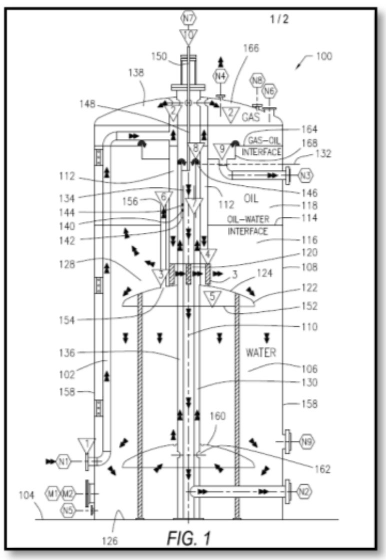
Separation in Oilfield Operations

"Gunbarrels: Myths versus Realities"

A Technical Paper

Prepared for

All Interested Oilfield Personnel



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Another White Paper

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PREFACE

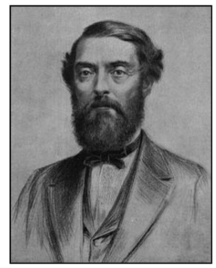
These days knowledge is everything! With oil prices dipping into the $30/barrel the more we know the more likely we are to prosper. At these oil prices it is not surprising that the oil industry has a keen interest in producing and selling every drop of its precious oil. And yet, even so, there is a huge knowledge gap in the industry. Current methods of "how to" process to recover every drop of today's crude oil is too often defeated by the lack of knowledge and by the paradigms of the past. Newer concepts are often overlooked in favor of older methods, "Because we've always done it that way!" Maybe, it's finally time to try something new and different.

This paper attempts to improve the readers understanding of how to capture every drop of oil in todays' operations. It attacks some of the paradigms and myths of the past that tend to perpetuate the "We've always done it that way!" issues we all encounter.

This paper prompts us to recognize the differences in today's oilfield operations, to embrace our evolving technologies, and to be willing to "think out of the box." It attempts to enhance each reader's knowledge so we can collectively meet our goals of maximized oil recovery, better facilities performance, and higher profitability.

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, oil pioneer Edwin Drake completed the world's first oil well. He chose an old bathtub to separate his precious oil, dumping the produced water down the creek. My, how things have changed!



But as much as things change, they stay the same. Crude oil producers today still separate water from oil. The methods have changed since 1858, of course, but the need to separate impurities remains the same. Refiners set the price for crude oil based on its level of purity. By removing impurities, oil producers avoid price penalties from crude oil buyers and maximize profits.

Over the decades since Drake's first well the oil industry has experienced an unprecedented rise in water production levels. Many oil wells now produce far more water than oil. Producing and separating conditions have changed *dramatically. Where in 1858 the emphasis was on separating small amounts of water from Drake's precious oil, today we often focus on separating small amounts of our precious oil from very large amounts of produced water.*

Some may believe that "separating is separating". However, in reality, 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!

Once this reality is understood, it may become apparent, even obvious, that the process facilities used to accomplish the separation of water from oil may not be suitable for the separation of oil from water. This is a key concept, and the first of several paradigms to be challenged in this paper.

AN INDUSTRY IN TRANSITION

As the world's thirst for crude oil grew, Drake's efforts were eclipsed, and then eclipsed again! Drake's first well produced 25 barrels of oil each day. By 1872, producers mimicking Drake's methods were producing 16,000 barrels of oil daily from Drake's Oil Creek area in Pennsylvania. Eighty nine years later, in 1961, US oil production peaked at 9.6 million barrels per day.

From 1961 until recently the US oil industry was in decline. Then, with a powerful resurgence, recent developments in the Baaken, Eagle Ford, and other prolific oil US reservoirs, the industry began to forge ahead again. Thanks to 21st century drilling and completion technologies, in 2012 the domestic industry enjoyed its most rapids growth in history! The come-back is now in full swing!

TRANSITION MEANS CHANGE

During the first eighty-nine years of oil industry evolution we focused on removing small amounts of water from large amounts of produced oil. Then, a new technology changed that focus. Secondary recovery (aka water flooding) allowed producers to re-enter older fields and recover unprecedented quantities of oil from known formations using water to drive the oil through the old, energy depleted reservoirs into producing wells. It was a panacea! However, with increased oil production came increased water production.

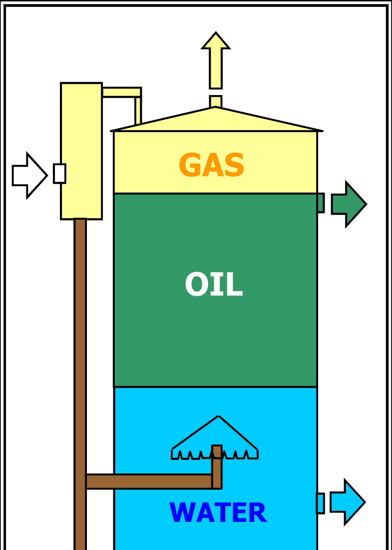
Almost overnight, water oil ratios climbed in the 90+ percent range in many waterfloods. This created many new challenges. Process systems and equipment used to separate small amounts of water from oil suddenly were incapable of separating the huge amounts of water being encountered. The process focus was shifting to system and vessel designs aimed at addressing his issue for the first time ever.

