Separation in Oilfield Operations

"Myths versus Realities"

Innovation has been slow in the oil and gas industry. A key reason is the paradigm "Because we've always done it that way." Together, we can change that!

A Technical Paper

Prepared for

Facility Engineers and Designers

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EXECUTIVE SUMMARY

It should not be a surprise that our 130-year-old industry is filled with myths from the past. For instance, in 1891 John D. Rockefeller, owner of the largest oil company in the world, is quoted as saying that no one would ever find oil west of the Mississippi River. In 1901 the world's largest oilwell in Spindletop, near Beaumont, Texas, flowed over 100,000 barrels of oil daily. Rockefeller's statement was a myth, with no basis in fact. The reality is that oil exists everywhere around the world.

It is no myth that in business, knowledge is everything! And yet, as Rockefeller showed us, there has always been a knowledge gap in the oil business. Past industry practices were woefully deficient. Many current standard practices are based on past experiences which are based on the myths of past paradigms. Newer concepts are often overlooked in favor of older methods because "We've always done it that way!" It is no myth that change is risky. But the reality is that the time has come to try something new, different, and develop something better.

This paper attempts to improve the readers' understanding of the differences between past myths and today's realities. Currently, the so-called "shale oil boom" has taught us how to distinguish the two in today's oilfield operations. The hope is that this will help us attack the paradigms of the past in the hope that we can be more open-minded, creative, innovative, and productive.

This paper prompts us to recognize the myths of past upstream operations and the realities of today's technical opportunities. Together we will learn some of the myths that created key myths of the past, and some of the real opportunities we must enhance today's operations. Overcoming the myths of the past means we will more successfully meet the realities of all future opportunities.

BACKGROUND HISTORY

The practice of oil-water separation began at the site of the industry's first oil well in Titusville, PA. There, on Saturday, August 27, 1859, after months of drilling, oil pioneer Edwin Drake completed the world's first oil well. He used an old bathtub to separate his oil from the water the well also produced. The water was drained off into a nearby creek.

My, how things have changed! But as much as things change, they stay the same. Separation remains a must, but the methods have changed since 1858.

One reality is that in the decades since Drake's first well the oil industry has experienced an unprecedented increase in water production, particularly since World War II. Most oil wells now produce ten to one-hundred times more water than oil. Producing and separating conditions have changed dramatically. Where in 1858 the emphasis was on separating lesser amounts of water from Drake's precious oil, today we often focus on separating small amounts of our precious oil from very large quantities of produced water.

Some believe that "separating is separating." However, the separation of water from oil is a completely different process from the separation of oil from water. In fact, these processes are exact opposites! Systems designed to make one fail at the other.

Once this is understood it may become apparent, even obvious, that the process facilities used to separate water from oil are not suitable for the separation of oil from water. This is a key concept. The myth that "separating is separating" will be explored in the pages that follow. The many realities of separation will be identified as well.

SEPARATION FUNDAMENTALS

The early days in the oil industry were dominated by hard, difficult work. Many early oilfield workers had a limited education; often sixth grade or less. However, most of them were raised on farms where hard work and practical problem solving was a must. So, while they may have had limited educations, they were clever and innovative. They were prone to the concepts of trial and error.

They needed to remove impurities like water, rocks, and dirt before oil buyers would pay for their oil. This need prompted a trial-and-error effort to discover a way to remove small amounts of impurities from produced crude oil. The first solution was settling tanks.

In the 1800s most oilfield tanks were made of wood. They were constructed like wine barrels, though larger, and building them demanded highly skilled craftsmen. So, the tanks were also very expensive. The fewer, the better!

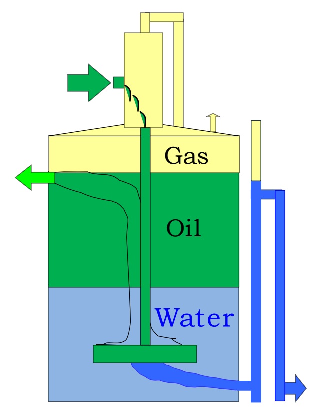
In the beginning they flowed oil and impurities into tanks one at a time and let the contaminants settle out. The tanks were built in rows. They would fill the first tank in the row and wait for the contaminants to settle out. Once the first tank was full, they would fill the second, the third, and so on. When the oil in the first tank was clarified it was sold. The next day's oil would be redirected back to it, and so on. In light oils there might be a row of three tanks; in heavier oil a row of ten or more tanks might be needed to give the contaminants enough time to settle out of the oil.

To reduce the number of tanks a few clever oil workers began experimenting with ways to use fewer tanks. They discovered that they could flow oil and contaminants through tanks and separate contaminants if they 1) provided a mechanism to separate gas from liquids, 2) kept a thick layer of oil inside the tank at all times, and 3) kept a thinner layer of water in the tanks at all times, and 4) forced the contaminated oil to flow up through the water in the bottom of the tank, and 5) up through the oil above the water, taking the cleaned oil out of the tank near the top.

The question then became, "how do we keep the layers at constant levels?" In 1880, the answer to questions like this were not obvious. So again, these innovators used trial and error to find the solution. They developed what they called a "water leg."

The water leg was two joints of vertical pipe connected at a point below the top of the oil layer inside the tank, and above the top of the water layer inside the tank.
Water would flow into the water leg from the bottom of the tank, up through the first vertical leg, spill over into the second leg and fall to its bottom. From there water would flow on to the next tank, or pit, or disposal well.

The inlet water leg pipe was always extended to an elevation a foot or so above the sidewall height of the tank. The top of this pipe would remain open to atmosphere to equalize its pressure with the tank, which is also open to atmosphere. They discovered that the oil-water interface level inside the tank was set by the height of the water spillover between the two legs of the water leg.



The Original Gunbarrel

They also installed the two-pipe water leg assembly so it could be tilted left or tight to raise or lower the spillover elevation. Tilting the water leg changed the level of the oil-water interface inside the tank. This was clever, and very effective.

And finally, before waterflooding, water legs would be fabricated from small diameter pipe (2" to 4"), since oilwells in most oilwells produced oil no more than 10% water.

The use of water legs was critical in establishing and maintaining a constant oil-water interface. The height of the spillover typically fixed the interface at about 30% of the overall tank height. This left the remainder of the tank filled with oil. This oil space could be adjusted up or down by tilting the water leg. Increased oil allowed for more time for contaminants to fall out of the oil so could be sold.

Early oilfield workers knew that water and oil do not mix. Their experimentation showed them that when oil containing some water flowed through a layer of water the amount of water in the inlet oil was reduced. These common-sense concepts led to the development of the water leg and the gunbarrel (wash) tank design where the emphasis was always on improving oil quality. In the early days there was no concern whatsoever for water quality since water was a waste product.

The gunbarrel with its water leg was the industry's first crude oil dehydrator, and it is still an often-used crude oil dehydrator.

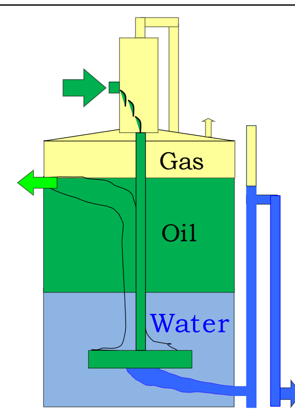
WHY THE TERM "GUNBARREL"?

The term "gunbarrel tank" originated in the 1880s when guns were a part of everyday oilfield life. As workers looked at the top of these tanks, they saw what resembled the barrel of a gun. This now-outdated experience created the term "gunbarrel tank."

It is believed that the gunbarrel concept was first conceived in the mid-to-late 1870s with mixed results. In the years that followed, the size of these tanks increased as oil volumes increased. As they experimented with different tank configurations, tank height grew too, until the "standard" gunbarrel design performed as desired.

However, as the industry evolved throughout the 20th century and into the 21st century, gunbarrel designs remained the same. And today, regardless of design deficiencies, gunbarrel tanks are still in use. Their performance is far from ideal when used in todays' high water cut applications, but because of the "we've always done it that way" paradigm, many upstream operators still order new gunbarrels/wash tanks for their oilfield operations. Therefore, this paper will help explain why and how these tanks perform.

