

Petroleum Extension - The University of Texas at Austin

TREATING OILFIELD EMULSIONS FOURTH EDITION



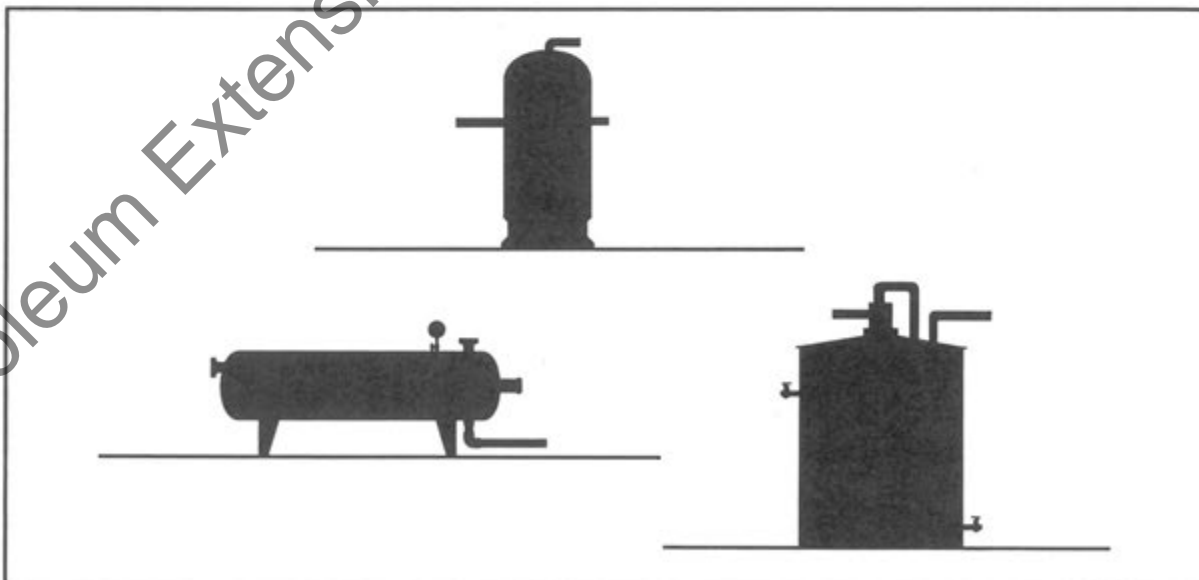
Treating Oilfield Emulsions

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After completing Segment I, you should be able to —

1. Recognize the characteristics that make a well produce an emulsion.
2. Recall the conditions that may result in emulsion production.
3. State pipeline specifications for oil and identify the reasons for these specifications.
4. Recall refinery requirements for oil.
5. Identify the duties of the production foreman and the pumper (lease operator).
6. Recall the factors that should be considered in determining the type of treating.
7. Recall the consequences of using excessive heat in emulsion treating.
8. Identify emulsion components and types.
9. Identify the effect that chemicals, heat, and electricity have on an emulsion and recall when they are used in emulsion treating.
10. Recall the conditions that create a stable emulsion and recall how to prevent the formation of such an emulsion.
11. List the causes of agitation.
12. Recognize the flow line characteristics that may cause stable emulsions to form.
13. Recall ways of minimizing stable emulsions in pumping wells.
14. List the various treating methods and recall their effects on an emulsion.
15. Recall the factors that influence treating.
16. Recognize the equipment used in emulsion treating and recall how the various components operate.
17. List the main parts of an indirect heater.
18. Recall the proper procedure for firing up a heater.
19. Recall how an indirect heater operates.



The Treating Problem

At some time in the life of almost every oilwell, more water is produced with the crude oil than is acceptable to the pipeline company or other carriers. Some wells may produce water from the beginning, but, more often, water encroachment comes later in the life of the field. Figure 1 shows, in simplified form, one source of water produced with oil. Both oil and water are contained in the pores of the rock that makes up the reservoir. In figure 1, a large quantity of water lies under the oil. Early in the life of the field, some of the wells that are drilled near the point of oil-water contact (A) produce excessive amounts of water. Other wells, which are drilled higher on

the reservoir (B, C), may produce clean oil at the beginning. Figure 2 shows the same reservoir later in the life of the field. Note the relationship at this later date between the position of each well and what each is producing.

Figure 3 illustrates another possible cause of water in oilwells. Casing failure coupled with a poor cementing job at a point above the producing zone allows water to enter the well and contaminate production. To correct the problem, the casing can be patched and a squeeze cementing job can be performed, or a packer can be placed in the tubing-casing annulus to form a temporary seal above the oil zone and exclude the water.

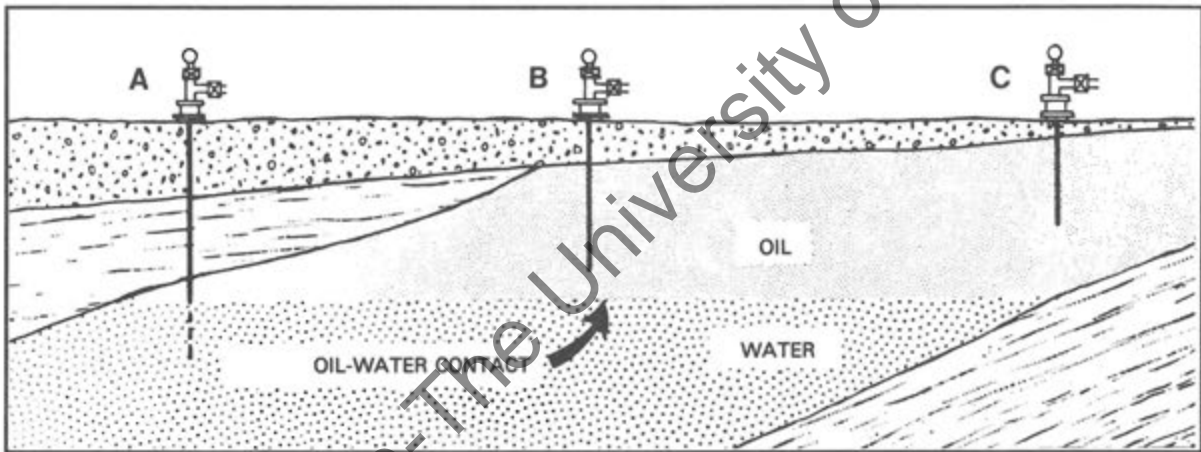


Figure 1. Sketch showing relative position of oil and water in early life of reservoir. Well A requires plugging back. Wells B and C produce clean oil.