Contrasting this need for change was the paradigm that the systems and processes used in the past had always worked, and since those oil focused processes had always worked, they should still work. The "we've always *done it that way" paradigm dominated, and needed changes were slow to come because of it.*

THE "BOOM" AND BUST CYCLE ... AGAIN

By 1973 the industry had shifted to an international focus. Major oil companies had discovered huge oil plays in the Middle East. Revenue flowed into these nations as never before, and they began to ban together in an effort to control the price of crude oil on a world-wide basis. This group of countries formed the Organization of Petroleum Exporting Countries, or "OPEC". In 1973, OPEC raised the price of exported oil by 70%, and embargoed the export of their oil to the US in retaliation for US involvement in the Gulf war, cutting off all Arab nation oil imports into the US. Financial markets in the US suffered, but the oil industry entered a twelve year "boom" as we heightened efforts to produce more domestic crude oil to offset the embargo. Domestic crude prices rose from $3.45/barrel to over $45/barrel during these years.

Waterflooding reached it pinnacle. It was augmented with chemicals like surfactants and CO_2 *which further enhanced oil recovery. And, as you might expect, produced water volumes reached unprecedented levels.*



TYPICAL GUNBARREL/WASH TANK
FIGURE 1

As an industry, the need to separate contaminants from produced water rose to prominence. We needed to minimize disposal or injection well plugging to sustain oil production under these conditions. These separation needs were accomplished using many different types of equipment and in many different methods. Some of these were more efficient than others, but just as real advancements were about to be introduced, the embargo ended and by 1985 the price of crude fell back to near-re-boom levels. The industry fell into a long recessionary period we call "the bust", and many advancements were lost or forgotten.

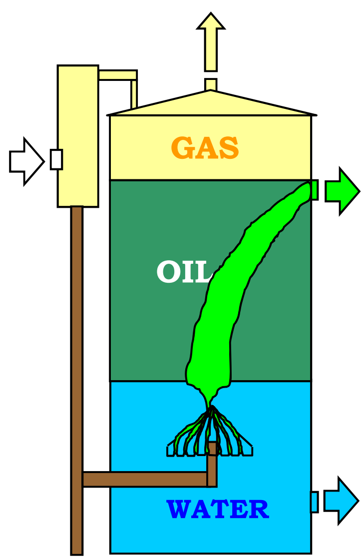
This paper aims to bring them back to life.

SEPARATION FUNDAMENTALS

In any separation system, the first needs are to select the proper system and the correct size. Before deciding on the proper size and design, it is useful to know what the more common and widely accepted designs are and how evolved, since these may embody the paradigms we need to overcome today.

Since about 1870 the most basic separation system is the "Gunbarrel", or "wash tank". It is an atmospheric vessel, (tank) used to separate crude oil from *produced water. This system is designed to remove contaminants known as basic sediment and water, or "BS&W", from produced crude oil. The emphasis of design for the Gunbarrel or Wash Tank is on effluent oil quality, with no concern whatsoever for water quality. This is the industry's first crude oil dehydrator.*

In this system produced oil, water, gas and any solids first flows into a degassing chamber referred to as the "gas boot" located on top or beside the tank. Gas flows up and is equalized with the gas phase in the tank through an equalizer pipe. It mixes with gas evolving from the crude inside the tank and is piped off to atmosphere, a flare, a vapor recovery system, or off-site to sales.



CRUDE FLOW PATH
FIGURE 2

Gas free liquids flow down and out of the gas boot into a "downcomer" pipe which extends to near the bottom of the tank where the inlet oil with its BS&W exit under a baffle, or "spreader". The lower 1/3 of the tank was to be full of water, so the BS&W could be absorbed into it, allowing the oil to rise. With 2/3rds of the tank filled with oil, any remnant water was thought to have sufficient time to separate completely. When this was not the case, larger tanks were chosen until it functioned as desired.

Early spreaders were designed with serrated bottom edges in the hopes of better oil distribution. These were inverted "V" shaped notches, like saw teeth. The v-notches were intended to "meter" or distribute the flow of oil uniformly through the water phase. The design philosophy was that "washing" the crude oil through water would allow the water to flow out of the crude oil. Thus the name "Wash Tank".

WHY "GUNBARREL"?

Some designers placed the gas boot on outside the tank (see Figure 1, Pg. 4 and Figure 2, this page). Others placed the gas boot, or more accurately, the degassing boot, on top of the tank with the downcomer inside (Figure 3, Pg. 7). In both cases, when viewed from the top, the tank and gas boot form circular images, one next to the other, which are similar to the circles one sees looking down the barrel of a shotgun, as seen here. As guns were a part of everyday life in the late 1800s, this was the basis for the term "Gunbarrel" tank, also sometimes called a "Shotgun" tank for the same reason.

It is believed that the Gunbarrel concept was first used in the 1870s. In the *years that followed, trial and error applications saw its size increase until it finally performed as desired and took the shapes and sizes familiar to us today. This helped form the oilfield design paradigm that "bigger is better". For better or worse, this simple design remained unchallenged for over ninety. It was, and still is, a standard of the industry for atmospheric crude oil dehydration. But, as we will soon see, it is not very efficient!*

RETENTION TIME VS. SEPARATION

The "Gunbarrel" design was finally challenged in the 1970s, when the uncommonly high price of crude oil just after the Arab oil embargo justified field and laboratory research into the relative efficiency of this and other "standard" oilfield equipment designs. The results were startling, and disappointing to say the least!

Retention time studies were conducted in separators, Gunbarrels, Wash Tanks, free water knockouts (FWKOs), Heater Treaters, and even storage and skim tanks. The results showed that the hydraulic efficiency of all designs were extremely low, most ranging from 1% to 3%, with a few ranging to from 3% to 20%. Bigger had been thought to be better, but these studies refuted this concept. In most cases, too big was proven to be as bad as or worse than too small!