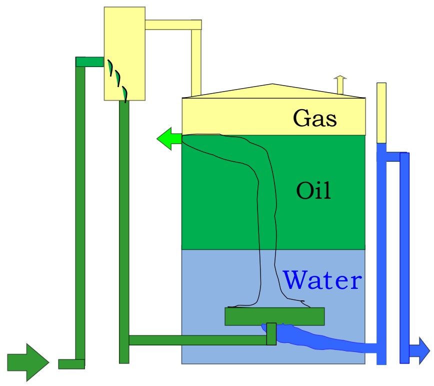
LET'S SEE HOW IT'S MADE



The Original Gunbarrel

As produced oil, water, gas, and any solids flow into these specialty tanks the raw fluids enter a degassing chamber referred to as the "gas boot" (aka: "degassing boot"). In some cases, this is a vertical pipe located on top of the tank. In others, the gas boot is installed on top of an external pipe which feeds raw production into the tank. Gas flows up inside the degassing boot and is piped off to either A) the gas phase in the tank through an equalizer pipe, or B) to atmosphere, or C) to a vapor collection piping system feeding a vapor recovery unit or a low-pressure flare.

Whether the "gas boot" is internal or external, it is connected to a smaller "downcomer pipe" which extends down to within a few feet of the tank bottom. Gas separates in the top of this assembly. Oil and water flow down through the downcomer pipe and exit into the tank near its bottom. A horizontal baffle (aka: "spreader") is attached onto the bottom of the downcomer just a few feet above the tank bottom. When the gas boot and downcomer pipe are installed outside the tank, the downcomer is piped into the center of the tank and extended to terminate immediately underneath the spreader.



The Original Wash Tank

A water leg is installed on the outside of the tank. Its spillover elevation is set so the lower one-third of the tank is filled with produced water and the remainder of the tank fills with oil. As flow from oilwells begins, the spreader distributes the produced fluids into the water phase. Solids and emulsions (aka: BS&W) separate from the oil. Separated water is absorbed into the water layer and solids settle onto the bottom of the tank.

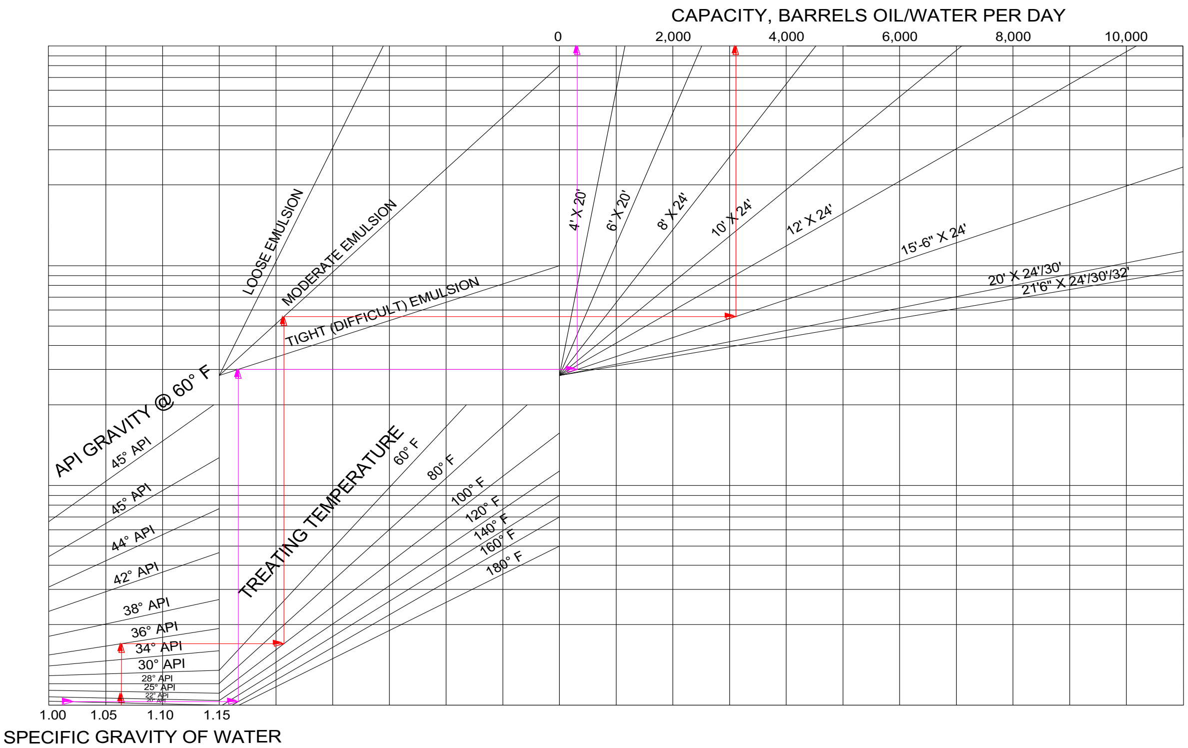
In the 1800s and early portion of the 1900s the water legs were designed so the tanks would contain 2/3rds oil and 1/3rd water. This way the oil would have sufficient retention time for all water to separate from it. When this didn't happen as predicted, operators installed larger and/or taller gunbarrel tanks or modified fluid heights until they functioned as desired.

At the bottom of the downcomer pipe was the fluid spreader. The spreader was designed like an upside-down pan with serrated edges on the open portion of the pan to encourage uniform distribution of inlet fluids into the water layer. The serrations were "V" shaped notches much like saw teeth. The V-notches "metered" the flow of raw inlet oil into the water phase to maximize their respective contact.

From the very beginning the design philosophy for these tanks was to "wash" the contaminants out of the crude oil so it could be sold without a pricing penalty. When these tanks were designed with top mounted degassing boots and internal downcomer pipes, they were referred to as "gunbarrel tanks." When they were designed with external degassing boots and external downcomer pipes, they were referred to as "wash tanks." Regardless, they were intended to perform identical functions.

GUNBARREL SIZING

In the 1800s oil operators concluded that gunbarrel tank sizing had to be based on the supposition that crude oil needs from eight to twenty-four hours of retention time to dehydrate, depending on its density (API gravity). Decades of observation had determined that the retention time needed was related to the inverse of the oil gravity. That is, the lighter the oil the less time it needs to dehydrate. From this it became clear that gunbarrels could be smaller for light oil than for heavy oil where tanks had to be much larger to achieve the same oil quality results. Finally, in the 1930s, previous decades of experience were converted to nomographs like the sizing nomograph below.



By the 1970s several R&D studies indicated that the fluid distribution theories of gunbarrel tanks were mostly invalid. These studies showed that raw crude oil exiting serrated spreader immediately oil wets its surface and the outer surface of the downcomer pipe. Once oil wet, the raw oil and emulsion naturally and preferentially flows up the outer surface of the spreader and the downcomer pipe until it reaches the top of the oil layer. Once there, it disengages from the wall of the downcomer pipe and flows across the top of the oil layer to the oil outlet nozzle, spending minimal real retention time in the oil layer. Needless to say, this result was quite unsettling.

It was also found that in higher oil flow conditions some of the oil would disengage from the spreader edge in large droplets or globules and distribute horizontally out into the water layer, but only for a few feet, at best. These oil droplets then flowed rapidly and vertically through the water layer, through the typical emulsion layer just below the oil layer, and into the oil phase. From there little, if any, horizontal distribution occurred, and the oil flowed diagonally in the path of least resistance to the oil outlet nozzle, circumventing the bulk of the tank's volume and potential retention time. The flowing oil only encountered or mixed with a ridiculously small portion of the oil stored in the tank.

In many cases the inlet crude was found to only reside in the oil phase for a few minutes. This finding refuted the old design philosophy of sizing based the 8-24 hours of crude oil retention time … another long-standing paradigm! It also seemed to refute the nomograph above.

