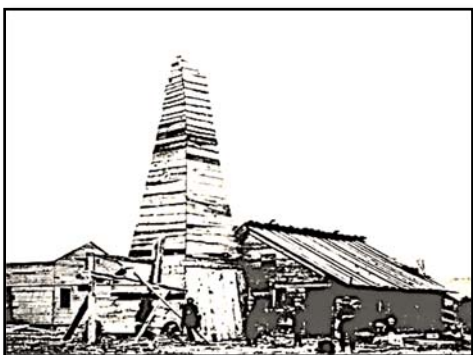


The Ideal 21st Century Central Tank Battery

Separation and Storage Facilities have Changed with the Times



Typical Tank Battery
Circa 1859



Typical Tank Battery
Circa 1985



Typical Tank Battery
Circa 2021

A Technical Paper

Prepared for

**All Oilfield Operating
Personnel**

Paper by:

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June 1, 2021



2021 Tank Battery Design

How Oilfield Surface Facilities Have Improved

EXECUTIVE SUMMARY

The design of oilfield tank batteries has changed over time. In 2021 the process requirements are far more complex than they were even a decade ago, and infinitely more complex than they were in the early days of the oil industry.



For over a century all wells were completed vertically. Now, most are completed horizontally. Today's prolific production rates, resulting from fracked horizontal completions, have ushered in a whole new set of process conditions and challenges that didn't exist a decade or so ago.

These have forced us to question older design engineering practices for tank batteries and their various components, and to adjust accordingly.

Today we must also concern ourselves with carbon footprint, EPA constraints, OSHA mandates, crude oil RVP, pricing penalties for off-spec oil, oil carryover, water quality, flaring restrictions, emissions, oil spills, and many other issues. Our designs need to achieve better results than ever before.

Advancements in electronics have us leaning toward more use of electronic controls from the Internet of Things, while downtime costs push us to maintain our older, simpler, more easily understood, and more rapidly repaired systems.

Happily, there is a practical and economic balance in all of this. This paper was written to help you achieve that balance.

THE 2021 TANK BATTERY



Each properly designed and operated tank battery is a small "process plant". It takes in raw oil, gas, and sediments and produces pipeline quality natural gas, pipeline quality crude oil, high quality water suitable for reuse as frac water, or adequately clarified to be reinjected in the producing reservoir or some other suitable formation without plugging the wells.



Tanks no longer vent to atmosphere. Instead, 100% of all natural gas is captured by dedicated "Vapor Recovery Units", eliminating concerns over natural gas related carbon footprint.



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This document was prepared
for the loyal clients of Breakthrough Engenuity

Oil is dehydrated to below the normal 0.5% BS&W pipeline oil quality standard in heater treaters designed to dehydrate oil and manager crude oil RVP.



Produced water containing an average of 1% residual crude oil is now clarified in dedicated water clarifying "Skim Tanks" which produce water with less than 30 parts per million of oil and grease.

All process facilities are located in dedicated containment systems to eliminate soil contamination and concerns over run-off.



Topics like global warming and carbon footprint were not even in our vocabulary when the EPA was formed on December 2, 1970.

Today there are very few people alive who can recall what we did in 1970, or why. The industry's many booms and busts resulted in so much attrition it was been difficult to maintain technical continuity. After each bust, we tended to revert back to what we did last time, particularly if it worked. There was no internet, or an "Internet of Things". And so, we tended to repeat the past; cautious to try something new.



Now, in reaction to new conditions, we have dramatically changed the way we do almost everything! Though every well drilled two decades ago was completed vertically, most wells drilled today are completed horizontally. Shale oil, not economically producible at the turn of the century, is produced so prolifically today that it dominates US refinery feedstock.

And, the design of surface facilities has advanced too. This paper attempts to bridge any knowledge gap in past decades, and to document the driving forces and technologies that have ushered in the designs of today's "ideal tank battery".

BETTER RESULTS

In the past we were satisfied with tank battery process results that gave us pipeline quality oil so we could sell it at the posted WTI price level without penalties. Gas effluent quality was of little concern, even when oil carryover was significant. And water quality was often not even a consideration.

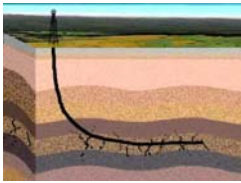
We strive for more in 2021. We still look for pipeline quality oil, of course. After all, we are an "oil industry". But, today, we are equally interested in the quality of the gas and water streams leaving our facilities. Oil carryover has cost the production side of industry billions of dollars, so we make every reasonable effort to eliminate oil carryover in our gas streams. The same is true for oil carryover in our effluent water streams. It has averaged



over 1% in past decades, or from 70,000 to 90,000 barrels per day! Today, we strive to clarify our effluent water streams so more of the produced oil is captured and sold on-site.

By minimizing oil carryover in our gas streams, and by reducing oil carryover in our effluent water streams, today's "ideal tank battery" is significantly increasing the net oil revenue generated at the tank battery level.

MORE PROLIFIC PRODUCTION



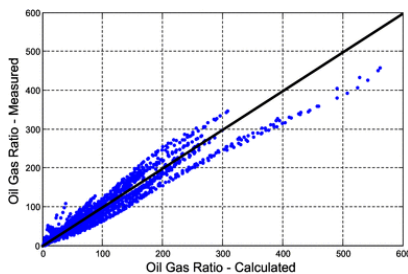
Today's horizontally completed wells are amazingly productive. The larger exposure of its oil-bearing rock translates to new wells averaging over 3,000 BOPD of light, high API gravity crude, or more! This is roughly ten times greater than it was in 1980! Newly completed horizontal wells also typically produce more natural gas and more water too.