These studies also identified the flow characteristics which promoted low hydraulic and separation efficiencies, and helped explain some of the reasons for the gross inefficiency findings.

These studies also proved that all fluids predictably take the path of least resistance. Not surprisingly fluids traverse vessels in a short, narrow flow path between the vessel inlet and outlet. This was something of a revelation since it had been presumed that fluids naturally distributed uniformly in these vessels, and flowed like a plug or piston through the entire cross section.

In addition, these studies proved that the both the flow path and the fluid velocity in it determine the degree of separation, and that they are almost never constant in the real world of ever-changing oilfield operations where flow conditions are rarely constant. The only constant was the fact that that when the velocity of the predominant fluid exceeded the separation velocity of any fluid or solid in it, that velocity precludes most separation.

This was another revelation. It confused many of those involved in these studies since it refuted the age-old supposition that our industry-wide separation systems and vessels functioned efficiently!

As the hydraulic efficiency of more and more equipment was tested the results were equally disappointing. This held true for most traditional oilfield separation equipment, and was particularly true for the Gunbarrel, *where results were both disappointing and surprising.*

GUNBARREL SIZING

In the past, Gunbarrel sizing had been based on the supposition that oil needs eight to 24 hours of piston displacement retention time to dehydrate, depending on API gravity. Decades of observation had determined that these retention times could be related to the gravity of crude, from 20° API to 40°API. It was known that in heavier oil applications, all bets were off, as much more time was needed. This had meant larger and larger Gunbarrel tanks.

Those same studies showed that the metering concept of the serrated (saw-tooth) distributor baffles in the bottom of Gunbarrel tanks was also invalid. In fact, it was found that crude oil entering a Gunbarrel (and most other vessels) oil wets ALL of the surfaces, including the serrated spreaders. Once oil wet, rather than being metered out into the water phase by the serrations, the crude was found to really flow in rivulets attached to the serrated spreader structure, up the outside of the spreader and up to the outside of the downcomer pipe, up the pipe through the oil layer to its top where it finally disengaged from the pipe wall and flowed across the top of the oil layer to the oil outlet. In high oil flow conditions some of the oil did disengage from the spreader edge in large droplets or globules. These oil droplets then flowed rapidly and vertically through the water layer and into the oil phase. From there very little, if any, horizontal distribution occurred, and the oil flowed vertically to the top of the oil layer and then diagonally to the outlet nozzle, circumventing the bulk of the tank's volume. It was found that only a very small portion of the oil stored in the tank actually came in contact with the inlet crude oil and emulsion. In many cases the inlet crude was found to actually only reside in the oil phase for minutes. This finding refuted the old design philosophy of sizing based the 8-24 hours of crude oil retention time paradigm

Furthermore, in many test results, the emulsion content of the inlet crude actually increased when the crude was "washed" through the water layer under the oil.

A NEW SEPARATION PARADIGM

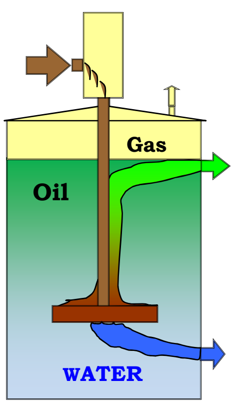
It became clear that any water in the oil phase had to separate in a matter of minutes, rather than in a matter of hours. And, since the age-old belief that 8-24 hours of oil retention time was proven incorrect, it became obvious that Gunbarrels had to have been vastly oversized, and that they all have extremely low hydraulic efficiency because of the design. It became crystal clear that for vessels to be hydraulically efficient, maximizing retention time, two conditions had to be met:

1. *Uniform inlet fluid distribution, and*
2. *Uniform effluent fluid collection.*

At this point, design emphasis began to shift. Some designers began to look for new methods of increasing the actual distribution of oil within a smaller vertical column (volume) of stored crude to improve dehydration. 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, scale clear plastic models were constructed so various internals could be observed and tested. In general terms, the results were quite encouraging.

And not surprisingly, each investigator was amazed at how inefficient the old original Gunbarrel design actually. Figure 3 (RIGHT) is an example of the actual typical flow path the oil and water take in the conventional Gunbarrel.



ORIGINAL
GUNBARREL DESIGN
Figure 3

It also became clear that when inlet fluid distribution is more uniform the results were dramatic increases in actual crude retention time and separation efficiencies. As these studies progressed it was eventually discovered that truly uniform distribution of incoming crude and emulsion through the entire cross section of the oil layer increased retention by factors of from 10 to 35 times!

Furthermore, and equally surprising, it was also found that process capacity and separation efficiency increased even more when the inlet crude and emulsion is NOT washed through the water phase, but is introduced into the emulsion rich layer just above the water phase. These studies proved that both naturally occurring and artificially added emulsion breaking (aka demulsifier) chemicals tend to concentrate in this 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 as we'll see later when we take a close look at separation physics through Stoke's law.

Finally, it was observed that flow velocities needed to be carefully considered. A velocity relationship was observed wherein a fractional oil flow rate directly proportional to API gravity accomplished the desired gravity separation of water from oil. This brought a whole new engineering dimension to the concept of "proper" design.