Finally, it was proven that the when the crude was "washed" through the water layer under the oil, the emulsion content of the inlet crude increases in inverse proportion to its API gravity. In this case the emulsion concentration of heavier inlet crude actually increases as the heavier crude flows through the water layer.

RETENTION TIME VS. SEPARATION

That earliest gunbarrel/wash tank design remained unchallenged for over one hundred years! Then in the early 1970s the standard design was finally challenged. The 1970s were years when the unusually high price of crude oil brought on by the Arab oil embargo infused the industry with extra income. Some of that income was funneled into field and laboratory research to study the relative efficiency of more prevalent oilfield equipment. The results for the gunbarrel/wash tank design were startling and disappointing, to say the least!

Fluid flow and retention time studies were conducted on standard separators, gunbarrels, wash tanks, free water knockouts, heater treaters, and oil-water skim tanks. The results showed that the distribution efficiency (aka: hydraulic efficiency) of these old equipment designs was extremely low. Testing proved that most ranged from less than 1% to 3%, with very few exceeding the 10% range.

In the past, bigger had been thought to be better. If a tank performed poorly, another larger tank was ordered to replace it. However, formal R&D department studies refuted that concept. In most cases, too big was proven to be as bad as or worse than too small! These same studies also identified non-uniform flow characteristics in most tanks and vessels which resulted in low hydraulic and separation efficiencies.

These studies also proved that all fluids predictably take the path of least resistance. Not surprisingly fluids flow through all vessels in the shortest flow path between a vessel's inlet and its outlet. This was something of a revelation since it had been presumed that fluids entering and tank of vessel distributed uniformly and flowed like a plug or piston through the entire vessel cross section. In the middle of the 20th century this was something of a revelation to a hundred-year-old industry!

In addition, these studies proved that both the flow path and fluid velocity in the flow path determine the degree of separation. They also proved that these features are rarely constant since operating conditions are also rarely constant.

The revelation resulting from this work was that "When the velocity of the predominant fluid exceeds the separation velocity of the secondary fluid, or the solids in it, most separation ceases!"

This revelation confused many of those involved in these studies since it completely refuted the age-old belief (paradigm) that all existing separation systems and process vessels functioned efficiently!

The hydraulic efficiency of field equipment was also tested during the "oil embargo boom years". The results in the field were equally disappointing. It was particularly true for gunbarrels/wash tanks. But when the Arab Oil Embargo ended, too much of the research results just gathered dust throughout the succeeding decades.

AN INDUSTRY IN TRANSITION

During its first eighty-nine years the oil industry was focused on finding new oil reservoirs. Drilling a new well could take months, sometimes years. Drilling was hard work. Most oilfield workers came from family farms. They often had less than a high school education, but they were clever and practical.

Oilwells in the 1800s produced little or no water. While it is almost unbelievable today, when an early oilwell in the late 1800s began producing water it was plugged and abandoned, and a new well was drilled to take its place. This practice continued at least until World War I.

As the industry prospered, so did the educational level of many of its employees. In the late 1890s colleges and universities began offering degrees in oil related disciplines. Petroleum geologists announced that oilwells produced only about 5-8% of the oil in a typical oil reservoir. To recover some of what was left, industry began installing oilwell pumping systems on old oilwells to pump out more oil. Produceable volumes increased, but geologists reported that 75% of the earth's oil remained underground even after pumped wells declined to the end of their life. No one knew how to get the rest of the oil out of the earth, and the industry slumped into a recession.

Finally, World War I prompted the need to produce more oil to fuel war ships and created another oil drilling boom! Drillers tried feverishly to keep up the demand for more and more oil during the war years. Then, as World War I ended, the industrial age flourished and the economy began to improve. More oil was needed. Geologists, dissatisfied with a meager 25% oil recovery, began experimenting with new and different techniques trying to improve drilling success rates and overall oil recovery. Soon World War II created another "oil drilling boom" just as it had during WWI. During this boom, some oil companies began experimenting with the concept of waterflooding.

From this experimentation a new technology known as "secondary recovery" was developed and perfected. Secondary recovery (aka water flooding) allowed producers to re-enter older fields and recover unprecedented quantities of oil left behind during primary recovery from known formations using waterflooding to bolster reservoir pressures and to drive oil left in place into existing producing wells. Some waterflooded oilfields produced more oil each day than they had during primary production! It was a panacea!

However, while oil production grew dramatically in fields being waterflooded wells also produced unprecedented volumes of produced water. This was something entirely new!

Overnight, water cuts (water-to-oil ratios) climbed into and past the "greater than ninety percent water, less than ten percent oil" range. This created a brand-new challenge. The 87-year-old industry had never experienced this before.

New and higher water volumes created a new challenge for all oil producers and all support organizations as well. Most oil was separated in tanks developed in the 1880s. These were called "gunbarrels" or "wash tanks." Suddenly, water leaving these tried-and-true process tanks now had excessive quantities of oil, and worse, oil leaving them had such high concentrations of water that the oil exceeded the quality specifications of all buyers. Overnight these gunbarrel (aka: wash tanks) were performing so poorly that something had to change!

By 1950 it was clear that waterflooding was here to stay, but most process equipment and separation systems had been designed before waterflooding, and many were now out of date! Reacting to this reality many of the larger oil and equipment companies began to shift some of the focus to their R&D efforts. The needs were clear, but the focus remained cloudy. The paradigm that existing systems and processes had always worked was hard to overcome. The overall mindset was that since existing processes had worked so well in the past, these same designs continue to work. The familiar paradigm of "we've always done it that way" was difficult to get past. So, while water flooding dramatically improved oil recovery for the next several decades, many of the much-needed process and equipment design changes went unexplored.

Water flooding reached its pinnacle. Secondary recovery was augmented with chemicals like surfactants and CO_2 during the embargo years when oil prices justified higher cost experiments which further enhanced oil recovery. And, while these experiments were technical successes, recovering more oil from reservoirs than ever before thought possible, most were economic failures. And all exacerbated the high water cut issue! More water with more reservoir fines and chemical residues enhanced the need to develop systems to separate less and less oil and more and more contaminants from produced water.

By 1960 most major oil companies believed they had discovered all the major oilfields in the USA. So, as waterflooding matured many domestic oilfields "watered out," and the industry shifted its focus to international oil and gas operations. They felt they needed to develop new opportunities in the Middle East, the North Sea, and other overseas prospects to survive. This refocusing had an immediate effect on the domestic oil industry. While Tulsa, Oklahoma had been the unofficial "oil capital of the world" for the decades before 1960, more and more oil companies began focusing on international opportunities and many relocated their headquarters from Tulsa to Houston where they could easily access global airline flights.

Overseas operations flourished. International oil revenue increased as never before. Almost overnight countries like Saudi Arabia, Iraq, Iran, and Venezuela became dominate forces in the oil industry.

THE "BOOM" AND BUST CYCLE … AGAIN

Then in 1973, a group of these oil-rich countries banded together to create an oil monopoly to control the global supply of crude oil. The monopoly was "Organization of Petroleum Exporting Countries," or "OPEC." OPEC raised the price of the oil by 70%, and then embargoed the export of their oil to the USA in retaliation for our involvement in the Gulf War. Prior to the embargo OPEC had supplied 35% of the crude used in the USA.

To offset the oil shortage caused by the embargo the domestic oil industry began drilling for US oil at a much-accelerated pace. The need for more crude oil created another "oil boom" in the USA. Domestic crude prices rose from $3.45/barrel to over $45/barrel by 1982, but when OPEC finally lifted the embargo, the "boom" came to an end. It had lasted twelve years, but in 1985 the price of oil declined back to below $10.00/barrel. Drilling rigs were idled. R&D departments were closed. Over 80% of all oil workers were laid off. Service companies failed. The decline decimated the domestic oil industry, and it entered a period of decline ("bust") that lasted from until the after the turn of the century, after the banking crisis of 2008, and until the beginning of the "shale oil boom" of 2010.