Most of the production process equipment available today was designed before 2010 when produced oil, water, and gas volumes were far lower, and the typical crude oil API gravity was much lower. As we made the transition into the age of horizontal completion and multi-stage massive frac jobs, the technical attrition the industry took its toll. Outdated tank battery designs struggled to keep pace with the dramatic production increases. Some shale oils were high in paraffin content, and had unfamiliar foaming characteristics. Vessel sizing and internals standards had to be reconfigured to prevent marginal process equipment operations, or in many cases, outright failures. Oil and water storage had to be increased. And a new emphasis on water clarification was needed to prevent oil losses from oil-in-water carryover. Everything had to change!

And, it all begins with an emphasis on gas removal.

THE 21st CENTURY SEPARATOR DESIGN

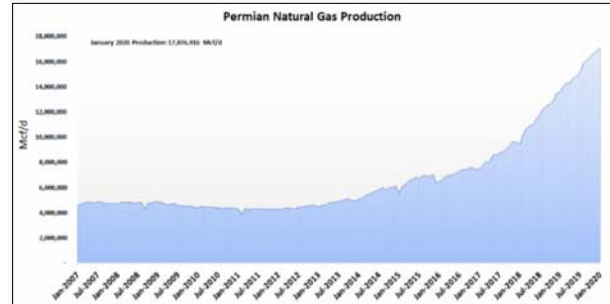
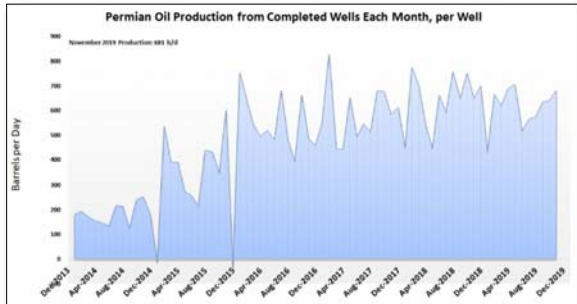
Separators are used to remove natural gas from produced fluids. These separators are pressure vessels designed for the direct transmission of produced natural gas into nearby gas collection (gathering) pipelines. By definition, when the gas-oil ratio (GOR) is above 100 MCF per barrel of oil, wells are classified as gas wells; otherwise, wells are designated as oil wells.



The theoretical GOR of any well tracks the theoretical determination reasonably well, as can be seen in the graphic at the left. From this graphic we see that a 2021 oil well producing can be expected to have an actual GOR of from 6 MCF/BBL to about 12 MCF/BBL.



However, in reality, actual gas production rates are always a fraction of the maximum, as we see in the graphics below for the Permian Basin, the largest oil producing basin in the US, approaching six million barrels per day at this writing.



These graphics show us that actual GOR in the Permian Basin ranges from about 0.76 MCF/BBL to about 1.54 MCF/BBL. The typical new well produces from about 1500 BOPD to about 3500 BOPD. Production declines are fairly rapid, so that by the end of the first 30 days or so, typical oil production rates are in the 1,000 to 2,500 BOPD. This means the typical oil well may also produce gas at a GOR of about 1.15, or from 11.5 MMSCFD to 25 MMSCFD. These GORs and gas volumes are ten to twenty times those from vertically completed typical wells, and, since most separator designs were generated prior to the widespread acceptance of horizontal drilling, it is no surprise that those separators struggle to perform today. Clearly, process system designs need to be updated to match today's oil and gas drilling and producing conditions.

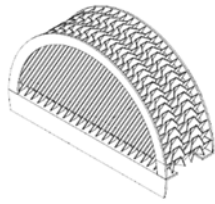
It all starts with the gas separation system; the first vessel to receive wellhead produced fluids.

The 21st century separator is always horizontal. This configuration maximizes separation efficiency. It first receives the inlet fluids and distributes them in a flow dividing inlet diverter. This diverter slows the velocity of the fluids, and distributes fractions of the bulk flow across a wide area of the inlet. This minimizes the momentum of all fluids, and shearing forces which can defeat separation.



Gas, being significantly lighter than either water or oil, separates upward in a ballistic trajectory shortened by virtue of the greater specific gravity difference of gas and associated liquids. The gas stratifies into a layer above the liquids.

Oil, being heavier than gas but lighter than water, accumulates below the gas layer. Water and solids, being heavier than gas and oil, settle to the bottom. This is "gravity" separation, and it performs according the laws of physics; Stokes' Law in these cases.

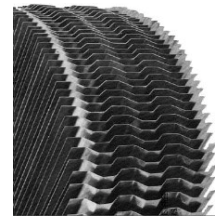


When foaming is expected, a set of "foam breaking" parallel plates is added near the inlet. This is made up of a series of closely spaced and inclined "Lamella" corrugated plate impingement baffles placed in the gas phase only. Foam bubbles impinge on the surface of the plates, breaking the foam into liquids and gasses. As the foam breaks, liquids rain down off of the inclined plates, taking advantage of the Lamella effect.

Downstream of the foam breaking section remnant microdroplets of oil and or water separate into the liquid layer as and gas flows horizontally towards the outlet. Near the outlet end of the separator the gas flows through a second set of Lamella plates for final removal of virtually all entrained oil. The spacing of these plates is often closer than the in defoaming case.



The second set of plates extends from the top of the vessel through both the gas and the oil layer, ending just below the oil-water interface level so all of the produced oil and defoamed gas MUST also flow through it. This set of plates demists the gas phase, which then exits through a gas meter and on to sales. It also coalesces produced water droplets entrained in the oil phase allowing them to coalesce and separate more rapidly. As these larger water droplets coalesce, they fall downward and into the water layer below, thereby removing bulk water from the oil.



However, there are no coalescing vanes in the water phase because such devices are known to foul rapidly. With no coalescing media to traverse the water quality is always less than ideal. The typical heater treater will "carryover" between 1% and 5% oil-in-water. If the water volume is high, the carryover volume of oil will be high as well. This will nearly always justify a specially designed downstream oil-water separation, or "Skim Tank", with patented retention time enhancing internals (all described in detail starting on Page 11).