The conclusion of this work proved that old sizing paradigms were vastly incorrect, and that properly designed Gunbarrels can be much smaller than originally thought. This reduces the capital cost of Gunbarrels. And, since these new Gunbarrels are smaller, the investment of "oil-in-inventory" in smaller Gunbarrels is also obviously reduced. At $100/barrel, this *can add tens of thousands of dollars to cash flow to the owner.*

Further, a properly designed Gunbarrel could produce a very high quality oil effluent regardless of summer-winter swings in temperature and viscosity, for most oils in the 27° API and above range.

WHAT ABOUT WATER QUALITY?

The subject of water quality had been ignored in the early decades of the industry. This began to change with the advent of water flooding in the late 1940s. When produced water contained so much remnant oil it was found to be plugging injection and disposal wells, and as the price of crude rose from its government regulated pre-war $1.25/barrel level to an unregulated and much higher value, the issue of removing oil from water, and the issue of water quality in general, finally reached a level of significance and importance to many oil producers, and some focus shifted to water quality.

In the "boom years" of the 1970s, new systems were developed and introduced which improve water quality. These designs implemented matrix plate coalescing media, deep bed sand-based coalescence, Lamella plate separators, serpentine vane coalescing, and a wide variety of other internals and processes. All of these showed promise, but when applied in the real world, some proved to be impractical due to high capital costs, premature plugging, and other related issues.

Bolstered by with the Clean Water Act of 1970, and the expansion of Federal and State EPA involvement in water handling and disposal issues both onshore and in offshore operations, water quality took on a brand new level of industry significance and importance.

Then, in 1985, came the post-boom "bust years". During the next 20+ years the concept of survival in a depressed industry outranked the need for research. As oil prices sunk to record lows many of the best minds in the oil industry left, seeking work in other, less volatile industries. Nearly all major oil company R&D departments were closed. And with them departed a good deal of the industry's knowledge, never to return.

Today, however, with the knowledge that water separated in any Gunbarrel tanks tends to take the path of least resistance to the water outlet, we can and do focus again on water quality. The water distribution and collection in conventional Gunbarrels is poor at best, resulting in high fluid flow velocities that preclude oil separation. Therefore, the quality of effluent water in most Gunbarrels is often extremely poor. It typically ranges from 1500 ppmv to 5000 ppmv oil in the effluent water, or more. When water quality was a non-issue, no one cared. Now, with oil at $100 per barrel, 1500 ppmv of oil in 3000 barrels/day of water represents oil worth $181,050/year in lost oil revenue! Clearly, water quality needs to be a key focus today.

Remembering that the Gunbarrel was developed to remove small amounts of water from large amounts of oil, we can now recognize that the Gunbarrel no longer fits our high water cut applications. It was clearly the time to develop a system that is designed for todays needs.

FIRST SKIM TANK PATENTED

In response to this need HTC resolved to preserve the effort to continue research and to develop better, more efficient systems. In 1993 these efforts resulted in the first of a series of patents finally advancing the design engineering of Skim Tanks, Gunbarrels/Wash Tanks, De-sanders, Flow Splitters, Three Phase Separation, and many others, all highly efficient by comparison to those of the past. These designs were honed throughout the next several years to become performance standards in the new millennium … evolving finally into a family of patented, proven, highly efficient, and widely accepted 21st century separation technologies from HTC.

In order to better understand the subject of separation, it is necessary to get a grasp of separation principals. This starts with an understanding of Stoke's Law. What follows is a start in that direction.

SEPARATION BASICS - STOKES' LAW

The static separation of immiscible fluids (fluids that are not soluble in one another), and/or suspended solids, can be predicted by applying Stokes' Law of physical separation. Predicting static separation is very straight forward. An example is predicting the separation of gravel dumped into a tank of water. The tank is "static", which means there is no motion inside. By applying 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 this simple principle is a good beginning to understanding "gravity separation" and Stokes' Law.

However, the word "static" is the key to distinguishing the merits of Stokes' Law from the dynamic separation typically demanded in oilfield separation systems where fluid stays in motion all the time.

Most oilfield process separation systems are not static. There is constant if irregular motion inside process vessels. Nothing is static! So, a law that predicts the rate of static separation had to be modified for oilfield operations where almost nothing is static. Fluids are constantly flowing all the time. Because of this, Stokes' Law does not go far enough by itself to be applied to most *process separation challenges in our industry.*

Let's review. A typical oilfield process separation system can be accurately described as those with continuously flowing conditions where all fluids are in motion. But, Stokes' Law only predicts separation in a static, non-moving environment. Nevertheless, a good understanding of the concepts set forth in Stokes' Law is considered critical to the understanding of separation. So, we start with it.

STOKES' LAW

Stokes Law was published in 1851. It represents the velocity of a rising or falling fluid or particle under static conditions with the following formula:

Where:

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

F = 6πrηv,

… and where

F is the frictional force
r is the particle radius
η is the fluid viscosity, and
v is the particles speed
V_s is the particles settling velocity,
g is the acceleration of gravity,
ρ_p is the density of the particles, and
ρ_f is the density of the 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.

In order to relate Stokes' Law to the dynamic separation problems encountered in typical oilfield separation it needed to be modified. A good deal of work was necessary to accomplish this. The modified Stokes' Law can be represented in formula form as follows:

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

The Stokes' Law formula focuses on two immiscible phases at one time. When more than two are present, each is calculated independent of the others.

Modified Stokes' Law states that the velocity (V) of separation 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), divided by the viscosity (N) of the continuous phase.