TRANSITION MEANS GROWTH

To recap, the world's thirst for crude oil began with Drake's first well in 1859. That first well produced a meager twenty-five barrels of oil a day, but by 1879 oil production had grown to over 16,000. Then In the 20th century the industry was up and down. The Spindletop well produced 100,000 barrels of oil and became the largest oil producer ever. World War I propelled the oil industry further. Developments like rotary drilling, Getty's Tri-Cone drill bit, Standard Oil's "thumper," and KBK's DFSD® and HWSB® process tanks helped propel the industry into the 21st century. Today US oil production is at an all-time high and exceeds 13,250,000 million barrels each day. The USA is energy independent once again!

Throughout the sixteen decades since Drake drilled the world's first oilwell the oil industry has learned a lot. The purpose of this paper is to recap what has been learned, to separate the myths from the realities, and to explain the subject of oilfield separation from its basics to the science behind them. So, let's start with the basics.

A NEW SEPARATION PARADIGM

From the studies conducted in the 1970s it became clear that any water in the oil phase had to separate in a matter of minutes rather than in a matter of hours as previously thought. And, since the age-old belief that 8-24 hours of oil retention time was proven to be invalid, it became obvious that most gunbarrel tanks were vastly oversized. It was also obvious that they all had extremely low actual retention time (hydraulic efficiency). It was finally crystal clear that for tanks and vessels to be designed to maximize retention time, they had to be hydraulically efficient. This translated to two primary conditions:

1. Uniform inlet fluid distribution.
2. Uniform effluent fluid collection.

At this point, oilfield vessel designs began to shift. Some designers looked for new methods of increasing the distribution of oil. It was believed that this would result in smaller gunbarrel designs, and a smaller investment in the oil stored in them.

To test these theories clear plastic scale models were built and fitted with various internals so results could be observed and documented. While the results were very encouraging, each investigator was also surprised at how inefficient the old original gunbarrel design was.

It became quite clear that when inlet fluid distribution is more uniform the result was to dramatically increase the actual water and crude oil retention times. Increased separation was the result … but the question was, "How much?"

As studies continued it was discovered that it was possible to achieve uniform distribution and when this was accomplished the real retention time increased by factors of from 10 to 35 times!

Furthermore, and equally surprising, it was also found that real process throughput and separation efficiencies increased even more when the inlet crude and emulsion is NOT washed through the water phase, but instead is introduced into the emulsion rich layer immediately above the water-oil interface. These studies proved that both naturally occurring and artificially added emulsion breaking chemicals (aka demulsifiers) tend to concentrate in this emulsion-rich layer. These chemicals have the effect of reducing the surface tension of droplets, promoting coalescing (the growth of droplet size), and therefore vastly improving separation.

Many of the earliest oilfield workers had a sense of the separation of oil and water, though they could not quantify it. But after World War I the industry began employing more and more highly educated people and finally the science of separation was used to define and quantify the physics of separation using Stokes' Law.

SEPARATION BASICS - STOKES' LAW

From the time of Drake's first oilwell separation had been a "black art." It seemed like magic to the earliest oilfield worker. Nut in fact, separation has its roots in physics. The static separation of two or more immiscible fluids (fluids that are not soluble in one another), and/or suspended solids, can be predicted by applying Stokes' Law of physical separation. In 1839, before Drake drilled the first oilwell, George Stokes, a physicist, identified the three components of separation: gravity, density difference, and viscosity. He published his works, and they were immediately accepted by the scientific community of his time. Stokes' Law of separation became the guidepost for predicting separation, at least in the scientific community. It would take another 75 years for Stokes' law to find its way into the oil industry.

An example of using Stokes' Law is predicting the separation of gravel dumped into a tank of water. The tank is "static," which means there is no motion inside. Using Stokes' Law anyone can calculate how long it will take for the gavel to reach the bottom of the tank. It is obvious that the gravel will settle to the bottom because gravel is heavier than water. It is logical that the larger, heavier pieces of gravel will settle (separate) faster, and the smaller, lighter pieces will settle (separate) slower. An understanding of this simple principle is a good beginning to understanding "gravity separation" and Stokes' Law as applies to oil-water separation in the oil industry.

In the early days of the oil industry produced fluids were kept static (non-moving) in tanks or barrels or pits until impurities separated. So, a good understanding of the concepts in Stokes' Law is critical to the understanding of separation.

STOKES' LAW

Stokes' Law was published in 1851. It identified the separation velocity of a rising or falling fluid or particle under static conditions from any other fluid using the following formula:

$$V_s = \frac{2}{9}\,\frac{r^2 g(\rho_p - \rho_f)}{\eta}$$

Where:

r is the particle radius
η is the fluid viscosity
V_s is the particles settling velocity, in feet per second
g is the acceleration of gravity
ρ_p is the density of the main fluid
ρ_f is the density of the separating fluid

Stokes' postulated that if the particles fall through a viscous static fluid by their own weight, then he could derive their settling velocity by equating the frictional force with gravitational force.

To relate Stokes' Law of non-moving fluids to the dynamic, ever-moving separation conditions encountered in most oilfield separation systems, Stokes' Law needed to be modified to account for the differences between static fluids and fluids in motion. A generalization of the calculus involved was necessary and resulted in what is now referred to as "modified Stokes' Law," as follows:

$$V = \frac{Cr^2(d_1 - d_2)}{N_1}$$

Where:

r is the particle radius
η is the fluid viscosity
V_s is the particles settling velocity, in feet per hour
g is the acceleration of gravity
ρ_p is the density of the main fluid
ρ_f is the density of the separating fluid

This version of Stokes' Law focuses on immiscible phases separating while in motion. When more than two phases are present, each must be calculated independently of the others.

Modified Stokes' Law states that the velocity (V) of separation of one of the phases from the other is determined in feet per hour, and is equal to the density difference of the two phases ($d_1 - d_2$) times the square of the size of the fluid/solid particle (r^2) times the gravitational constant (C), all divided by the viscosity (N) of the continuous phase.

Particle Size is the Key

In both versions of Stokes' Law each of the formula variables has a decided impact on the rate of separation. The greatest of these is the size of the particles, or the size of the droplets targeted for separation. Stokes' formula shows us that the relationship between particle sizes is not linear (one-to-one), but exponential (the square) of the droplet or particle size.

What this means in the real world is that as the size of a particle or droplet increases, its separation velocity is squared.

For instance, as the size of a droplet triples, the separation velocity increases to nine times as fast. As size quadruples, the particle separates sixteen times as fast, and so on.

The inverse is also true. A reduction in size by half results in a separation time four times longer. A reduction in size to one-fourth the original size results in a separation time sixteen times longer, and so on.

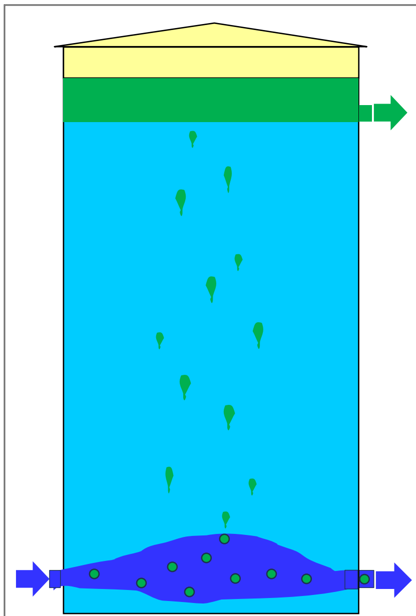
This is the key, and most important concept of Stokes' Law!

ESTABLISHING SEPARATION

It is obvious that we need to design all oilfield separation facilities so they separate. Eliminating mixing energies is a start. What is not so obvious is how to accomplish this.

Most types of oilfield tanks and vessels have been tested to determine whether or not they separate as expected. Many have failed the test because the designer failed to recognize the simple fact that fluids flow through the paths of least resistance. The typical "skim tank" in the graphic below a classic example.

This graphic is a typical oilfield tank used as a skim tank. This tank has no internals. So predictably, fluid entering the tank inlet on one side flows directly to the tank outlet on the other side. This is consistent with flows through the path of least resistance. Since there is no mechanism for the inlet fluid to distribute in the tank, retention time is minimized. The inlet water never slows down, so most oil droplets and solids in it never separate.