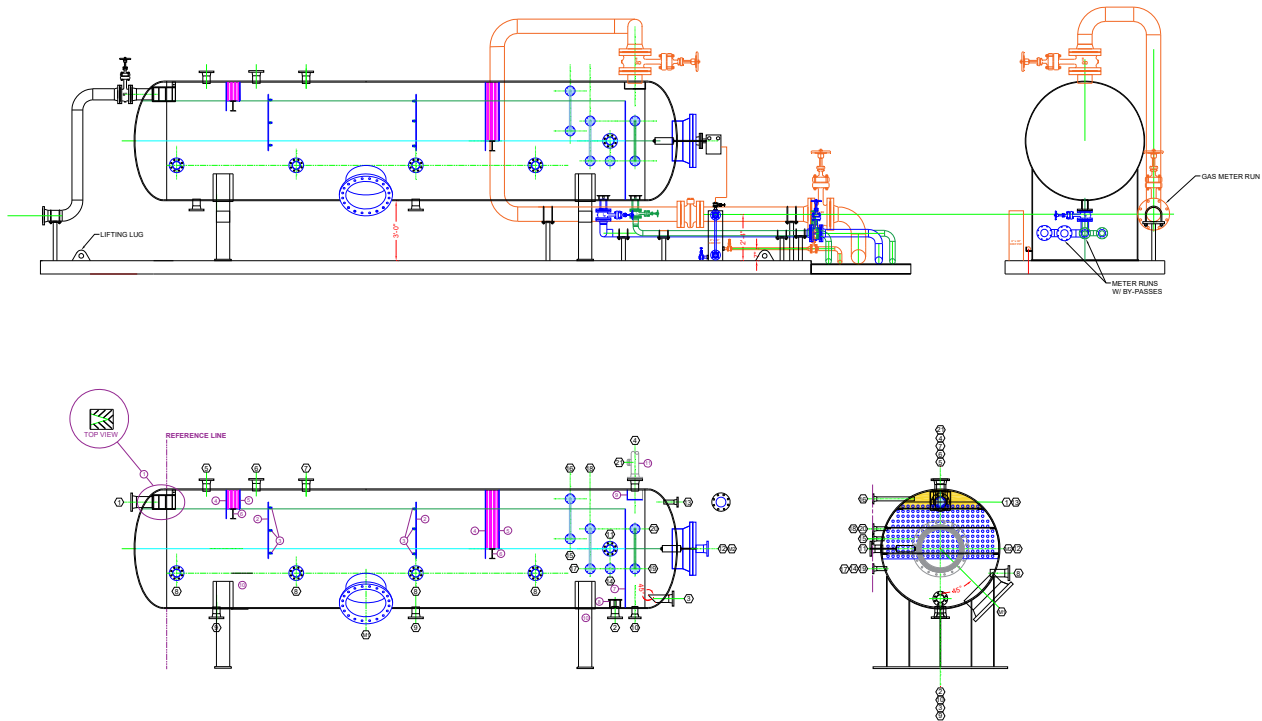
Taking all of this into consideration, the ideal 21st century separator can best be described as a low, medium, or high pressure horizontal three phase skidded metering separator with a pressure relief valve, an oil-water interface controller, an oil-gas interface controller, high and low-level shutdown controls, separate oil, water and gas metering systems, with linear throttling oil and water outlet valves and internals as described herein.

The performance targets for the 21st century separator are:

1. **GAS QUALITY:** Less than one tenth of on barrel of oil per one million standard cubic feet of effluent gas sold to a third-party gas gathering firm.
2. **OIL QUALITY:** Less than 10% BS&W with the process goal of achieving less than 5% BS&W in the oil to downstream heater treater.

3. WATER QUALITY: Less than 3% oil-in-water carryover effluent to a dedicated oil-in-water skim tank designed to produce a net oil carryover of less than 50 parts per million.

This 21st century separator will look like this:



21st CENTURY GAS FIRED HEATER TREATER DESIGN FEATURES

Treaters are designed to remove water, sediment and residual natural gas from produced oil. Most do this by first heating the crude oil, which lowers its viscosity. By lowering the viscosity of oil, all contaminants separate from it more rapidly.

The 21st century heater treater is a horizontal low-pressure vessel. The horizontal configuration allows for heating elements (firtubes) to be long enough to safely transfer the required heat into the oil. This heater treater will be operated at just enough pressure to hydraulically move the fluids it processes to their downstream destination without pumps, though the gas may have to be recompressed to move it to the gas gathering pipeline.

Heat transfer is a physical phenomenon. Heating is commonly accomplished by direct heat transfer using a natural gas burner to generate an intense flame inside of a "U" shaped firtube (pipe) immersed in the produced oil phase in the 21st century heater treater. The heated firtube transfers its heat into the oil outside the firtube. The heat flux rate should be kept

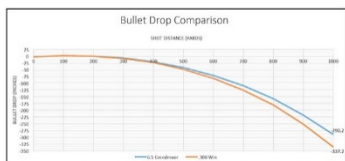


below 10,000 BTU/hour per square foot of firetube surface area to achieve acceptable firetube performance without destroying the firetube pipe.

It takes 350 BTU to heat one barrel of water 1°F, and only 150 BTU to heat one barrel of oil 1°F, heating water does not change the viscosity of water or augment separation. Heating crude oil, on the other hand, does decrease its viscosity, and dramatically enhances the separation of contaminants from it.

The design of the 21st century heater treater provides first for bulk gas separation. This is accomplished by splashing the inlet fluid stream downward onto a hot horizontal baffle plate which spreads the fluids out into a thin layer from which gas can rapidly escape. This impact plate is sealed, so gas exits through a 180° crossover to the bulk area of the treater.

Degassed liquids flow to either side of the impact plate, and downward in a shrouded area isolated from the bulk liquids. This shroud is placed close to the walls of the firetube, so it is heated, and thereby pre-heats the inlet liquids. Once the inlet fluids are heated, they are distributed into an inverse trough where the fluid velocity is reduced to allow sufficient time and space for the fluids to begin to separate inside the open-bottom trough. As the oil and water separate inside the trough, oil depresses the oil-water interface inside the trough. Oil metering holes are drilled in a horizontal line just below the top of the trough. These holes uniformly distribute the oil and emulsion out of the trough and into the heating section of the heater treater, and below the bottom of the firetube where oil rises to be heated, and water falls downward only partially heated.