PARTICLE SIZE IS KEY

In both versions, all of the variables have a decided impact on separation. However, the greatest impact is the size of the particles to be separated, since the relationship is not linear (one-to-one), but instead is exponential (the square) of the droplet or particle size. That is, as the particle size doubles, the separation velocity is increased by four times. As size triples, the separation velocity is nine times as fast. As size quadruples, the particle separates *sixteen times as fast, and so on. The inverse it also true. A reduction in size of 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.*

It is very important to grasp this concept in the real world, since many of the ways we handle and treat produced fluids may reduce or enlarge the size of the particles and droplets we are eventually going to try to separate.

Separation in the oil patch involves the separation of oil, gas, water, and solids from one another. Separating oil from water is necessary to achieve the oil quality necessary so the oil can be sold and shipped to refineries without BS&W penalties. Separating oil and other contaminants from water is necessary so the water can be re-injected or disposed of without the plugging effects of entrained oils and solids on injection or disposal wells. Furthermore, crude oil has a significant commercial value today justifying its recovery in most cases. Furthermore, any oil left in the water not only causes injection or disposal well plugging, but also obviously reduces the income stream from the potential sale of the oil lost to the water phase.

So clearly, larger particles sizes are preferable. One of the ways we grow or reduce the size of the droplets or solids we are going to try to separate is with the addition of oilfield chemicals. In most non-chemically stabilized mixtures of oil in water, the majority of the droplets of one in the other are larger than 150 microns. These droplets separate rapidly simply because of their size. However, when the droplets or particles are smaller than 150 microns, separating them becomes a real challenge. Over treatment with oilfield chemicals is a major culprit reducing sizes, and thereby in causing chemically stable emulsions and poor separation.

Many other circumstances also cause smaller droplets. Pumping is another real world culprit. For instance, when mixtures with large droplets are moved from one place to another, the act of moving them may provide the necessary physical force necessary to divide the large droplets into smaller and smaller droplets. Imagine the impeller of a typical centrifugal pump, turning at 3550 RPM through a mixture of produced water and oil. The rapidly turning impeller shears larger droplets into smaller and smaller droplets as it turns, pumping the mixture down the line. The smaller droplets separate slower, consistent with Stokes' Law.

HOW DROPLETS GET SMALLER

In most oilfield operations there are many circumstances that make separation more difficult than it could be because oil droplets are sheared, or reduced in size. For instance, oil flows from the subterranean reservoir at an ever-increasing velocity into 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 (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 these and most other cases the result is the same droplet size reduction. Any reduction of the size of the droplet or particle slows down the separation process. When the droplets/particles are smaller than 150 microns in the real world, the mixture is redefined as a suspension, and separation occurs at a snail's pace.

To get a grasp on the sizes we are discussing here, it may help to know that one micron is 1/1000th 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, we need to understand a few more terms.

*In the world of liquid or gas separation models, one or more contaminants are usually suspended in a 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 considered to be 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's focus on the particle (droplet) sizes in more detail. Suspensions of these small droplets are generally non-stable mixtures of the continuous and non-continuous phases. The degree of stability of the mixture depends predominately 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 centipoise, separation will generally occur readily, usually within a few minutes or less.

When droplets are larger than 150 minutes they will separate within several minutes or up to an hour or so.

When the average non-continuous droplets range from 50 to 150 microns, separation times often increase from several hours to several days.

When the droplets range from 10 to 50 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 ***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 considered to be a ***stable colloidal suspension*** *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 very high pressure. This shears the butter fat particles until they are smaller than 1 micron. The result is a stable, non-separating dispersion of two immiscible fluids (please see: http://www.foodsci.uoguelph.ca/dairyedu/homogenization.html for more information).

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, and by leaking balls and seats in rod pumped wells.

HOW WE EFFECT 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.

However, this is not always the case. When a droplet is sheared from a mixture size of 200 microns to 50 microns, we know that the rapid separation we might have otherwise expected will not occur. If the 200-micron droplet separated in 5 minutes, the 50-micron droplet (now one fourth of the original size) will take a calculated sixteen times longer, or 625 minutes (the square of the square of the original separation time, according to Stokes' Law). This dramatic difference is the reason we should concentrate on the methods of fluid handling in production operations. This also helps explain why it is sometimes difficult to separate very light oil from very heavy produced water, which should be easy to accomplish.

Again, poor fluid handling techniques can cause droplet/particle shearing, lengthening the required times for separation. When this happens, producers tend to spend too much money on oversized surface facilities. This is usually a waste of money.

So, 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 off of Gunbarrels*
- *recirculating interfaces*
- *recycling sump liquids back to the separation processes*

SOME CHEMICALS REDUCE DROPLET SIZES TOO

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*

<u>Corrosion Inhibitors:</u> 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.

<u>SCALE INHIBITORS:</u> 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).

<u>ACIDS:</u> Acids are used for well stimulation. By definition, acids have very 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 very small (usually less than one micron) solids particles carried back to surface treating facilities by spent acids.

<u>FRAC POLYMERS/GELS:</u> 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 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.

<u>OIL-WATER SEPARATION AND RETENTION TIME</u>

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 for the desired separation takes place.

A key factor contributing to oil-water separation in facility design is the prediction and determination of <u>real</u> retention time.

From the above it is obvious that <u>droplet or particle size</u> is the most critical factor when attempting to predict what retention time may be needed, since it is the only exponential function in Stoke's 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 probably 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.