Inefficient Oilfield "Skim" Tank

This is a classic example of the fact that, "When the flowing velocity of a fluid is greater than the Stokes' Law separation velocity of the contaminants in it, most of the contaminants cannot and do not separate." Instead, most of the contaminants remain in the mainstream as it leaves the tank.

Nevertheless, we must separate contaminants from produced oil and water. We should capture remnant oil from water streams, thereby generating a valuable income stream. With oil and solids removed, wastewater can be injected without plugging.

Most droplets and particles in produced fluids are larger than 500 microns and separate very rapidly. Stokes' Law shows that when they are larger than 150 microns, they are rarely a problem in the real world. However, when they are smaller than 150 microns, they separate at such a slow rate they cause processing difficulties. Furthermore, when droplets/particles are smaller than 25 microns, they are in a "stable" state of suspension. In that condition they separate so slowly that any fluid motion keeps them suspended and most do not separate at all.

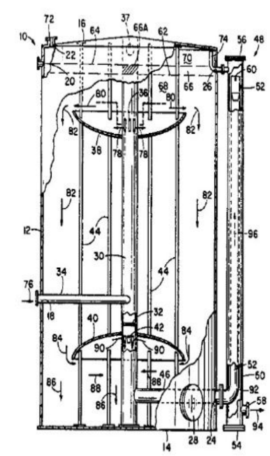
One of the ways to increase the size of droplets or solid particles is with a properly formulated coalescing chemical applied at a proper dosage rate. While these oilfield chemicals often help resolve emulsions, overtreatment with these same chemicals can create stable emulsions which simply are very difficult to resolve.

Furthermore, not all very small droplets/particles are naturally occurring. Some can be created in normal operations. Pumping is a common cause because, for instance, pumps used to move fluids shear large droplets/particles making them much smaller. These smaller droplets separate much slower, consistent with Stokes' Law.

So far, this paper has shown that older tank sizing paradigms were vastly inaccurate, and that efficiently designed tanks and vessels can sometimes be smaller than their predecessors. Smaller tanks and vessels obviously cost less. And, since they are smaller, they hold less oil. Whatever the current oil price, this saves dollars.
Clearly, a properly designed tank using Stokes' Law and treated with the proper chemicals should produce high-quality effluent oil and water, but just as clearly, when high water cuts are the order of the day, the old gunbarrel/wash tank design is so inefficient that is should probably be considered obsolete. And, if they are, the question becomes, "What takes their place to process today's ultra-high production?"

HIGH WATER CUT DESIGN DEVELOPED AND PATENTED

Finally, a more efficient oil-water separation system was developed, tested, and patented. The patent drawing here shows the first of a series of ever-improving HWSB® Skim Tank designs. This design has been improved and the patents updated several times since this first effort. Each new iteration has improved its performance.



HWSB™ Patent Drawing

This is KBK's "hydrodynamic water separation breakthrough" 21st century replacement for all gunbarrels and wash tanks. It is a game changer. It is simple. It has no moving parts. And it removes over 99.9% of all oil entrained in produced water streams. It costs a little more than a gunbarrel/wash tank, but it recovers enough saleable oil to pay for the difference in a matter of days.

The original HWSB® patent drawing is shown here at the right.

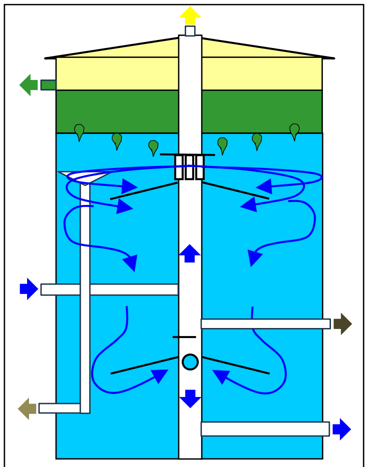
The HWSB® is a uniquely efficient system that accomplishes the goal of removing small amounts of oil from huge volumes of produced water, clarifying produced water to injection/disposal water quality, at last!

Over the next three decades this innovative technology was improved again and again. The HWSB®" rapidly gained popularity. Every new HWSB® was engineered and designed for its unique and individual application to make sure that it performed as expected. Applications grew in number as industry confidence grew, and eventually the HWSB® became a standard of the industry.

The HWSB® clarifies water … better than anything else yet developed. It approaches the ideal condition of piston displacement, resulting in very efficient, repeatable, and forgiving separation efficiencies.

Most importantly, the HWSB® is the 21st century's Gunbarrel replacement … the ideal "skim tank" for separating oil from water.

The HWSB® has no moving parts, so maintenance is zero. It applies to many concepts not found elsewhere in oilfield processing. It employs concepts found outside our industry with methods proven sound in other types of fluid handling.



HWSB™ Skim Tank

Before the HWSB® was introduced, gunbarrels and wash tanks were considered "conventional wisdom" for oil-water separation. But as we have seen above, by 1950 this had become a myth.

Compared to gunbarrels the liquid flow paths inside the HWSB® are vastly improved, as can be seen here. The large baffles near the top slow the water velocity allowing oil droplets to migrate upward. As they slow the water down more and more oil can freely separate. When the water reaches the edge of the upper baffle the water must change direction to flow down between the edge of the baffle and the tank wall. The annulus between the two creates a vortex that draws the water under the baffle, distributing it across the entire cross section of the tank. At this point, the water has slowed to its slowest downward velocity so all separable oil droplets can counterflow upward and into the oil layer above. This uniform and efficient fluid distribution maximizes retention time and assures efficient and near-total oil-water separation.

Interface draw offs are included in all HWSB®s so operators can drain-off offensive emulsions without interrupting normal operations. Each HWSB® includes a center column solids collection and drain system, and a BS&W interface removal system, so when properly operated tank cleaning cycles are prolonged indefinitely.

All gunbarrels had always used parallel pipe water legs to control the oil-water interface level. These could be tilted to adjust the interface inside the tank, but most were woefully undersized, particularly as water cuts increased. Additionally, the cross-over piping between the inlet and outlet legs of these water legs was so small that as water volumes increased the spillovers flooded and the tanks overflowed. Oil was always the first fluid to overflow, creating a costly mess and a dangerous fire hazard.

In contrast, each new HWSB® is supplied with an engineered water leg. The design is new using concentric pipe (pipe inside a pipe) instead of parallel up-down piping. The outer pipe is sized to minimize the pressure drop of water rising in it. The inside pipe is sized to maximize the size of the spillover to accommodate the industry's larger water flows. Each HWSB® water leg is fitted with an external top mounted worm-gear operated jack screw assembly. The jack screw is attached to an o-ring sealed slip sleave fitted to the top of the inside spillover pipe. Operators fine tune the interface level in their HWSB®s using the adjustment wheel on the jack screw. They don't have to shut down the inflow or make any changes to water leg piping. So, by taking an engineered approach the operation of HWSB® Skim Tanks was further improved.

The new HWSB® water leg is hydraulically engineered, tested, and proved that a properly designed concentric water leg could provide the low water leg pressure drop needed to avoid the typically widely varying interface level changes the older gunbarrel/wash tank design. The large spillover weir area of the new water leg allows it to maintain stable and uniform oil-water interface inside each HWSB®, where stable levels are necessary to maximize the continuous recovery of saleable oil.

THE WIDESPEREAD USE OF THE HWSB®

Since the early days of the 20th century KBK's HWSB® has become a standard of the industry. HWSB®s are used in most produced water injection plants, nearly all water disposal plants, and many central tank batteries. While it took years to advance it to today's final form design, the results speak for themselves. Over 4,000 HWSB®s are in service today!

The HWSB® has now proven its value. HWSB®s have replaced untold numbers of gunbarrels and wash tanks. The myth that gunbarrel and wash tanks were efficient has finally been replaced by the reality is that HWSB® is go-to system for 21st century oilfield operations. The myth is dead. Long live the reality!