As fluids separate, larger and heavier droplets of liquids flow downward in a "ballistic" trajectory. The trajectory of the emulsion droplets depends on the size of each droplet. Larger droplets have a more rapid, shorter trajectory because of the density difference between water and oil, and the viscosity of the oil (again, all according to Stokes' Law of gravity separation). Smaller emulsion droplets are carried farther horizontally in the moving oil stream, and the smallest may even be carried out with the outlet oil.

The ballistic trajectory for oil droplets in water is the reverse as the water flows through the heater treater. Larger oil droplets separate upwardly and rapidly, whereas smaller oil droplets (inverse emulsion droplets of oil) may rise so slowly that some may be carried out of the treater with the water. When the horizontal velocity of the water is greater than the rise rate of the oil droplets in it, those oil droplets will be carried over with the water. The volume of "lost" (carryover) oil can be quite significant, justifying a downstream effort to recapture it.

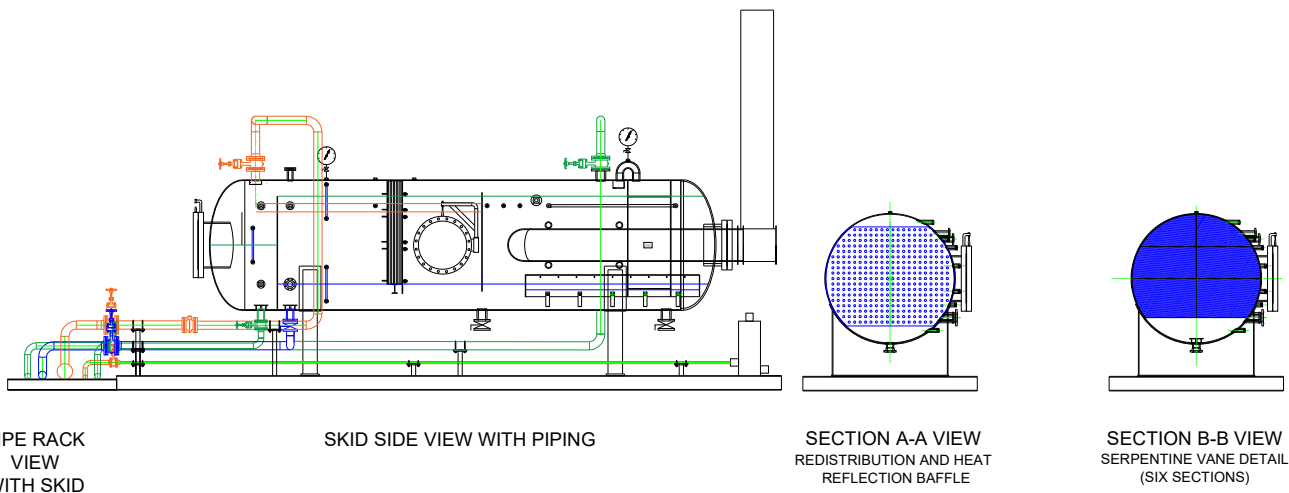
The 21st century horizontal treater is designed so the inlet fluid flows around the firetube to be heated, and then horizontally to the outlet. As the oil reaches the end of the firetube it flows through a redistribution baffle designed to provide for the lowest velocity and the most



uniform flow path of the oil in the treater. As the redistributed oil flows toward for the oil outlet, it flows through a set of inclined Lamella-style serpentine vanes located about three-quarters of the length of the vessel from the inlet. These corrugated parallel plates remove the very smallest droplets of water in the oil, thereby conditioning the oil quality to the highest degree for storage and sale. The clean oil then spills over a baffle and flows out to the oil storage tanks.



The water flows from below the firetube at the inlet the length of the treater to the water outlet connection where it leaves the treater. There are no coalescing vanes in the water phase, as such devices are known to foul rapidly, so water quality is always less than ideal. The typical heater treater will "carryover" between 0.1% and 3% oil-in-water. If the water volume is high, the carryover volume of oil may be high as well. This can justify a downstream oil-water separation tank, often referred to as a "Skim Tank". The 21st century heater treater (heated horizontal separator) looks like this:

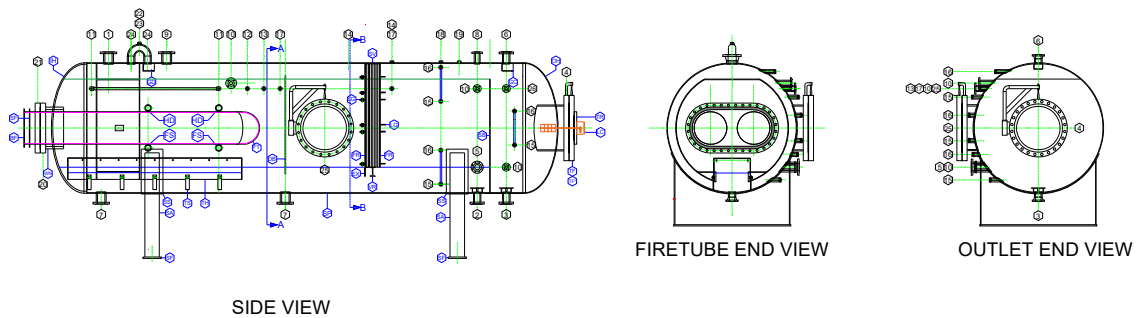


PIPE RACK
VIEW
WITH SKID

SKID SIDE VIEW WITH PIPING

SECTION A-A VIEW
REDISTRIBUTION AND HEAT
REFLECTION BAFFLE

SECTION B-B VIEW
SERPENTINE VANE DETAIL
(SIX SECTIONS)