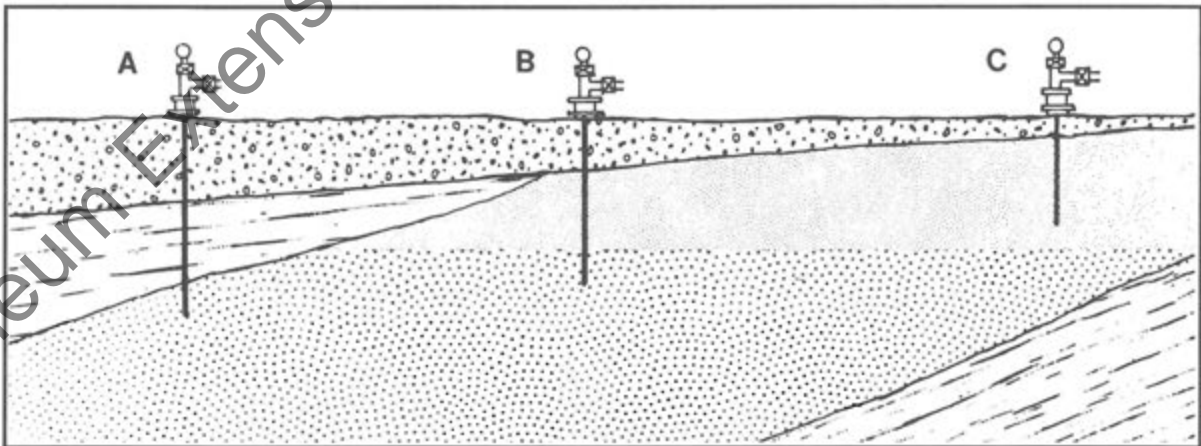


Figure 2. Same reservoir as in figure 1, portraying later conditions in life of field. Well A is completely watered out. Well B produces water and cut oil. Well C continues to produce clean oil.

An *emulsion* is a combination of two liquids that do not mix under normal conditions. Such liquids are said to be *immiscible*, or incapable of mixing. In an emulsion, one of the liquids is spread out, or dispersed, throughout the other in the form of droplets. These droplets can be of all sizes, from fairly large to very small. Sometimes droplets are so small that more than fifty of them could be placed on the head of a pin. A *stable emulsion* is an emulsion that will not break down without some form of treating. Three conditions are necessary for the formation of a stable emulsion: (1) the liquids must be immiscible; (2) sufficient agitation must occur to disperse one liquid as droplets in the other; and (3) an emulsifying agent, or emulsifier, must be present.

Many emulsions, such as in insecticides and medicines, are prepared for commercial use. They are made up of two or more liquids that do not normally mix, plus the emulsifying agent. A common household emulsion is mayonnaise. Basically, it is made of vegetable oil and vinegar with eggs used as the emulsifying agent. This combination would not remain mixed if the eggs, or some other emulsifying agent, were not present. The oil and vinegar could be mixed by violent agitation, but they would soon separate after agitation was stopped. Similarly, to form a stable emulsion of crude oil and water, an emulsifying agent must be present. Emulsifying agents commonly found in petroleum emulsions include asphaltenes, resinous substances, oil-soluble organic acids, and other finely divided materials that are more soluble, wettable, or dispersible in oil than in water, for example, iron, zinc and aluminum sulfates, calcium carbonate, silica, and iron sulfide. Each of these emulsifiers usually occurs as a film on the surface of the dispersed droplets.

In an emulsion, the liquid that is broken up into droplets is the *discontinuous, dispersed, or internal phase*. The liquid that surrounds the droplets is the *continuous, or external, phase*. An emulsion of oil and water may have either oil or water as the dispersed phase, depending on the characteristics of the emulsifying agent. In most cases,

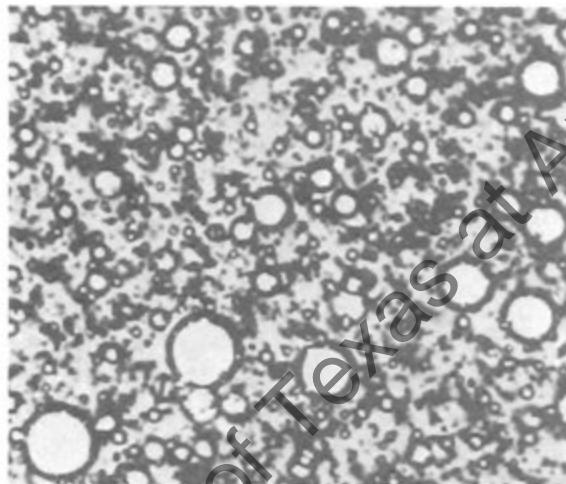


Figure 4. A photomicrograph of a water-in-oil emulsion

however, water is dispersed as droplets in oil (fig. 4). An oil-water emulsion may contain from a trace to 90 percent or more water. An emulsion may also be *tight* (difficult to break) or *loose* (easy to break). Whether an emulsion is tight or loose depends on a number of factors, four of which are (1) the properties of the oil and water; (2) the amount of agitation, or shear, it undergoes; (3) the percentage of oil and water found in the emulsion; and (4) the types and amount of emulsifiers present.

