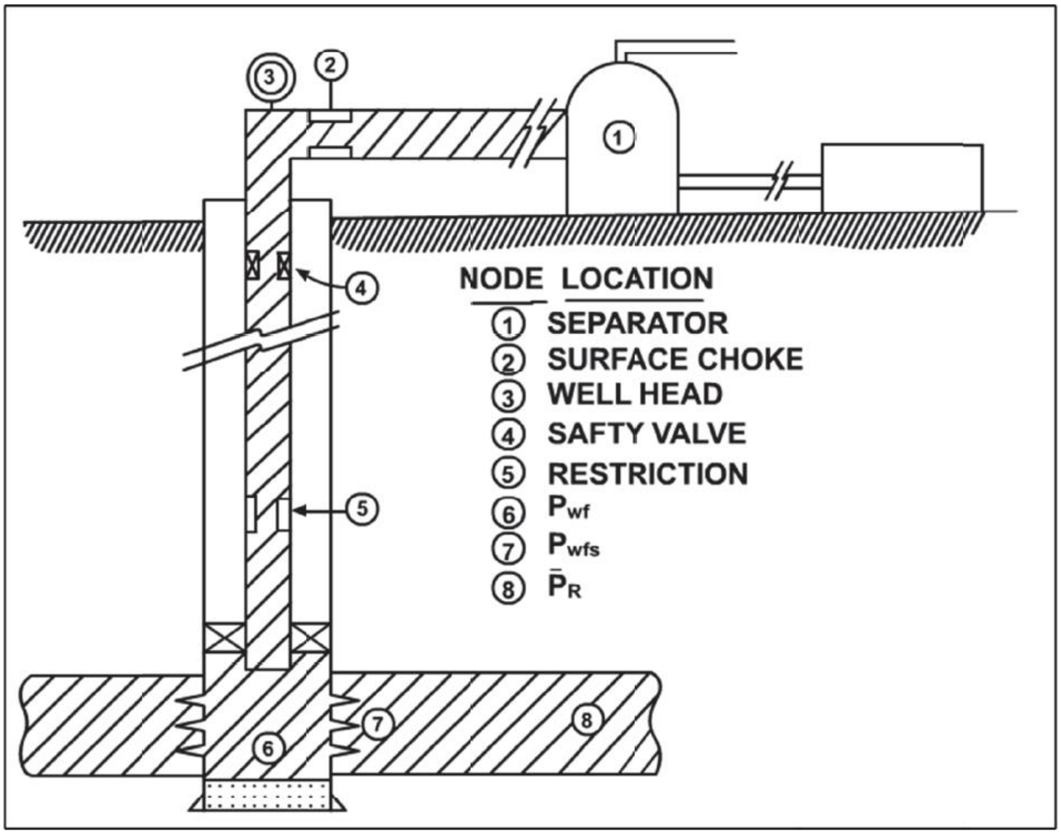


Figure 6 - Example of Components of Well Productive System

Table 1 – Formation Damage Based on Well Type		
New Well	**Old Well**	**Injection Well**
Plugging Solids	Emulsions	Emulsions
Emulsions	Scale	Scale
Water Block	Organic Deposits (Paraffin and/or Asphaltene)	Organic Deposits (Paraffin and/or Asphaltene)
Wettability Alteration	Polymer Residue	Polymer Residue
Fines Migration	Corrosion	Corrosion
Bacterial Slime	Fines Migration	Fines Migration
Polymer Residue		Bacterial Slime
Perforation Tunnel Compaction		
Filtrate Effects on Mineralogy		
Polymer Residue		