SIDE VIEW

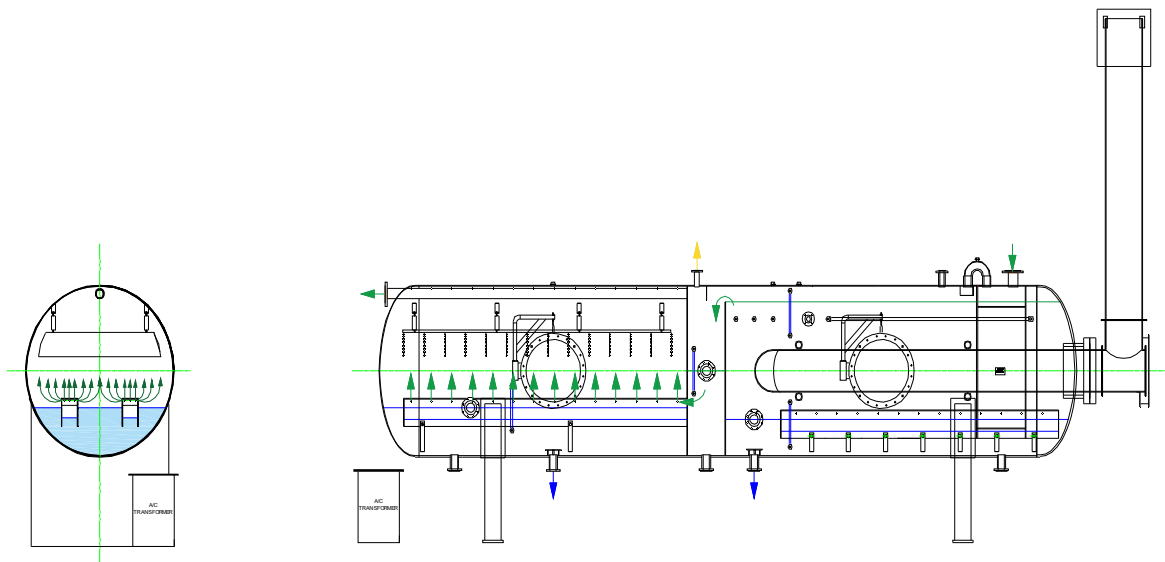
FIRETUBE END VIEW

OUTLET END VIEW



HEATER TREATER WITH ELECTROSTATIC COALESCING

When difficult to resolve emulsions are present, an alternate treater design may be beneficial. This alternate is an "electrostatic heater treater. The heating section of the electrostatic heater treater is similar to the conventional 21st century design, while the coalescing section is more sophisticated, using electrically charged plates to coalesce even the smallest emulsion droplets so they readily separate. This is the same basic and very mature technology used to condition raw crude oil in all crude oil refineries. It looks like this:



The performance targets for both of the 21st century heater treaters are:

1. OIL QUALITY: Less than 0.5% BS&W with the process goal of achieving less than 0.025% BS&W in the oil to storage/sales 24/7/365.
2. GAS QUALITY: Less than one tenth of on barrel of oil per one million standard cubic feet of effluent gas sold to a third-party gas gathering firm.
3. WATER QUALITY: Less than 1% oil-in-water carryover effluent to a dedicated oil-in-water skim tank designed to produce a net oil carryover of less than 50 parts per million.

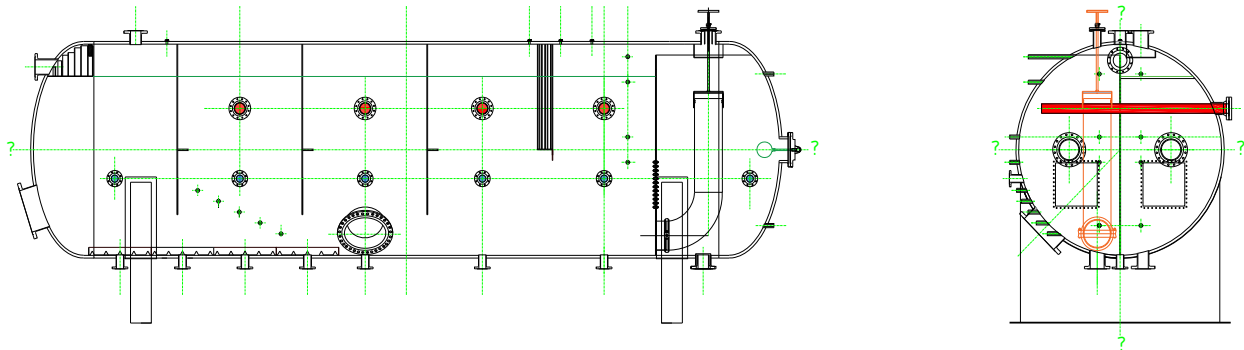
21st CENTURY ENVIRONMENTALLY FRIENDLY ELECTRICALLY HEATED TREATER DESIGNS

As OSHA and the EPA through recent modifications to the Clean Air Act put more pressure on oil producers to reduce or eliminate the generation and discharge of so-called "greenhouse gases", some producers are turning to process vessel designs that do not use the conventional gas-fired approach to heating. Some have proven that light gravity shale oils respond favorably to ambient treating temperatures. Others have found that ambient conditions may



propagate paraffin precipitation or contribute to high vapor pressure issues affecting the sale of their produced crude oil.

In order to offer the industry a solution to these issues, an electrically heated treater was developed and patented. It looks like this:



This treater utilizes the same high-efficiency Schoepentoeter-type inlet diverter, flow distributing perforated quieting baffles, Lamella-style coalescer/demister, and replaces the gas fired burner/firetube system with electric immersion heaters encased in stainless steel for ease of removal/replacement avoiding all vessel downtime related to the heating system. Perhaps the greatest advantage of this system is its superiority in efficiency. Gas fired systems are 15-25% thermally efficient, wasting 75-85% of all heat (lost to atmosphere up the burner stack (chimney)). The electrical heating elements, by contrast, distribute 100% of all heat into the surrounding fluids, wasting nothing. They also generate zero emissions, satisfying the requirements of the EPA and the latest revisions of the Clean Air Act.