Occasionally, emulsions produced from some fields are *reverse emulsions*, in which oil is the internal phase and is dispersed as droplets in water. Very rarely, oil is produced in a *dual emulsion*, in which the dispersed phase is droplets of oil-in-water emulsion and the external phase is oil. As stated before, however, most oilfield emulsions are normal emulsions in which water is dispersed throughout the oil.

In a water-in-oil (normal) emulsion, two forces are in direct opposition. One force is the film of emulsifying agent that surrounds the water droplets. This force tends to prevent the droplets from merging to form larger drops, even when the droplets collide. The other force is the opposite tendency, that of water droplets to join to form larger drops. Larger drops tend to yield to the

Emulsions and Production Practices

As oil and water are produced from a well, if an emulsifying agent is present and if agitation of this combination of well fluids occurs, an emulsion will form. Once an emulsion forms, it may remain loose and be relatively easy to treat or it may, because of the way in which it is handled in the production system, turn into a stable and difficult-to-treat emulsion. Unfortunately, many other problems occur besides those involving emulsions, and sometimes the action required to solve those problems may not be ideal for preventing the formation of tight emulsions. Instituting new methods or installing new equipment just to minimize the formation of tight, stable emulsions is, however, frequently not economically justifiable. Operators must formulate production techniques by taking into account all factors, not merely those that pertain to emulsion problems.

Each oilwell has its own characteristics and offers individual problems, but previous experience on similar wells often indicates a solution. Trial and error, however, is sometimes the only way to find the cause or to minimize the formation of a difficult emulsion. Some general practices are available, however, that, if followed, can reduce oil-and-water emulsification.

As mentioned before, certain conditions must exist before an emulsion can form: (1) the liquids must be immiscible; (2) sufficient agitation must occur to disperse one liquid as droplets in the other; and (3) an emulsifying agent must be present to stabilize this dispersion. In oil production, all of these conditions frequently occur. In some cases, however, it is possible to minimize, if not prevent, two of the three conditions. Since treating is done to disrupt or counteract the effect of the emulsifying agent, either (1) water and oil must not be produced simultaneously, or (2) any agitation great enough to form a more stable emulsion must be avoided. Water production can sometimes be reduced, if not eliminated, by remedial cementing procedures, such as plugging back the wellbore, so that the production is withdrawn from a point higher in the reservoir. Because it is usually very difficult to exclude water from the wellbore completely, however,

the best method for avoiding a tight, difficult-to-treat emulsion is to minimize agitation.

The amount of water that disperses in oil with a given amount of agitation depends on the relative amounts of the two liquids. If there is not much water, not much agitation is needed to disperse it in the oil. Conversely, if there is a lot of water, a lot of agitation is needed to disperse it in the oil. If there is a lot of water in an emulsion being agitated, the emulsion tends to break down because the large number of water droplets in the emulsion strike each other frequently, coalesce, and fall out. Therefore, less water gets dispersed, and the stability of the emulsion is reduced. It is possible, in some instances, to reduce treating difficulties by adding water to the well fluid ahead of the point of agitation. This procedure is used in relatively few cases, however.

A *free-water knockout*—a vessel that removes free water from the well fluids—may be placed ahead of the point of agitation. This works very well if the well fluid is easily separated into free oil and water; however, this procedure could have a detrimental effect if the presence of excess water makes the emulsion looser.

Minimizing Stable Emulsions in Flowing Wells

Violent agitation of oil and water being produced in flowing wells causes water droplets to disperse in the oil and leads to the formation of very stable emulsions, which are often difficult to treat. Such agitation is caused primarily by gas coming out of solution as pressure is decreased and by turbulence that occurs when production flows through restrictions, fittings, and sharp bends in the tubing and lead lines.

Surface Chokes

When a surface choke or a back-pressure valve is used to control production, most of the emulsion is formed immediately downstream from it. Upstream from the choke or the valve, pressure is relatively high compared to that on the downstream side. (Higher upstream pressure can be confirmed by noting that tubing pressure at the

The Basic Principles of Treating

For purposes of this manual, *treating* refers to any procedure designed to separate foreign matter from crude petroleum. *Foreign matter* may include water, salt, sand, sediment, and other impurities in oil; paraffin wax and asphaltenes are not considered impurities here. Basically, treating involves allowing time for water to settle out of an emulsion and be drained off. Settling time and draining are accomplished in various mechanical devices such as gun barrels (wash tanks) and free-water knockouts. To speed up settling time, one or more of the following procedures may also be used:

1. applying heat;
2. applying chemicals;
3. applying electricity; and
4. adding diluents to reduce viscosity.

Factors Influencing Treating

The factors involved in treating water-in-oil emulsions include breaking the films surrounding the small water droplets, coalescing the droplets to produce larger drops, and allowing the water drops to settle during or after coalescence. In theory, all emulsions separate into oil and water if allowed to settle for an unlimited time. Indeed, a considerable amount of water produced with petroleum does separate without the assistance of heat, chemicals, or other devices. However, the small water particles in water-in-oil emulsions are usually surrounded by a tough film that gives the appearance of plastic wrap when viewed under a microscope (fig. 10). This film resists being broken, and, until it is broken, the water droplets cannot coalesce—at least, not in any reasonable length of time (fig. 11). Therefore, heat, chemicals, electricity, mechanical devices, and various combinations are normally required to cause the film around the water droplets to break and coalesce (fig. 12).

It should be emphasized that no two oilfield emulsions are alike. The procedures used to treat the emulsion produced from one field almost never work on an emulsion from a different field. In fact, the emulsion produced from individual wells within the same field sometimes varies.