FINALLY, A FOCUS ON WATER QUALITY

Another reality is the fact that the subject of water quality was ignored in over at least ninety of the industry's 129 years. This started to change as water flooding was introduced in the late 1940s. Waterflooding meant water had to be pumped underground into injection wells completed in the original oil-bearing formations. At first this was easy. But in short order it became obvious that when the produced water contained oil and solids like wax or bacteria, injection wells plugged. New wells had to be drilled, or plugged wells had to be remediated. In either case, the cost was excessive. So finally, the subject of removing oil from water, and the issue of water quality in general, became an important topic to most oil companies.

As the focus on improving water quality increased the "boom years" of the 1970s provided the necessary capital funding needed to develop innovative technologies, systems, and equipment designs that improve water quality. These designs implemented technologies like the HWSB® skim tank, the DFSD® desanding/flow splitting/degassing tank, the use of matrix plate coalescing media, deep bed sand-based filter/coalescers, Lamella plate vane separators, serpentine vane coalescers, vessel desanding using "sand-pan" covered drains, and a wide variety of other tank and vessel internals and processes. While all of these showed promise, when applied in the real world, some proved to be impractical due to prohibitive costs, premature plugging, or other similar issues.

In 1970 after decades of federally funded research the US Congress passed The Clean Water Act of 1970. This triggered the expansion of Federal and State EPA involvement in water handling and disposal issues both the private and commercial sectors. In our industry the focus was on onshore and in offshore water treating operations, where water quality took on new levels of industry focus and costs. An interest persisted until the price of oil declined in 1985.

1985 was the beginning of the "bust years". Oil and gas industry funding levels were reduced and most R&D projects were cancelled. For a time, water quality took a back seat to survival. As oil prices sank to record lows many of the best minds in the oil industry left, seeking work with less volatile industries. Many major oil company R&D departments were closed, and with them a significant portion of the industry's knowledge. This had happened in past boom and bust cycles, and it happened again. One result was that the industry's paradigms remained, and some are still with us today.

Then in the early bust years of the new millennium a new approach to well completions spurred the industry into the "shale oil" boom. By 2010 new methods of oilwell drilling and completion were so successful that they ended the bust and a new "shale oil" boom was born. New horizontally completed wells produced ten to one-hundred times as much oil as vertically completed wells. They also produced huge quantities of produced water and created a whole new set of separation issues.

SMALLER DROPLETS SEPARATE SLOWER

In most oilfield operations there are many circumstances that make separation more difficult. Here's atypical example:

Oil flows from the subterranean reservoir through porous rock at ever-increasing velocities as it approaches and finally enters the well bore. There it A) flows to the surface via its own energy, encountering a choke where large droplets are broken into tiny droplets by the forces of pressure reduction across the choke (just as in the homogenization of milk), or B) is picked up by a plunger or centrifugal pump which exhibits enormous shearing forces in the process of moving fluid through dozens of impellers, or past the ball and seat discharge check valve in a rod pump.

In these and most other cases the result is the same: severe droplet size reduction. Any reduction of the size of the droplet or particle slows down the separation process.

To get a grasp on the sizes we are discussing here, it may help to know that one micron is 1/1,000th of a millimeter, or 1/24,400ths of an inch. While these are very tiny particles or droplets, a person with normal vision can see a 75-micron particle with the naked eye. So, while the 150-micron threshold is tiny, it is not beyond the boundaries of unaided human vision.

NEW TERMINOLOGIES

Before we go further, let's learn a few more unfamiliar terms.

In the world of separation, one or more of the components is suspended in a predominant fluid (liquid or gas) that makes up the largest percentage of the mixture or suspension. This larger, or majority, fluid is called the "**continuous phase**." Additionally, when a mixture is made up of a continuous phase with larger than 150-micron droplets or solid particles, it is considered an unstable mixture or **emulsion**. When the contaminants are smaller than 150 microns, the droplets are described as being in a **colloidal suspension**. The smaller the micron size, the more stable the suspension, until finally the suspension is so stable that no Stokes' Law separation occurs. In this state the surface tension of the micro droplets overwhelms their density difference, and they stay suspended indefinitely in the predominant fluid. We call this an **inverse emulsion.**

Let us focus on the particle (droplet) sizes in more detail. Suspensions of these small droplets are non-stable mixtures of the continuous and non-continuous phases. The degree of stability of the mixture depends mostly on the size of the non-continuous phase, and the viscosity of the continuous phase. Again, when average size of the non-continuous phase particles is larger than 500 microns, and the continuous phase has a viscosity lower than 50 centipoises, separation will generally occur readily, usually within a few minutes or less.

When droplets are larger than 150 minutes, they will usually separate in something between a few minutes and 10-15 minutes. But, when the average non-continuous droplets range from 50 to 150 microns, separation times often increase to times ranging from several hours to several days. It is rare that we store any fluid in an oilfield facility for several days … except in oil tanks!

When the droplets range from 10 to 35 microns, the mixture is considered **colloidal dispersion** where separation may take many days or even weeks.

When the particle size of the dispersed fluid is smaller than 10 microns, it is considered a **stable colloidal suspension**, where separation may not occur in any practical period of time.

And finally, when the particle (droplet) size of the dispersed fluid is smaller than one micron it is a **stable inverse emulsion** wherein no separation occurs.

Homogenized milk is a good example of a stable colloidal suspension. Milk is a mixture of butter fats (organic oils) and water. In the homogenization process, the mixture of raw milk (butterfat and water) is pumped through a tiny orifice under extremely high pressure. This shears the butter fat particles until they are smaller than one micron. The result is a stable, non-separating dispersion of two immiscible fluids (see: https://www.britannica.com/science/homogenization).

This is the kind of suspension often caused by chokes in oil/gas wells, by the shearing action of multistage downhole centrifugal pumps, by cavitating surface transfer pumps, gas lift valves, and by leaking balls and seats in rod pumped wells.

HOW WE MAXIMIZE DROPLET SIZE AND SEPARATION

When we look at the actual conditions typical of most oilfield operations, we find that most oil in water and water in oil will have particle (droplet) sizes above 150 microns when the produced fluid reaches the surface. These are mixtures that normally separate rapidly. Droplets and particles large than 500 microns generally separate in a matter of seconds and are considered non-issues.

However, this is not always the case. When a droplet is sheared from a mixture size of 500 microns to 50 microns, we know that the rapid separation we might have otherwise expected will not occur. If the 500-micron droplet separated in 5 seconds, the 50-micron droplet (now one tenth of the original size) will take a calculated 100 times longer to separate, or 8.3 minutes. This dramatic difference is the reason we should concentrate on the methods of fluid handling in production operations that maximize droplet sizes and minimize or eliminate mixing and shearing.

This helps explain why it is sometimes difficult to separate exceptionally light oil from very heavy produced water. This should be generically easy and fast, but when the light oil droplets are too small, it takes a long time for them to separate!

Again, poor fluid handling techniques can cause droplet/particle shearing, lengthening the times required for separation to occur in our existing facilities. When this happens, producers tend to spend too much money on added or oversized surface facilities. More often than not this is a waste of money.

It is clear that it pays to understand fluid handling.

A few key examples of fluid handling mechanics that cause droplet shearing, longer than expected separation times, and larger (more costly) than necessary surface facilities, are:

The flow of produced fluids through small restrictions, like:

- the ball and seat of a rod pump, through a choke
- the flapper of a check valve
- a pinched flow control valve
- centrifugal sub-surface and surface pumps
- surface gear pumps
- trim sets in liquid level control valves on separators, free water knockouts, heater treaters, etc.

Pumping produced fluids from one vessel to another, as in:

- circulating tank bottoms
- drawing interfaces from gunbarrel tanks
- recirculating interfaces
- recycling sump liquids back to the separation processes

SOME CHEMICALS ALSO REDUCE DROPLET SIZES

In addition to mechanical shearing, most chemical additives used in oilfield operations also have the effect of reducing particle sizes. Examples are:

Emulsion breakers when high instantaneous dosages are applied, such as:

- Slugging a gunbarrel to break a difficult emulsion
- Slugging a heater treater to clean up the oil pad
- Over treating the entire production steam
- Over treating a single well steam

Corrosion Inhibitors: These chemicals often depend on water wetting surface active agents to clean organic deposits from the corrosion sites. These powerful surface-active agents (surfactants) promote very stable oil-water and oil-water-solids emulsions.