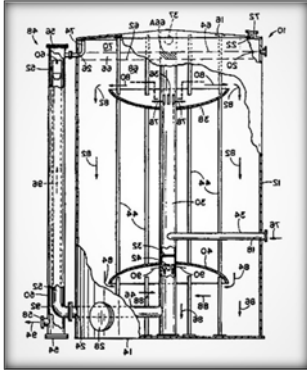
THE NEW FOCUS ON WATER QUALITY

Produced water effluent of separators, heater treaters, and FWKOs contains between 0.5% and 3% crude oil. This oil can be captured and sold at the tank battery, or it can be sent to a nearby salt water disposal plant, and lost to the producer forever. The greatest benefit to oil producers comes when all oil is captured and sold at their tank battery facilities.

The fact is that until recently most production facilities avoided the issue of capturing oil entrained in produced water. During earlier decades, water volumes had risen to exceed oil volumes by as much as a factor of ten, and because of this, entrained oil volumes began to get the attention of SWD operators. More water tanks were installed at most SWD plant to capture this oil. But still, water with 0.5 to 3+% oil (and sometimes more) was pumped into disposal wells where it was lost forever. The produced water, with all of its oil, was simply hauled or pumped offsite to a nearby salt water disposal (SWD) facility. Prior to 1990 most of



the entrained oil remained in the produced water and was pumped into deep disposal or water injection wells, and lost forever.



However, in 1992 a patent was granted for an oilfield skim tank that has proven to be a far more efficient skim oil separator than the water storage tanks and Gunbarrel tanks previously in use. This was the first "hydro-dynamic water separation breakthrough" or "HWSB®" skim tank. It has radically different internals compared to the oilfield "gunbarrel" tank; internals that maximize oil and water retention time and nearly completely separate all oil from water. The internals can be seen here in the patent application drawing. The HWSB® became a standard of the industry and is now used by operators who want to capture the saleable oil in their produced water and improve water quality to below 50 ppmv oil in water in their various facilities.

The HWSB® has been improved over the years and all improvements are also patented. Every HWSB® reduces inlet oil-in-water concentrations ranging from the 0.1% to 3% or more oil to effluent concentrations of less than 50 parts per million of oil-in-water. Fifty parts per million is equivalent to 0.00005 barrels of oil per barrel of water. It is believed that all the over 3,000 HWSB®s in service today have captured more than 12 million barrels of saleable crude oil since the turn of the century.

In 2014 this author's HWSB® patents were sold to KBK Industries to assure the industry that the technology would be preserved indefinitely. KBK is a leading supplier of API steel and API fiberglass oilfield storage and other processing and storage tanks.

CONTROLLING TANK VENT GAS

Since the typical separator and heater treater are operated at a positive pressure, a fraction of the produced natural gas remains in solution in the oil and water under pressure. As the oil and water leaves the separator and flows to the treater, the pressure on them is reduced and some solution gas evolves as free gas and it is separated in the treater under a slightly lower pressure. As the oil and water leave the treater, both flow at very near atmospheric pressure, allowing the gas in solution to evolve out of solution as the fluids reach the storage tanks. This adds to the volume of gas at atmospheric pressure normally evolving from the atmospheric storage tanks. These tanks are normally closed top tanks fitted with vapor vent valves which allow gas to leave the tank when a slight pressure is reached. As the tank pressure increases, the vent valves open to relieve the pressure.

In the early days of oil production, most vent gas flowed from the storage tanks into vent piping or directly to atmosphere. Later, this "waste gas" was directed to rudimentary flare systems that burned the gas. As environmental concerns increased, the rudimentary flare



system evolved into more sophisticated and efficient vapor destruction systems to minimize smoking and air pollution.

In order to reduce the volume of gas evolving at atmospheric pressure, and thus minimize either overall flare gas emissions, or the requirements for recompression equipment to capture and move this gas stream, one of two processes is often applied in the 21st century tank battery design. One popular system today is the Vapor Recovery Tower, or "VTR". The VTR is a basic "stage separation" which minimizes the evolution of natural gas coming out of solution from the produced, pressurized petroleum liquid stream. This minimizes the gas volume evolving in tankage at or just above atmospheric pressure. A pair of VTRs are pictured here at the right.



Before VTRs, produced oil leaving a heater treater flowed directly into atmospheric storage tanks. Gas evolution rates were relatively high. When a VTR is added, oil with evolving solution gas enters the VTR at the top, filling the tower with crude oil. The inlet oil falls through an internal downcomer pipe in the tower and exits near the tower bottom. Freely separating gas evolves from the crude near the top of the VTR where the pressure is lowest. The column height of the crude oil adds pressure to the oil deeper in the column, causing a more gradual gas evolution and stabilizing the crude. The result is a much-reduced volume of gas evolving from the crude oil. The stabilized crude oil flows up from the bottom of the VTR tower to above the top of the oil tanks where it is piped into the oil sales tanks.

Without the VTR the evolving gas volume in the tanks may exceed 500,000 SCF/hour for each 3,000 BOPD. With the VTR this volume is reduced to below 50,000 SCF/hour. The obvious result is a much smaller downstream gas processing system.

A second method was introduced several years ago. It is a "Stabilizer" column. This may be a packed or trayed column designed to nearly completely degas the crude. This tower may be heated to help flash remnant gas out of solution from the crude. This system is 2-3 times as costly as the VTR, and requires more instruments, valves, and controls, complicating its operation and maintenance, so it is mostly used only in operations that are manned 24/7. In either case, oil with far less entrained/dissolved natural gas then flows on the oil storage tanks.



21st CENTURY OIL STORAGE

After WWII the American Petroleum Institute (API) began its effort to standardize oilfield equipment through an ever-expanding series of "API Recommended Practices" published documents. These publications provided "standards" recommended for use throughout the industry. Oil storage tanks were one of the first subjects to be addressed in the API's Recommended Practices, API RP 12-B, 12-F, and 12-P have provided manufacturing guidelines for standard API tanks for decades, but in the 21st century these standards have proven to be



outdated and inadequate for today's prolific, often shale oil related, horizontal completion-related operations. So, operators have begun to deviate from the API RPs, and build facilities that make more sense in today's operations.