It is clear that too much money has been wasted on poorly designed, oversized surface facilities throughout the history of the oil industry. Unfortunately, this trend has not slowed. In fact, in "boom" times like these, just the reverse is true. This happens because the industry is limited in human resources, so it focuses on the larger issues, letting issues like this go unattended. This also has happens 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.*

When faced with the prospect of a new prolific oil well, shut in and waiting for surface process facilities, efficiency often takes a back seat. Even today, most surface facility designers copy what was done the last time, particularly if it seemed to work. This perpetuates the mistakes of the past. So, it is important that we understand it is possible to find the right balance between separation needs, retention time, surface facilities design, and cost.

With a basic knowledge of separation, it is possible to leverage the available technologies and good operating practices to optimize surface 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 1000-barrel capacity process facility. This makes sense, or does it?

Well, each year hundreds of retention time studies are performed worldwide. They confirm that the fact that the actual retention time of most facilities is only a small fraction of the 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.

In reality, the design goal of 100% hydraulic efficiency is rarely approached. When 100% hydraulic efficiency is achieved, flow velocities are so rapid that mixing occurs, instead of separation. So, a hydraulic efficiency that is too high can cause mixing rather than separation.

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 of 1-21% is totally unacceptable for most of us, no matter what the subject.

A better system is clearly needed, and warranted!

In order to increase the hydraulic efficiency in oil-water separation process vessels the designers 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%.

Some attempts have had a negative effect 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. 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.

Let's consider a sample water clarifier process vessel. When the flowing velocity of any oil droplet exceeds separation velocity for that droplet, all droplets of that size, or smaller, fail to separate. Most of these droplets flow out with the water.

The point to be made here is that separation is interdependent of both 1) retention time, and 2) proper fluid flow characteristics. Unless <u>both</u> are correct, separation suffers.

This is further explained by an example. When an oil droplet flow velocity exceeds the Stokes' Law oil-water separation velocity for that droplet, that oil droplet (and all the same size or smaller) is carried with the water phase to the water outlet. The point to be made here is that separation is interdependent upon both 1) retention time, and 2) proper fluid flow characteristics. Unless <u>both</u> are correct separation suffers.

<u>AN EXAMPLE CASE</u>

To bring all of this into focus, let's 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 20 barrels per day. Therefore, the 20 B/D oil flows through 1000 barrels of stored oil in the Gunbarrel. By dividing the oil capacity of the 1000 barrel Gunbarrel by the 20 B/D production, it is easy to see that the ideal oil retention time is 50 hours.

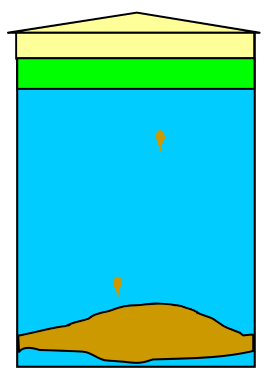
In this example the ideal crude oil retention time is 50 hours based on the "tank volume versus flow per day" formula. To determine the <u>actual retention time</u> an oil soluble dye tracer was applied in the field. The results showed a peak concentration after 1-1/2 hours, and zero concentration of the tracer after three hours. Therefore, the 3 hour actual divided by the 50 hour calculated results in an actual 6%

hydraulic efficiency. If the oil does not dehydrate in three hours' time, a larger of different design must be employed.

THE FOCUS SHIFTS TO WATER QUALITY

With the advent of large scale waterfloods in 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 to 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 look often looked like the one in Figure 4.



TYPICAL SKIM TANK
FIGURE 4

Field tracer surveys proved that short-circuit flow paths do exist in nearly all 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 last 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.

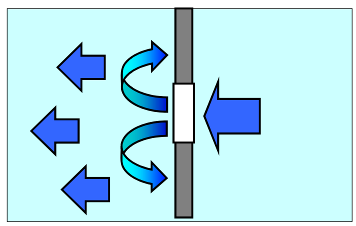
More and more test results proved that most of these new designs still had low hydraulic efficiency, and in many cases even poorer separation. It seemed that adding baffles simply caused more mixing, and more re-entrainment rather than achieving the expected increases in separation efficiency.

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, for the most part, they proved to be too costly or too unreliable. Furthermore, the poorest of the new designs were proven to have hydraulic efficiencies 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**.*

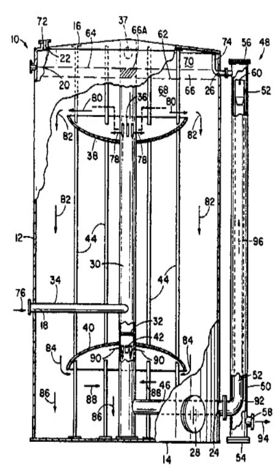
The reason for this is that most of the various methods of increasing retention time, such as vertical baffles forcing a serpentine flow pattern through a skim tank, increase the horizontal flowing velocity of the fluid to a rate greater than the separation velocity of the separable fluid fraction. Obviously,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



Eddy Currents in Orifice Flow
FIGURE 5

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 usually 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 due to this acceleration is greater than the vertical separation flow rate, separation ceases and mixing occurs, as in Figure 5.

Furthermore, flow path studies have proven over and over again that altering flow direction can cause re-entrainment of separable fluids. As the flow of a fluid exits any office, the pressure drop produces eddies which wrap around back toward the orifice, increasing the flow velocity even more, shearing and mixing larger droplets into smaller droplets and re-entraining dissimilar fluids. Obviously, these forces are detrimental to separation.