SCALE INHIBITORS: Both organic inhibition polymers and inorganic scale inhibitors are formulated to disperse solids, preventing agglomeration. This is the exact opposite from coalescence (droplet or particle size growth). While stable dispersions are not defined as emulsions, the results are much the same since the dispersants prevent coalescence (droplet or particle size growth).

ACIDS: Acids are used for well stimulation. Acids have exceptionally low pH values. A low pH environment promotes dispersion. Therefore, droplet and particle coalescence will not normally occur in low pH environments. Acids applied in oilfield production operations nearly always contain surface-active chemicals used to remove the oily deposits from the reservoir rock and scale the acids are designed to attack. These surfactants promote chemically stable emulsions, and this problem is enhanced further by the presence of the exceedingly small (usually less than one micron) solids particles carried back to surface treating facilities by spent acids.

FRAC POLYMERS/GELS: Like scale inhibition polymers, frac fluid polymers create very difficult and stable inverse emulsions. These are often so stable that they can only be broken by breaking down the polymer chains. This is both costly and labor intensive, since all frac companies continuously alter their frac polymer chemistry. This situation is compounded by the huge initial amounts of polymer containing flowback water the producer must scale up to treat.

Chemically stabilized emulsions add time to the physical separation, as has been described in the preceding explanation of Stokes' Law. This report can shed light on the causes, but only real-world experience can help predict increased separation time.

OIL-WATER SEPARATION AND RETENTION TIME

It can be said that effective physical separation is a function of efficient fluid distribution and time. The required separation time is often referred to as "retention time," or the amount of time a fluid is allowed to reside in a process vessel before the desired separation takes place.
A key factor contributing to oil-water separation in facility design is the prediction and determination of real retention time.

From the above it is obvious that droplet or particle size is the most critical factor when attempting to predict what retention time may be needed, since it is the only exponential function in Stokes' Law. It is also obvious that the required retention time must be provided or separation will not occur.

If the flow through surface facilities short-circuits, separation will not adequately occur regardless of size. If the surface facilities are too small, separation will not occur since sufficient time will not be available, even if distribution is excellent. If facilities are properly sized but the attention to distribution is lacking, separation efficiency will suffer. And, if the facilities are too large, money is wasted.

Too much money has been wasted on poorly designed, improperly sized surface facilities throughout the history of the oil industry, particularly since waterflooding was initiated, and even more so now with the development of horizontal drilling and multi-stage fracking. Most gunbarrel tanks mal-perform in today's high water cut conditions. FWKOs struggle because they lack the proper internals. Undersized heater treaters fail to dehydrate crude oil or control its RVP.

Unfortunately, this trend has not slowed. In fact, in all "boom" times just the reverse is true. This happens because our industry is limited in human resources, so it focuses on the larger issues, letting issues like this go unattended. This also has happened because of the widespread lack of information, and a general lack of knowledge. The most common oilfield approach to purchasing surface facilities has been to simply oversize everything; to throw money at the problem.

And, in hard (bust) times, there is no money and too few experienced operations personnel who know better!

And regardless of the boom or bust timing, when an operator is faced with the prospect of a new prolific oil well, shut in and waiting for surface process facilities, efficiency takes a back seat to availability every time!

But the worst condition we face is that most surface facility designers and fabricators simply copy what was done the last time, particularly if it seemed to work … even if "the last time" was three decades ago! This perpetuates the mistakes of the past.
So, it is important that we understand that it is possible to find the right balance between separation needs, retention time, surface facilities design, price, and delivery. Remember, the equipment you buy today is likely to be there 30 years from now … so making the best decision has far reaching consequences!!

With this basic knowledge of separation, it should be possible to leverage the available technologies and good operating practices to optimize surface equipment and facility designs. These will save money up-front and during the entire life of each lease or field.

RETENTION TIME – THE FACTS AND THE FICTION

It is a common belief that if we produce 2000 barrels a day, and we believe we need one-half a day's worth (12hours) of retention time to accomplish the desired separation, we set a 1,000-barrel capacity process facility. This appears to make sense, but does it?

Well, for years hundreds of retention time studies have been performed across the industry. Some use chemical tracers. Others use CFD modelling. Regardless, each confirms that the fact that the actual retention time of most facilities is only a small fraction of the original expectation, or design goal.

We can define the optimum design as having 100% "hydraulic efficiency". That is, the fluid entering a facility designed for 12 hours of retention time leaves 12 hours after it enters.

The design goal of 100% hydraulic efficiency is rarely approached. When 100% hydraulic efficiency is achieved, flow velocities are so fast that mixing occurs, and instead of achieving any separation the result is droplet shearing and a homogeneous mix. The fact is that hydraulic efficiency that is too high, or too "good," can create in inseparable mixture rather than one that separates rapidly!

Hundreds of actual field tests prove that actual retention time in existing process facilities, even those with the most well-known, best liked designs, are in the 0.1-21% range of the ideal design goal of 100% hydraulic efficiency.

The fact that the difference between the design and the actual hydraulic efficiency is so great is both enlightening and discouraging. An efficiency range of 1-21% should be totally unacceptable, no matter what the subject.

A better system is clearly needed and warranted!

To increase the hydraulic efficiency in oil-water separation process vessels the designers always include "special" flow distribution systems. These include baffles, velocity increasing orifices, torturous matrices, vortex creating devices, parallel plates, random mass-transfer materials, coalescing tubes, and woven synthetic cloth barriers, just to mention a few.

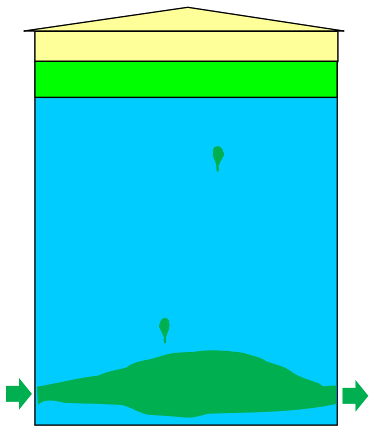
These and many others have a positive effect on retention time and hydraulic efficiency. Most increase the actual retention time by a factor of two to three times, often increasing retention time to from 1% to 3%, 3% to 6%, or even 6% to 21%. In proper combination they can increase separation efficiency ten-fold or more!

However, some attempts have had negative effects on separation, too! If a design accelerates the fluid flow in a vessel so it is flowing faster than the Stokes' Law rise/fall rate of the separating droplets, mixing occurs.

It helps to remember that mixing is the opposite of separation! When this happens, the fluids are not sufficiently exposed to the necessary dynamic flow conditions for separation to occur, even though the retention time and hydraulic efficiency may be theoretically or realistically improved.

From this you can see that there is more to enhancing separation than simply increasing retention time. So, let us consider a sample water clarifier process vessel.

When the flowing velocity of a fluid exceeds separation velocity of immiscible droplets in it, velocity trumps separation and the immiscible droplets fail to separate. While separable under slower conditions, these oil droplets leave the tank with the water. This happens in most gunbarrels/wash tanks in high water cut service.



Poorly Designed "Skim Tank"

The point to be made here is that separation is dependent on both 1) retention time, and 2) slower fluid flows. Unless both are correct, separation suffers or fails completely.

AN EXAMPLE CASE

To bring all of this into focus, let us look at an example case.

Assume the example gunbarrel is a standard 1500 barrel of the conventional design shown in Figure 1 (Pg. 4). This gunbarrel contains 1/3rd water and 2/3rds oil. Oil production is now twenty barrels per day. Therefore, the 20 B/D oil flows through 1,000 barrels of stored oil in the gunbarrel. By dividing the oil capacity of the 1,000-barrel gunbarrel by the 20 B/D production, it is easy to see that the ideal oil retention time is 50 hours.