Figure 7 - Examples of Calcium Carbonate Scale and Organic Deposition

Figure 8 - Example of Gypsum Scale

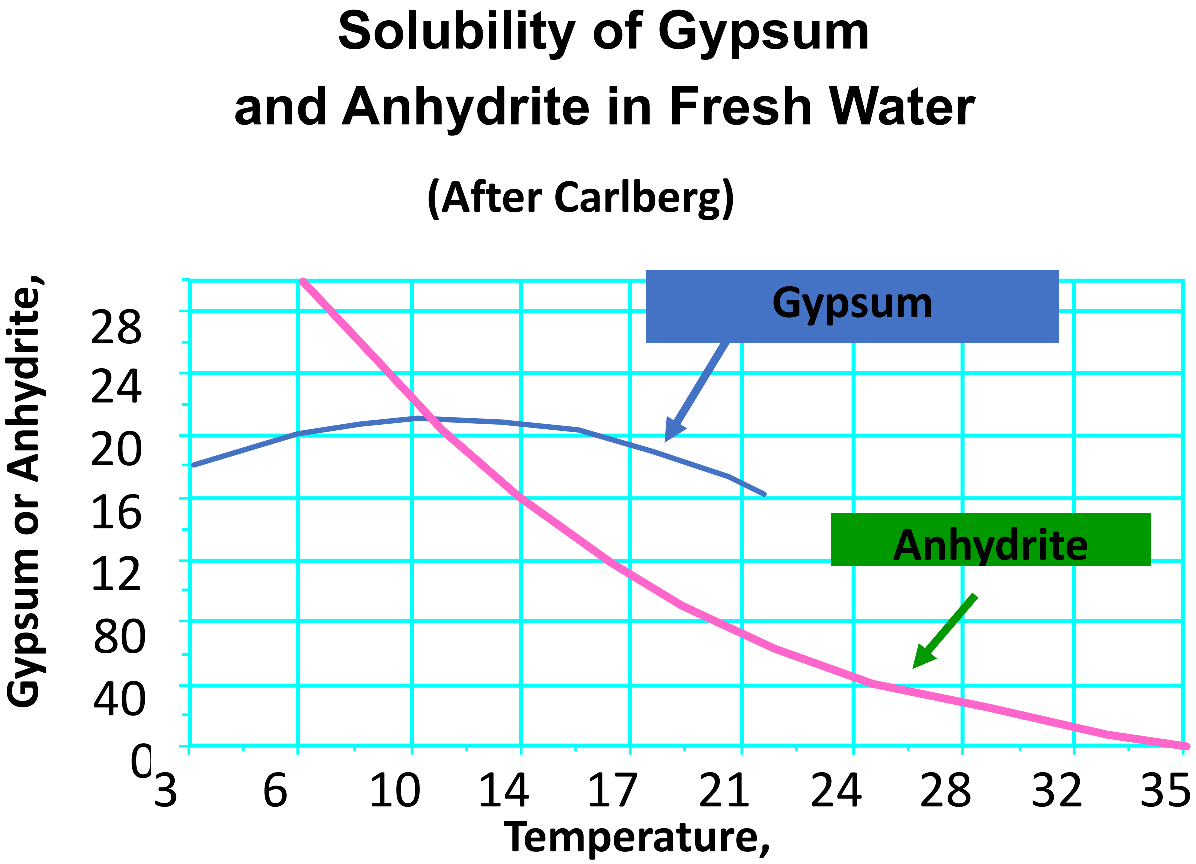


Figure 9 – Solubility of Calcium Sulfate

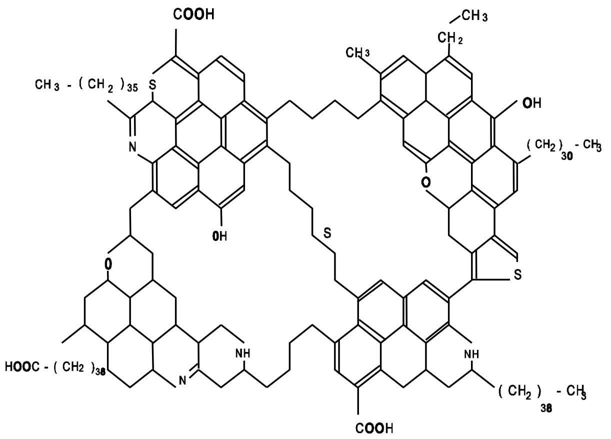


Figure 10 – One Example of an Asphaltene Chemical Structure

Figure 11- Example of Asphaltene Sludge