HWSB™ Skim Tank
FIGURE 6

HWSB™ SKIM TANK-GUNBARREL DEVELOPED, TESTED AND PATENTED

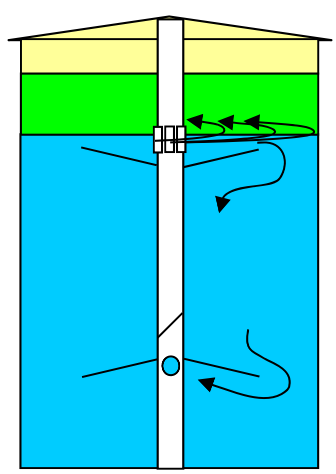
Then in 1985, the oil boom

came to an end. The price of oil fell from $45.00/barrel back into the teens, and finally settled in the single digits at $9.50/barrel. The strong financial position of the industry vanished almost overnight.

Knowledge took a back seat to survival. The lessons learned, and a large portion of the industry's knowledge base was lost as newly hired professionals and senior staffers alike were the victims of lay-offs and early retirement programs.

One survivor of this inevitable downturn was the desire by HTC's principal to stay the course, doing what was necessary to develop an efficient and simple gravity flow oil-water clarifier that improves performance to more reasonable levels.

Work continued through the down-cycle was scaled back, but continued, nevertheless. New designs slowly evolved, were tried, and fine-tuned. Each gave way to the next until the design, dubbed a "Hydrodynamic Water Skimming Breakthrough", or HWSB™ seen in Figure 7 at the right, was developed and field proven.



HWSB™ Skim Tank
FIGURE 7

Finally, in 1991 HTC's principal was granted Patent Number 5,073,266 on a system that accomplishes the goal of clarifying produced water to injection/disposal water quality! This was followed by Patent Number 2,053,326 in 1996. The new technologies were trademarked and officially labeled "HWSB™". Every HWSB™ is engineered and designed for each individual application under the watchful eye of the named patent holder, and owner of High-Tech Consultants, Inc...

The HWSB™ was a wide departure from all previous conventional wisdom. Its design is quite unusual. It has no moving parts. It applies many concepts not found elsewhere in oilfield processing. It looks outside our industry for methods proven sound in other types of fluid handling. It clarifies water. It approaches the ideal condition of piston displacement, resulting in very efficient, repeatable, and forgiving separation efficiencies.

By altering the standard design slightly, the HWSB™ can become a 21st century crude oil dehydrator as well as an ultra-efficient water and oil clarifier in high water cut applications.

Most importantly, the HWSB™ is the 21st century's ideal skim tank.

Adding to its beneficial features, where suspended solids like iron sulfide or oil coated formation fines, create interface layers or settle to bottom further proven additions to the basic design control these conditions so they no longer affect water or oil *quality. Interface draw offs are standard in all HWSB™s today. When the standard HWSB™ is modified with proven solids and interface removal systems, cleaning and normal maintenance can also be prolonged almost indefinitely.*

The operation of HWSB™ Skim Tanks was further improved with the hydraulically engineered water leg; another industry first. HTC hydraulically engineered, tested, and proven concentric water legs provide for low pressure drop and large spillover weir areas to maintain the most uniform and stable oil-water interface inside the HWSB™, where stable levels are critical to oil recovery performance. Then, HTC added an externally adjustable water leg design that allows the operator to manage the HWSB™ interface levels without affecting the process in any way (no shut-downs, nothing to de-pressure or drain!). This high-tech improvement has been well extremely received by all lease operators, providing more operating flexibility to put more oil in the sales tank whenever possible, and cleaner water in the water tanks!

THE HWSB™ DESIGN

The correct and proper design of each HWSB™ process vessel is an arduous engineering exercise, and it is quite time consuming.

The inlet fluid velocity MUST be slowed to less than rise and fall rates of the contaminants in the water phase. This must be done carefully, and in stages, so the oil separates upward to the top of the vessel, and the solids separate downward to bottom. Changing the direction of flow is necessary in this process, so avoiding shearing and mixing velocities is critical.

The annular spaces created by the tank walls and internal spreaders are carefully sized to accomplish this up to the maximum flow rating of each HWSB™ system.

Over 90% of the oil separation that is going to occur in the HWSB™ design occurs above the inlet spreader. The remaining remnant oil exists in such small droplets that they carry over with the bulk water flow as it turns downward in the upper annulus area.

The eddy current created by a properly sized annulus then pulls the bulk water up and under the upper spreader where it redistributes into a near-perfect plug flow (piston displacement) flow pattern. Here the bulk water velocity is dramatically reduced enough so the smaller oil droplets can separate. As they rise they are collected and flow into the oil phase near the top of the vessel, without having to traverse through the water phase again, where they would surely be re-entrained.

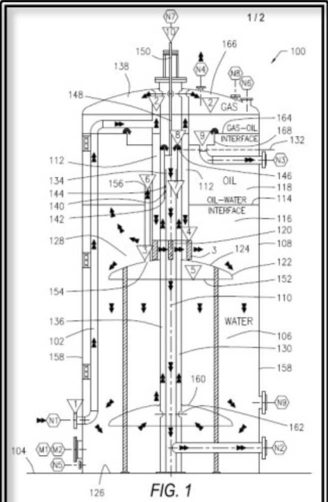
The application specific HWSB™ manages all fluid flows and velocities to maximize gas-liquids, water-oil, and water-solids separation.