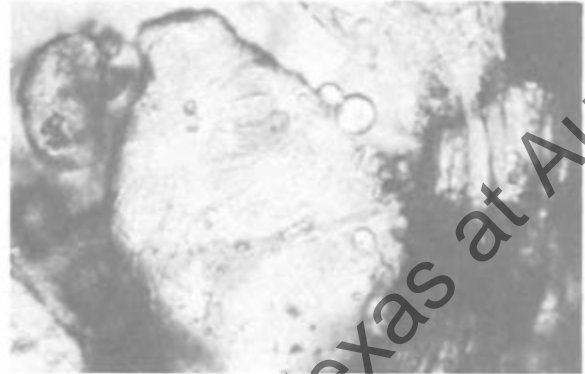


Figure 10. A photomicrograph of a water droplet in a water-in-oil emulsion. Note that the rigid film surrounding the water droplet looks like plastic wrap.



Figure 11. A photomicrograph of a water-in-oil emulsion showing two water droplets touching but unable to merge because of film around the droplets.

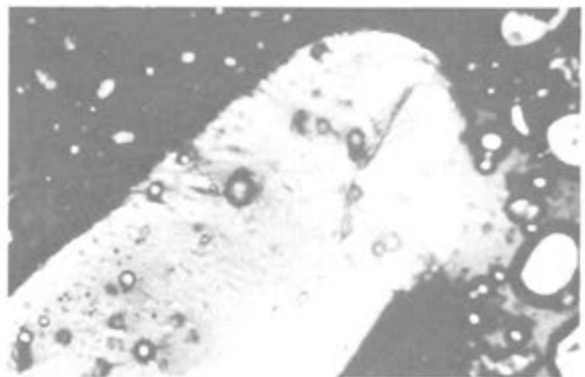


Figure 12. A photomicrograph of a single water droplet in a treated emulsion. Note that the film is breaking.

The Application of Heat in Treating

Heat alone does not cause an emulsion to break down, except in rare instances. Usually, the application of heat is an auxiliary process to speed up separation. Indeed, if at all possible, heat is eliminated entirely from the treating process. Further, in those cases where heat is necessary, the heater is usually an integral part of a single treating vessel in which heating and treating are both accomplished. Because separate heaters are sometimes employed in treating systems on certain leases, and because the operation of separate heaters is applicable to the operation of heaters combined with treating vessels, it is worth studying them.

with a bath of water, corrosion inhibitors, and, in cold climates, diethylene glycol, or antifreeze. The water bath transfers heat from the fire tube to the flow-tube bundle. As cold emulsion passes through the bundle, it is in turn heated to a selected outlet temperature. The heated water bath circulates in the shell by means of a thermosiphon effect, in which the warm water rises and the cool water falls to be reheated by the fire tube. The fire tube and flow-tube bundle are removable for easy cleaning, inspection, and replacement.

Since the flow tube is subject to corrosion both from the emulsion flowing inside it and from the water bath surrounding it, the return bends in the