In this example the ideal crude oil retention time is 50 hours based on the "tank volume versus flow per day" formula. To determine the actual retention time an oil soluble dye tracer was applied in the field. The results showed a peak concentration after 1-1/2 hours, and zero concentration of the tracer after three hours. Therefore, the 3-hour actual time divided by the 50 hour calculated time results in only 6% hydraulic efficiency. If the oil does not separate and dehydrate in three hours' time, a larger, different, or better design tank must be found.

THE FOCUS SHIFTS TO WATER QUALITY

With the advent of large scale waterfloods in the late 1940s, water quality grew in importance. By 1960 water quality was in the forefront of the minds of all who dealt with water injectivity as an enhanced oil recovery mechanism, or simply for underground disposal... By 1970 the first Clean Water Act became law in the USA. Just as this Act mandated cleaner water, it also became a model for cleaner water for countries globally.

From the 1970s through the mid-1980s a great deal of thought went into improving water quality. Large investments were made too in efforts to improve the inefficiencies of older skim tanks. Most were originally simply empty tanks with no internals to aid in distribution or collection of inlet and outlet fluids. These often looked like the one in Figure 4.

Field tracer surveys proved that short-circuit flow paths do exist in most older skim tanks, regardless of design.

Retention times were documented at less than 6% of the calculated (expected) retention time, in test after test. Many new concepts were tried in an effort to improve water quality and lower costs. Additionally, internal baffle adaptations were also tried in attempts to improve effluent water quality.

In this brief period the industry's financial condition was unusually strong. The value of crude was high enough that every effort was made to capture every drop and send it to the pipeline/refinery. Therefore, more testing of higher degrees of sophistication were funded.

New tank internals were developed, installed, and performance tested. Practical, proven test methods were used. These include the application of known quantities of Fluorescein or Urinine chemical dyes. But in general, the results were quite dismal.

More and more test results proved that most of these contemporary designs still had low hydraulic efficiency, and in many cases even poorer separation. Adding baffles simply caused more mixing, and more re-entrainment rather than achieving the expected increases in separation efficiency.

RETENTION TIME VS. SEPARATION

During the boom years from 1973 to 1985, even more exotic designs were tried, and reached as high as 21% hydraulic efficiency. But they proved to be too costly or too unreliable. Furthermore, the poorest of the new designs were proven to have hydraulic efficiencies of less than 0.1%.

However, in all of this, important new lessons were learned. One of the more important lessons was that **increased retention time alone does not necessarily enhance the separation of immiscible fluids**.

The reason for this is that most of the various methods of increasing retention time, such as vertical baffles forcing a serpentine flow pattern through a skim tank, increase the horizontal flowing velocity of the fluid to a rate greater than the separation velocity of the separable fluid fraction. Obviously, when the horizontal flow rate is greater than the vertical separation flow rate, separation ceases and mixing occurs.

The industry began to come to grips with the fact that good flow characteristics enhance separation as much as increased separation time. Another point learned was that eliminating acceleration points, where re-entrainment of separated fluids can occur, was even more important than vessel size. An example of this is a vertical baffle or group of vertical baffles with holes drilled in it/them. The holes distribute the flow across the cross section of the baffle and prevent short circuiting by creating a small pressure drop. However, the result of this or any restriction is to create an accelerated velocity. The fluid flow rate must increase through each hole. As was explained above, when the horizontal flow rate is greater than the vertical separation rate, separation ceases and mixing occurs.

Furthermore, flow path studies have proven repeatedly that altering flow direction can cause mixing and re-entrainment of separable fluids. As the flow of a fluid exits any office, the pressure drop produces eddies that flow back toward the orifice, increasing the flow velocity even more, shearing larger droplets into smaller droplets and mixing them back into the exiting fluid stream. Obviously, these forces are the opposite of separation.

THE NEWEST COLD WEATHER HWSB® DESIGN

As the shale oil boom of 2010 to 2015 expanded into cold weather areas it was clear that the industry needed to develop production equipment designed for the harsh conditions of colder climate areas. In response, a new HWSB® design evolved. It was designed with a unique externally adjustable internal water leg, tested, proved, and patented a new "Cold Weather" HWSB® with the emphasis on freeze protection in cold climate areas. This proved to be a valuable design for the rapidly expanding Bakken Field in North Dakota, fields in Wyoming and the developing DJ Basin in Colorado, and for all other very cold weather producing areas where wintertime operations demand a focus on freeze protection.

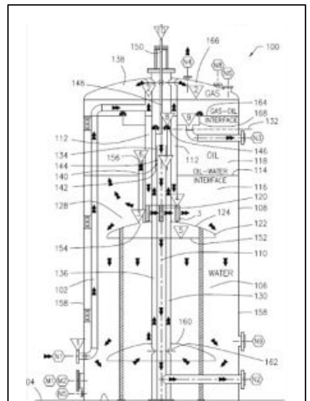
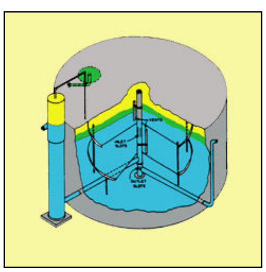


FIG. 1

This innovative Cold Weather HWSB® design was successfully tested in the winter of 2010-2011. Its performance exceeded all the producer's expectations. A patent application was prepared and filed in April 2012, and the patent was granted on July 30, 2013.

OVER 4000 HWSB® AND DFSD® TANKS IN SERVICE TODAY



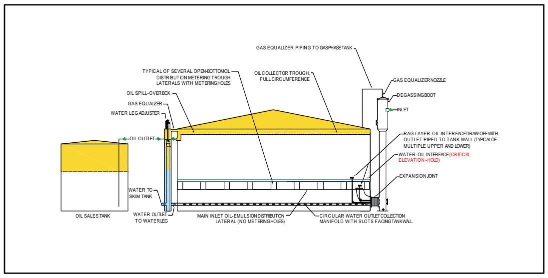
Today, well over four thousand HWSB® Skim Tanks and DFSD® desanding/degassing/flow splitting tanks are in service in the domestic oilfields of the United States alone. Many more are working to clarify oil and water in Canada, Mexico, India, South America, the Middle East, and elsewhere around the world. Each one is setting the pace as the 21st century water-oil separation system "standard of the industry", replacing gunbarrel and wash tanks everywhere.

Since most oilfield process conditions vary from lease to lease and field to field, KBK's engineers design each HWSB® for its specific application. And to date, every HWSB® and DFSD® has outperformed the best expectations of its owner.

A 21ST CENTURY REPLACEMENT FOR GUNBARRELS/WASH TANKS

While water quality is critical to most oilfield operations, oil pays the bills. And, whether applications are faced with high water cuts or not, crude oil still needs to be dehydrated to pipeline specifications, typically 99.5% pure (<0.5% BS&W).

Most oilfield operations applications must and do dehydrate oil with small concentrations of water, sometimes processed in atmospheric vessels; often gunbarrels. For these applications, the "High Efficiency Gunbarrel," or HEGB™ does the job.



The HEGB™ design focuses on crude oil dehydration. Production with up to 50% water is the target process stream. The HEGB™ achieves <0.5% BS&W!

The HEGB™ uses a unique hydraulically under-balanced distribution system designed to meter inlet fluid across the entire cross section of the tank, maximizing dehydration through a uniform distribution of reduced velocity upward oil flow into and through the oil-water interface as seen here. The distributors allow the heavier water to flow downward to below the oil layer where it can be collected and withdrawn. Oil rises to near the top of the HEGB™ where it is collected throughout 360° of the tank, achieving uniform collection of dehydrated crude oil to maximize efficiency. The HEGB™ design has been proven to be more efficient than conventional gunbarrels in applications worldwide, ranging from 2 BOPD to more than 250,000 BOPD.

CONCLUSIONS

Separation is widely misunderstood. Myths developed in past generations often create frustration and confusion in current operations. However, when separation issues are addressed within a full knowledge of its realities, success is assured.

ABOUT THE AUTHORS

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