Whereas in the 1980s the standard tank battery was comprised of two 15'-6" OD x 16' high oil tanks, today's far more prolific production rates demand a larger number of larger tanks. In many cases these are now 15'-6" x 21' high, or 15'-6" x 30' high. There is no API RP standard for the later.

Furthermore, all oil inlet connections are located in the roof (deck) of these API tanks as a standard. This was originally done to minimize oil theft, since many older oil tanks were filled from the bottom. It was easy for oil thieves to tap into these low tank entrance connections and pump the oil out of the tanks. Filling through the tank roofs (decks) made it far more difficult, and helped minimize oil thefts for decades. Then, in the mid-1980s the EPA mandated testing to compare the effects of splash loading through the tops of vessels with bottom loading. The results showed that top or "splash" loading translates to several hundred percent more vapor emissions than bottom loading. As a reaction to this finding, some oil companies began to adopt the use of "downcomer" piping extending the roof inlet connections extending the oil inlets down into the tanks, terminating them about 12"-24" from the tank bottom. The API recognized this and amended its RP accordingly, adding an anti-siphon hole in the top of piping extension just under the roof (deck) of the tank to avoid the issue of back-flow or oil siphoning by potential thieves.

Today, more and more savvy tank battery designers are simply using connections near the bottom of oil tanks to eliminate splash loading and minimize tank vapor emissions. For security purposes, some operators use conventional "pipeline seals" on all oil line valves, so any/all theft can be easily spotted. However, the use of LACT (Lease Automatic Custody Transfer) Units is by far the best approach for 21st century oil producers to assure themselves that they are paid for every single barrel they produce.

LEASE AUTOMATIC CUSTODY TRANSFER (LACT)

LACT Units are often referred to as "the cash register of the oil patch". LACT Units are simple, automated volume and quality crude oil measurement systems. A pump moves the crude oil out of the storage tanks, through an electronic quality measurement device known as a BS&W (basic sediment and water) monitor, past a sampler which collects a representative sample of the crude, through a calibrated meter to determine the actual volume of the crude oil, and into the receiving haul truck or pipeline. The meter is calibrated every few weeks to assure accuracy.



Most oil shale operators today agree that LACT Units are a necessary component in each tank battery design to assure the accuracy of their oil sales and to avoid theft issues.



VAPOR RECOVERY

VRTs and stabilizer systems typically operate at 1-5 PSIG positive pressure. This slightly higher than atmospheric pressure minimizes the compression ratios, size, and reduces the horsepower requirement of the vapor recovery (recompression) units (aka "VRU") used to move the separated low-pressure gas from the VTR or Stabilizer to the nearest higher pressure gas collection/gathering pipeline. Such pipelines typically operate at below 150 PSIG, and often below 30 PSIG.



The typical Vapor Recovery Unit (VRU) is shown at the left. It is a skidded system comprised of 1) a small electrically powered rotary vane compressor and 2) a liquid-gas separator controlled by pressure switches mounted on the storage tank vent piping. As the pressure in that piping reaches a few ounces of pressure, the VRU compressor starts and by moving the tank vapors out of the tanks and into the gas gathering pipeline, it reduces the pressure inside the tanks. When that pressure is close to atmospheric pressure, the VRU compressor shuts off and the cycle repeats itself.

While many tank batteries are now fitted with VRUs, most are not. As the issue of minimizing greenhouse gas emissions in oilfield operations intensifies, the VRU will become a dominate tool used to minimize and eliminate natural gas emissions.

However, in the real world, all things eventually fail. When a VRU fails the produced gas must go somewhere. That "somewhere could be a vent, venting raw natural gas to atmosphere, or it could be a flare system used to burn the natural gas, converting it to mostly CO₂ and water. Since methane is a contributor to SMOG, a root cause of emphysema and lung cancer in humans, and CO₂ is a contributor to greenhouse gas emissions, these discharges are unacceptable under the Clean Air Act and MUST necessarily be prevented wherever possible, but when they occur, they must be dealt with.

21st CENTURY FLARE SYSTEMS

In earlier times all produced gas was vented to atmosphere. Gas lighting ushered in an era where larger flows of natural gas were captured and transported to population centers to be used for lighting, and eventually heating. As some large oilfield operations encroached on populated areas, air pollution and safety concerns saw oil operators install so-called "stick flares". These were joints of pipe stood up vertically so gas fed to them would escape above ground level. The gas was ignited and burned. When the gas contained sulfur, the smell was offensive, and taller pipes we installed to increase the dispersion of the burned gases. Pilot lights were added to prevent "flame outs". These flares were 80-90% efficient at burning the gases fed into them. Finally, in the middle of the last century, reacting the Clean Air Act, more sophisticated and efficient flares were developed which routinely achieved 98% combustion efficiency, and as later CAA Amendments tightened constraints, efficiencies rose to 99.5%.



Today, the oil producing (upstream) industry has flares of all types and efficiencies. In the past cost was the dominant decision maker. Today the Clean Air Act and tightening EPA regulations are the dominant factors, so more efficient flares are replacing older, less efficient flares.

Two types dominate today's applications. They are 1) air assisted smokeless flares, and 2) enclosed thermal oxidizers.

The air-assisted flare is a vertical stack with an air-gas mixing top and an air blower near the bottom to force air into the gas stream. This mixture of air and gas assures the very clean and thorough combustion of the gas smokelessly in a relatively short flare flame as see in the photo at the right.



Enclosed flares (thermal oxidizers, or T.O.s) are refractory lines cylinders with a burner/mixer near the bottom and inside the cylinder. Combustion air is throttled into the cylinder through temperature-controlled louvers also near the bottom of the cylinder. By controlling the temperature of the combustion reaction, the efficiency of this design is maximized. Another benefit of this design is that the flare flame is contained inside the cylinder, so all light emission issues are defeated.