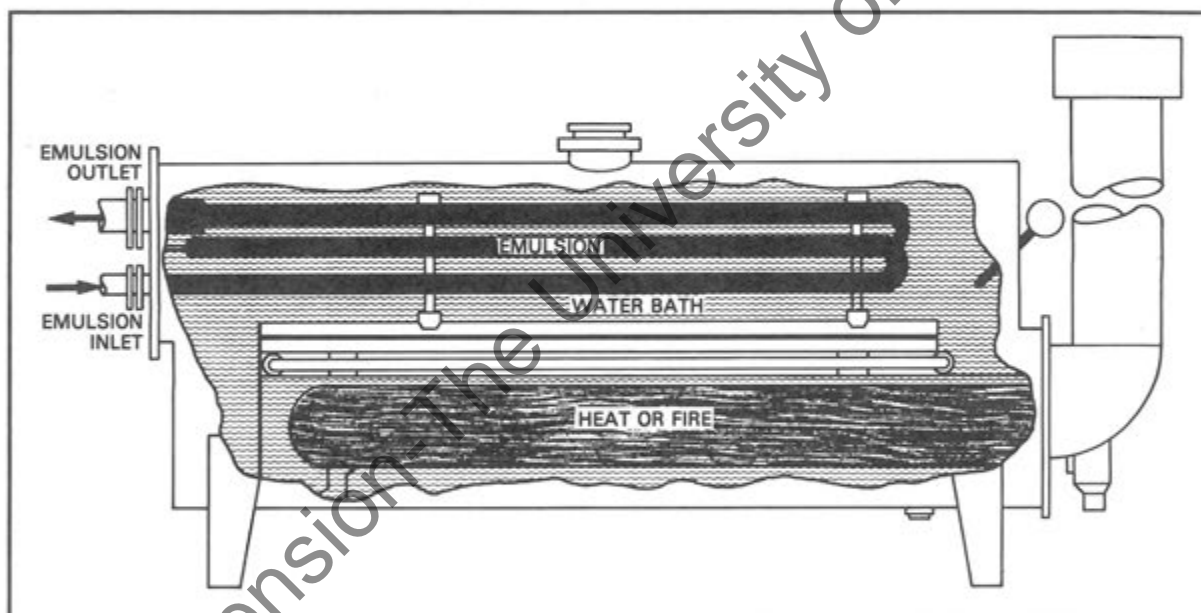


Figure 20. An indirect heater

Indirect Heaters

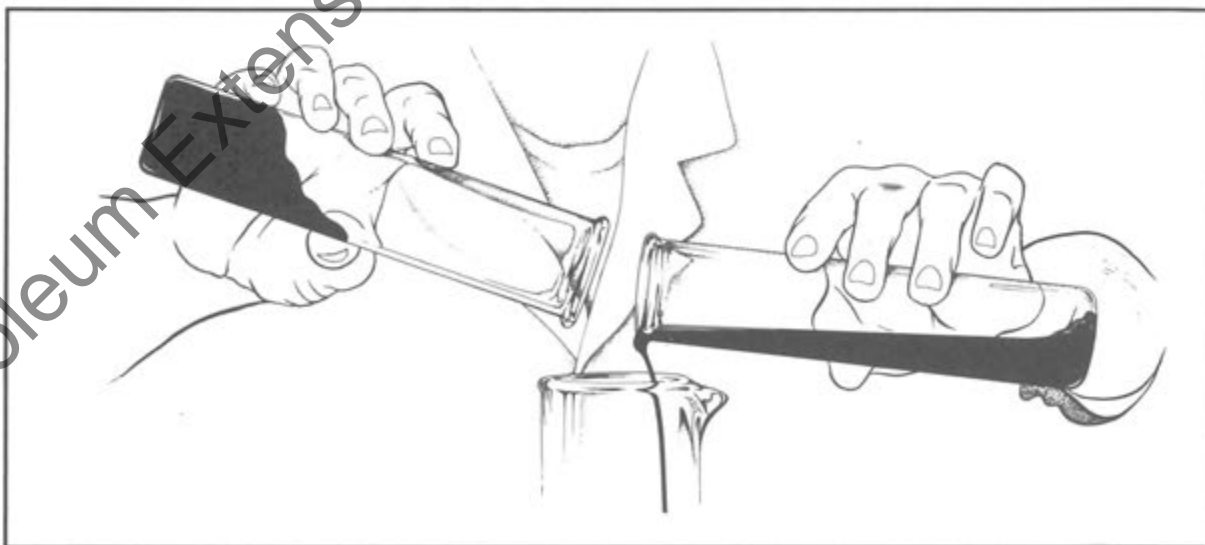
While a few direct heaters are still in use where separate heaters are employed, far and away the most common type of heater is the indirect heater. Unlike direct heaters, in which emulsion is put into direct contact with fire tubes, indirect heaters are constructed so that a hot water bath transfers its heat to the emulsion.

An indirect heater consists of three main parts: (1) the shell; (2) the flow-tube bundle; and (3) the fire tube (fig. 20). In operation, the shell is filled

flow tube are *safety drilled*, that is, a small hole on the outside of each bend is drilled about halfway through the metal of the tube where corrosion forces are most concentrated (fig. 21). When corrosion erodes through a safety drilling—about half of the flow tube's thickness—emulsion will leak through the corroded safety drilling and into the water bath. An alert operator will be able to see the leaking emulsion in the water bath and know that repair is required before continuing to operate the heater.

After completing Segment II, you should be able to —

1. Identify the conditions that determine when chemicals should be added in the treating process.
2. Identify the various points at which chemicals can be added in the treating process and recall the advantages and disadvantages of each.
3. Recall the ways in which chemical may be added in the treating process.
4. Recall the types of chemical feed pump, how they operate, and how they are maintained.
5. Identify the effects of temperature and settling time on chemicals used in treating.
6. Identify the reasons for the appearance of free water in an oil stock tank and list possible remedies.
7. Recall the reason for performing a bottle test on a normal and a reverse emulsion and how this test is performed.
8. Identify solvents that may be used to dilute a chemical demulsifier.
9. List the steps in a centrifuge test using slugging compound.
10. Recall the purpose of a ratio test and how one is performed.
11. Explain why reverse emulsion tests are becoming more common and how they differ from bottle tests used for normal emulsions.
12. List the steps for selecting the preferred chemical compound for treating an emulsion.
13. Explain what to do with the results of a bottle test.
14. Determine the best point at which to add chemical to the production system.



The Principles of Chemical Treating

In the early days of the oil industry, treating was a makeshift proposition, with each lease handled differently. Many operators depended on the people in the field to treat the oil and made no organized effort to determine which chemicals were most efficient at breaking emulsions. During this period, however, many chemicals were found, through trial and error, to be beneficial, including lye, hydrochloric acid, and soap powders. The chemical companies now familiar to the petroleum industry got their start experimenting with these chemicals. Today the principal business of a number of companies is the manufacture and sale of modern emulsion-breaking compounds and other oilfield chemicals. Several companies have research laboratories and a force of field engineers to assist the producer in selecting the proper chemicals and in other matters pertaining to treating done in the field.

For a chemical to work as an emulsion breaker in a water-in-oil emulsion, it must be able to deactivate the emulsifying agent that surrounds

the dispersed water droplets. Chemicals that are soluble or dispersible in oil and *surface-active* (i.e., they dissolve in the oil and work on the surfaces of the water droplets to cause them to break) are added in small amounts at some point in the treating system. Emulsion-breaking chemicals must also be polar materials; that is, they must be attracted to the emulsifying agents, which are also polar materials. This attraction is much like the action of two bar magnets being drawn to each other. The chemical contacts the emulsifying agent and, in effect, weakens it. When the freely moving water droplets in the oil collide, the droplets easily merge to form larger drops that will settle out. Figure 23 shows two samples of the same emulsion, one with and one without the addition of an emulsion-breaking chemical.

Chemicals used to treat reverse, or oil-in-water, emulsions differ from those used to treat water-in-oil emulsions in that they are *water soluble*; that is, they dissolve in water so that the chemical can contact the surface of the oil droplets suspended