The overall hydraulic efficiency approaches 72%. This is now *considered the real-world maximum, beyond which mixing energy take over and reverse the otherwise very efficient separation efficiencies.*

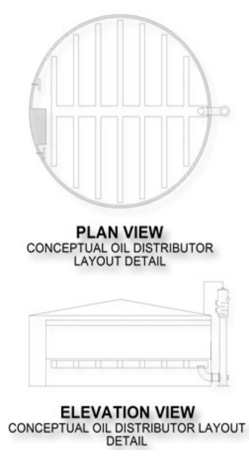
THE NEWEST COLD WEATHER HWSB™ DESIGN

As the current oil boom propelled the industry to develop production in the north in colder climate areas HTC designed, developed, tested, proved, and patented a new Cold Weather HWSB™ with the emphasis on freeze protection. This was perceived to be a valuable addition for the large Bakken Field in North Dakota, and for all of other very cold weather producing horizons where wintertime operations demand a focus on freeze protection.

HTC's innovative Cold Weather HWSB™ was successfully tested in the winter of 2010-2011. It exceeded HTC's expectations, and the expectations of the first end user. A patent application was prepared and filed in April 2012, and the Patent 8,496,740 was granted to HTC on July 30, 2013.



HTC's Cold Weather HWSB™ Patent Drawing Oil Dehydrator
Figure 8



HTC's HEGB™ Oil Dehydrator
Figure 9

OVER 1000 SKIM TANKS

Today, over one thousand HWSB™ Skim Tank systems are in service in the domestic oilfields of the United States. Many more are working to clarify oil and water in the international oil industry. Each one is setting the pace as a 21st century standard of the industry, replacing the API Gunbarrel in high water cut environs. Every HWSB™ is designed for its specific application, since most process conditions vary from lease to lease. And to date, every single HWSB™ has outperformed the best expectations of its owner, regardless of the conditions.

AN EFFICIENT, 21ST CENTURY TRUE CRUDE OIL DEHYDRATOR (GUNBARREL), AT LAST!

Not all crude oil treating applications are faced with high water cuts. Some applications still have a need to dehydrate large quantities of oil with smaller concentrations of water in atmospheric vessels. For these low water cut applications HTC developed 21st century high efficiency crude oil dehydration Gunbarrel (HEGB™). This unique design focuses on *maximizing crude oil dehydration rather than water quality. Oil with up to 30% water and emulsion is the target process stream.*

Since the biggest need is for for large volume production streams, many HEGB™ applications are retrofits in existing large API650 tanks, or for new applications in these tanks of the appropriate size. Smaller shop fabricated versions are also common when produced oil volumes are lower.

The HEGB™ scales up and down linearly. It is an equally efficient system in small and large tanks alike, where the design loading in terms of barrels per day per square foot of tank cross sectional area are identical.

The HEGB™ uses a hydraulically under-balanced distribution system 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. 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. This HTC design has been proven to be more efficient than conventional Gunbarrels in applications worldwide, ranging from 1500 BOPD to 250,000 BOPD.

HTC's SCOPE

HTC provides the entire engineering design spectrum from to individual vessels to the entire facility starting with the PFD, P&ID, and component drawings through with completed with detailed civil and mechanical engineering packages, all in AutoCAD, MS Excel, and MS Word. Transmittals are always via email to avoid delays.

HTC has designed over 400 HWSB™ Skim tanks, which are in service today outperforming the owners' expectations. We have designed scores of Salt Water Disposal (SWD) plants, tank battery facilities, and specialty plant for dozens of loyal and satisfied clients.

In its 20th year of continuous business, HTC is proud to bring much needed intellectual properties into the real world of a thriving oil industry.

ABOUT THE AUTHOR

Bill Ball has focused on oilfield facilities design throughout his oilfield career, which began after his university studies in 1963. In the 50 years since Bill has accumulated a unique knowledge of oilfield separation facilities, hydraulics, oilfield chemicals, all enhanced by hands-on experience. Bill currently holds five patents *for his designs used in hundreds of oilfield separation facilities everywhere.*

Bill is founder and president of High-Tech Consultants, Inc. located just outside the City of Tulsa, Oklahoma in the suburb of Bixby.

ABOUT HTC

HTC was incorporated in 1993 in Tulsa, OK to provide various proprietary and patented design technologies to the oil and gas industry. These include the patented warm and cold weather HWSB™ Skim Tank (Gunbarrel), the HEGB™ Crude Oil Dehydrator, Flow Splitters, Sand Tanks, Heater Treaters, Separators, Dissolved Gas Flotation Cells, and many others. HTC is an industry leading design firm for 21st century salt water disposal (SWD) plants and all oilfield facilities.

This HTC Patented 4' x 16' Horizontal Heater Treater in one of 300 in Service in the Eagle Ford Today.

HTC is proud to be able to share this paper with those interested in improving their oilfield water-oil-gas separation operations.

HTC is proudly responsible for every individual HWSB™ design. HTC's attention to detail assures each and every owner of an HTC HWSB™, or any of its other designs/technologies, of the unprecedented success in each and every unique, oilfield application.

PICTURES OF HTC FACILITIES

Here a single specialty horizontal heater treater processes Eagle Ford Crude once processed by several vertical treaters just a few years ago. Above, a hot oil system replaces an unsafe firetube tank heating system, a FRP DAF clarifies 30,000 BWPD, and three Skim Tanks recover 1,500 BOPD from inlet produced water. All of these are HTC specialty designs.

Fiberglass Flotation Cell

This 30' OD HTC Flotation Cell Polishes the Last Remnants of Oil from Produced Water

HTC 3,000 BOPD Crude BS&W Treating Facility

Three HWSB™ Skim Tanks

Flank Three HTC Polishing Tanks in a 30,000 BWPD SWD Plant