CORRECTLY SIZED PIPING

An often-overlooked design issue is that of proper line sizing. When tank battery piping is too small premature failures occur due to high velocity erosion-corrosion. When piping is too large, the reduced velocity of fluid flow allows for separation within the piping which results in plugging and eventual flow failure. Both conditions should be avoided.

To avoid these pipe sizing issues, all tank battery piping should be sized for flow rates of 5-10 feet per second for liquids, and 30-50 feet per second for gas flow.

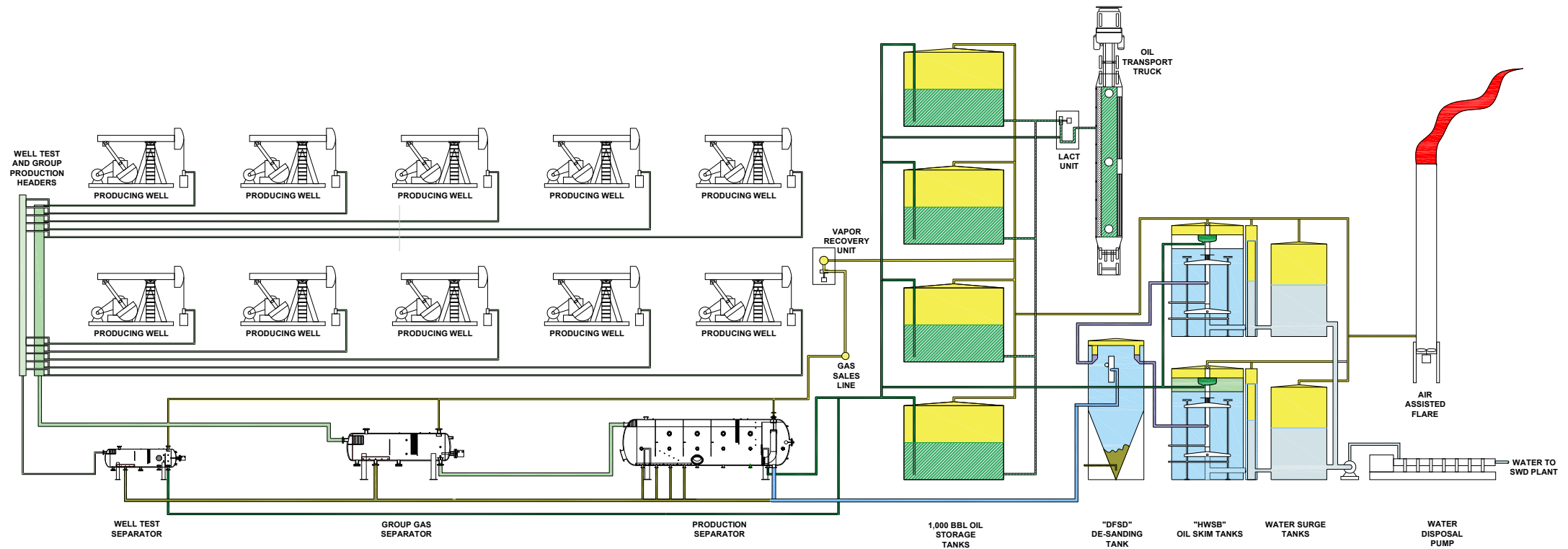
THE IDEAL 21ST CENTURY CENTRAL TANK BATTERY DESIGN FOR TODAY'S PROLIFIC HORIZONTALLY COMPLETED WELLS

The prolific nature of most horizontally completed wells in 2021 has prompted many producers to cluster wells into central tank batteries (CTBs). Many of these consolidate production from ten wells or more into a single CTB.

Such CTBs are designed to process (separate) the total oil, water and gas production from all wells feed in it. The production process equipment for ten wells is represented by the following graphic for ten well production streams where each typical well produces from 500 BOPD to 1500 BOPD, from 3,000 to 10,000 BWPD, and from 1.0 to 2.0 MMSCFD.



21st CENTURY TANK BATTERY LAYOUT



SUMMARY

With the shift from vertical oil well completions to long horizontal lateral well completions and successful shale oil production a paradigm shift is necessarily occurring where typical process equipment designs of just a few decades ago are being replaced with more appropriate and efficient 21st century facility designs. Operators are learning that the industry "standards" used before are no longer adequate for today's process conditions and facilities. This paper attempts to highlight some of these breakthrough designs.

BREAKTHROUGH ENGENUITY



In 1992 Bill Ball founded High-Tech Consultants, Inc. (aka HTC). In the years that followed HTC became a premier process equipment and SWD plant design firm. In 2015 Bill transitioned HTC into Breakthrough Engenuity LLC with the motto: "*where engineering meets ingenuity*", to address some of the industrywide changes occurring in the 21st century.

Breakthrough Engenuity leads through innovation. Twenty-one related patents attest to its ingenuity. Breakthrough Engenuity is the "go-to" firm for 21st century oilfield facility designs.

As one of the industry's leading low-cost consulting engineering and facilities design firms, Breakthrough Engenuity offers the industry's most efficient high and low pressure, two and three-phase heated and unheated separators, complete processing facilities, as well as most other engineering services geared to specialty subjects like:

- Specialty vessel internals designed to maximize separation performance.
- Natural gas handling to optimize income and liquids recovery.
- The application optimization of oilfield chemicals geared to reduce cost and improve performance.
- Pipeline sizing to avoid turbulence, erosion-corrosion, and emulsion-causing mixing energies.
- 3D CAD modelling to facilitate timely facility installation and avoid unnecessary delays.

Now, more than ever, Breakthrough Engenuity can be found in every sector of the oil and gas industry, adding efficiency and cash flow and efficiency to upstream operations. Breakthrough is a full-service consulting engineering firm, and pledges to exceed each client's expectations.

CONTACT

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