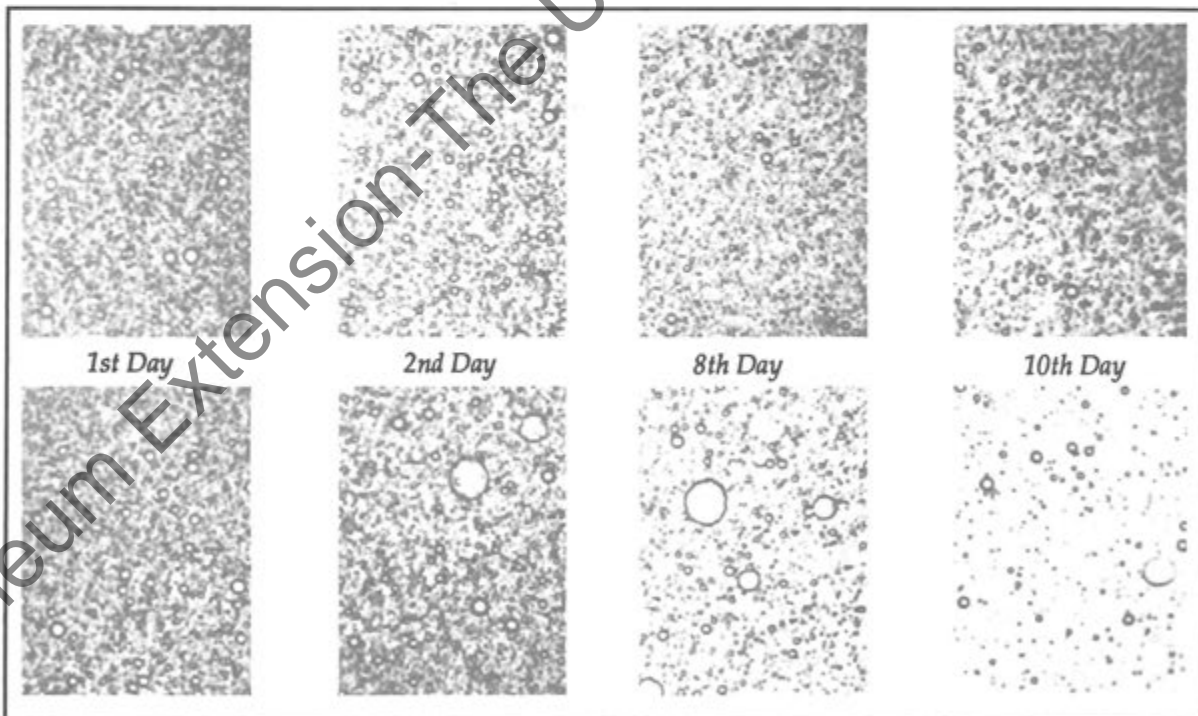
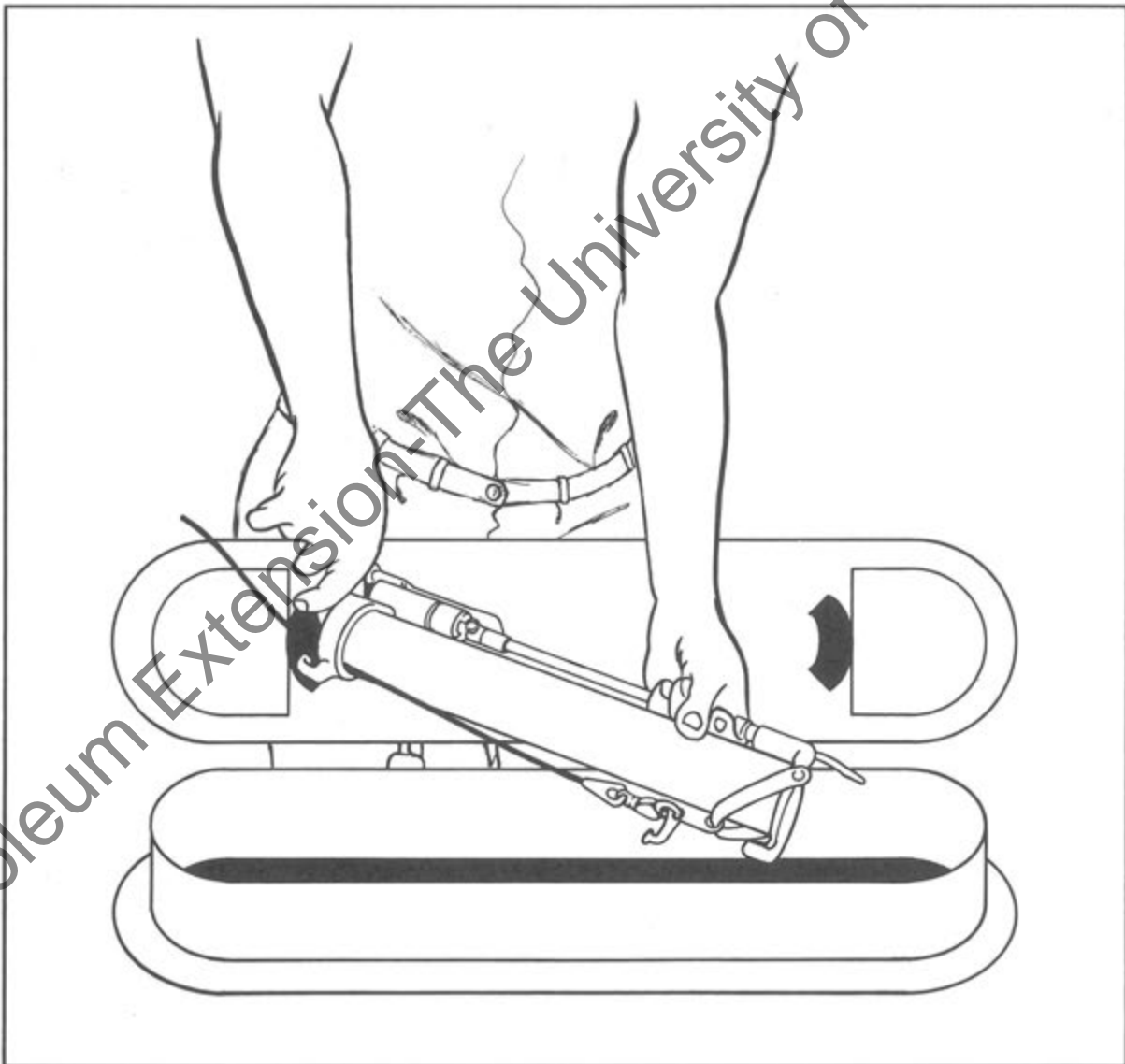


Figure 23. Two samples of the same water-in-oil emulsion maintained at the same temperature over a number of days. Demulsifier has been added to the lower sample. No chemical has been added to the top sample.

After completing Segment III, you should be able to—

1. Recall the differences between the types of heater-treaters and how they operate.
2. Explain how a central oil-treating system works.
3. List the basic principles of tank sampling and tell when a sample is acceptable.
4. List the types of sample and explain the differences between them.
5. Describe the API-recommended method of determining S&W in a sample.
6. List the API-recommended steps in saturating a solvent with water.
7. List the types and uses of treating cost records.



Treating with Heater-Treaters

A *heater-treater* (also called a flow treater or emulsion treater) is a device that combines all the various pieces of equipment used to treat an emulsion in one vessel. Thus, a heater-treater is the vessel in which the effects of chemicals, heat, settling, and, often, electricity are applied to an emulsion.

The Construction of Heater-Treaters

A heater-treater (fig. 32) is designed to include in one unit any or all of the following elements: oil and gas separator, free-water knockout, heater, water wash, filter section, stabilizing section, heat exchanger, and electrostatic field. A large number of modifications in the basic pattern of heater-treaters are available. Any of its functions may be emphasized, depending on the service for which it is designed. For example, a heater-treater may have greater free-water capacity or less heating capacity, and it may or may not have a *hay section*—a section packed with excelsior, which acts as a filter. In addition, each model may be available in a number of sizes to handle different volumes of well fluids and may be available in a vertical or a horizontal configuration. Some treaters are designed for use in extremely cold climates; others are designed especially to treat foaming oil. Selecting the right treater for any given set of conditions is a complex engineering decision that can be made only after a large number of factors are known.

Types of Heater-Treaters

Treaters can be operated at atmospheric pressure, but they often operate under low working pressure—from 5 to 50 psi—depending on the construction of the vessel and the type of controls used. It is often advantageous to use the treater as a low-pressure, second-stage separator as well as a treating unit. Where flow-line pressures are low, it can be used as a primary separator, thus eliminating the need for a regular separator. Use of the treater as a second-stage separator may increase the API gravity of the oil over that which



Figure 32. A vertical heater-treater

was obtained with other types of treating equipment and thus increase the selling price of the oil.

Vertical Heater-Treaters

In vertical heater-treaters, the emulsion usually passes through a heat exchanger, where it is preheated by the warmer outgoing clean oil. Then the emulsion enters the vessel, splashes over a pan, and falls downward through a downcomer tube. At the bottom, any free water in the emulsion falls out, and the emulsion flows upward through the water, which serves as a washing medium. The water is heated by a fire tube projecting into this compartment. After leaving the heated water wash, the emulsion rises into a settling space where water broken out of the emulsion settles out and falls back into the water

Automatic Central Oil-Treating Systems

In areas where one company operates a number of leases, all of which are established in a particular field, it is possible to employ an automatic central treating facility to handle the emulsion from most or all the leases. Figure 39 shows such a facility. Where applicable, a central treating plant can effect great savings. Traditionally, a treating plant was set up on each lease, but with the advent of automation and computerized production control, production from all leases can now be *commingled*, or mixed together, and then piped to a large central plant, where all the production is treated. Because no actual treating vessels are installed at the individual lease sites, one large facility replaces a number of plants.

In a typical central treating facility, the well or wells on each lease are produced into a header. The well fluids are normally diverted into production separators by use of automatically actuated valves (fig. 40). If a well is to be tested, the valve on the header can be directed automatically to divert the well fluids to a test separator. The automatic valves are usually equipped with diaphragm or motor actuators, which are, in turn, electrically operated by a solenoid that is controlled by an electronic computer. The separators are generally located at some convenient point on each lease; they may be either two- or three-phase (fig. 41), depending on the characteristics of the fluids being produced. Treating chemical is usu-



Figure 39. A central treating station with free-water knockout, electrostatic treaters, and stock tanks. A vapor recovery system, not visible, is also in use.

Sampling Procedures

All oil delivered to pipeline companies is subject to their testing. Therefore, to assure that the oil will be accepted, the producer should sample and test the oil in the same manner as prescribed by the pipeline company that purchases it. The procedures for taking samples and making water and sediment tests vary from field to field and company to company and must be agreed on by both the buyer and the seller. Any agreement found to be mutually acceptable serves the purpose.

The Measurement Coordination Department of the American Petroleum Institute has published standards for measuring, sampling, and testing petroleum and petroleum products. These standards reflect procedures that are considered acceptable in the absence of any specific agreement between the buyer and the seller of crude oil; they are not intended to conflict with or supersede any contractual agreement entered into between the buyer and the seller. The material for this chapter is drawn from API, *Manual of Petroleum Measurement Standards (MPMS)*, chapter 8, section 1, *Manual Sampling of Petroleum and Petroleum Products*, and chapter 8, section 2, *Automatic Sampling of Petroleum and Petroleum Products*.

The basic principle of any sampling procedure is to obtain a sample or a composite of several samples that is truly representative of the oil in a tank or other container. The sample can then be tested to determine properties that have a bearing on the measurement of the oil sampled. Two basic sampling methods are available: tank, or manual, sampling; and automatic sampling. If, however, a tank's contents are not homogeneous from the top to the bottom, or if certain other conditions are not met, automatic sampling is recommended. For tank sampling to be acceptable, the contents of the tank must be homogeneous and (1) the tank must contain a heavy component (such as water), which clearly separates from the main component, (2) the tank must be equipped with either a swing suction or a weir on the outlet that prevents shipment of the heavy component, and (3) the tank samples must be taken so that none of the heavy component is

included. In addition to automatic sampling, API recommends three manual procedures suitable for sampling tanks that contain crude oil: thief sampling, bottle sampling, and tap sampling.

Thief Sampling

Probably the most common method of obtaining samples of crude oil in lease tanks is by means of a thief. A *thief* is a round tube, with a uniform cross section, that has a capacity dependent on the size of the sample required (fig. 46). It is suspended by a chain or rope at its upper end; a

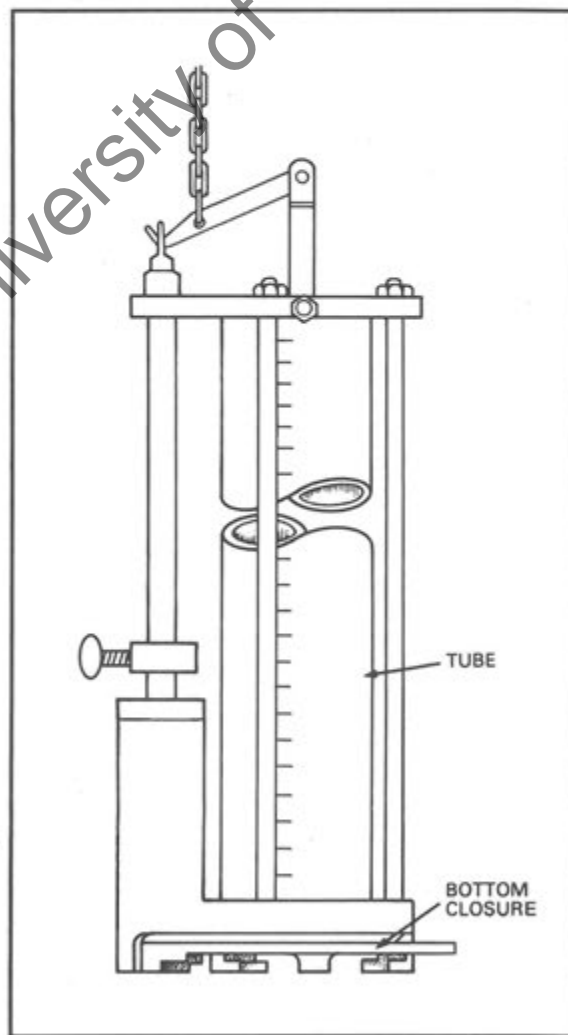


Figure 46. A tubular tank thief

Testing for Sediment and Water

After a representative sample has been obtained, the next operation is to determine the percentage of S&W present in the sample, thus ensuring that the oil meets pipeline specifications. Or, as stated in API, *MPMS*, chapter 10, section 4, *Determination of Sediment and Water in Crude Oil by the Centrifuge Method (Field Procedure)*, second edition, May, 1988, "A determination of sediment and water content is required to determine accurately the net volumes of crude oil involved in sales, taxation, exchanges, inventories, and custody transfers. An excessive amount of sediment and water in crude oil is significant because it can cause corrosion of equipment and problems in processing and transporting and may violate federal, state, or municipal regulations." The testing method presented in this chapter is paraphrased or quoted from *MPMS*, chapter 10, section 4.

The most common method of determining the percentage of S&W in treated oil on a lease employs a centrifuge. In brief, the procedure is to place known volumes of crude oil and solvent (water-saturated, if required) in a centrifuge tube and to heat them to $60^{\circ}\text{C} \pm 3^{\circ}\text{C}$ ($140^{\circ}\text{F} \pm 5^{\circ}\text{F}$). For some waxy crude oils, temperatures of 71°C (160°F) or higher may be required to melt the wax crystals completely so that they are not measured as sediment. If temperatures higher than 60°C (140°F) are necessary to eliminate this problem, they may be used with the consent of the parties involved. If water saturation of the solvent is required, it must be done at the same temperature. After centrifuging, the volume of the sediment and water layer at the bottom of the tube is read.

Solvents

Solvents decrease the viscosity of the sample to assist in the separation of S&W from the oil during centrifuging. Solvents that API recommends include kerosene, Stoddard solvent, toluene, and xylene. Toluene and xylene are recommended for S&W determinations involving asphaltenic crude oils. Also, if necessary, a demulsifier may be added to the sample to promote separation of

water, to prevent water from clinging to the walls of the centrifuge tube, and to enhance the distinctness of the water-oil interface.

API recommends that toluene and xylene be saturated with water, since water in the oil sample can go into solution with these two solvents if they are not water saturated. If water in the oil sample goes into solution, erroneous S&W readings result. To saturate a solvent with water, the method API suggests follows.

1. Fill each of two centrifuge tubes to the 2-ml (4-part) mark with water and then to the 100-ml (200-part) mark with the solvent to be saturated.
2. Stopper the tubes and shake vigorously for 30 seconds (sec), holding the tubes below eye level to protect the eyes should solvent come out of the tubes. Loosen the stoppers.
3. Place the tubes containing the water-solvent mixture into a sample preheater or heated but nonspinning centrifuge maintained at a temperature of 60°C (140°F) for a minimum of 30 min. Be sure the stoppers in the tubes are loosened to allow vapors to escape.
4. Inspect the water-solvent mixture for suspended water droplets before use. If any suspended water is visible, the tubes must be centrifuged at a temperature of 60°C (140°F) for 5 min at a speed sufficient to give a relative centrifugal force of 500 at the tube tip. Table 3 shows rotation speeds necessary to produce the required relative centrifugal force for centrifuges of various sizes. An equation may also be used. If the diameter of the swing is in mm (*swing diameter* is the distance between the tips of opposite tubes when the tubes are in their rotating position), the equation is

$$\text{rpm} = 1,135 + rcf + d.$$

If the diameter of the swing is in inches, the equation is

$$\text{rpm} = 265 + rcf + d.$$

5. Use the top 50 ml (100 parts) of the mixture from each tube for test purposes. Take particular care not to pour any of the free water in the tip of each tube into the sample.

Treating Oilfield Emulsions

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