

# **Recycle Options**

## **for the Management of Fracwater Flowback and Produced Water**

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### **Water Management Costs and Issues**

The typical means of managing produced water in many areas is by injection well disposal, often into the originating formation, but this option is not always available (Arthur 2008). Disposal options vary by state regulations and local conditions. When available nearby, injection is generally the most economical produced water disposal option (Veil 2004). Consider a hypothetical case of fracturing a gas shale at a new horizontal well. Figure 1 describes one very real way the water needs could be handled if onsite or local water and injection disposal are not available. Large volumes of water can be produced at some operating gas wells such as the Antrim and New Albany shales (Arthur 2008), but in our hypothetical case, let's assume there is little produced water from the gas shale normally, which is widely the case over several large gas plays, so the limited water disposal options are normally not a great problem. However, in our case there will have a flowback from 2.0 million gallons of "slickwater" frac fluid [AKA "fracwater"] that will need to be disposed of over a couple of months following the fracturing work.

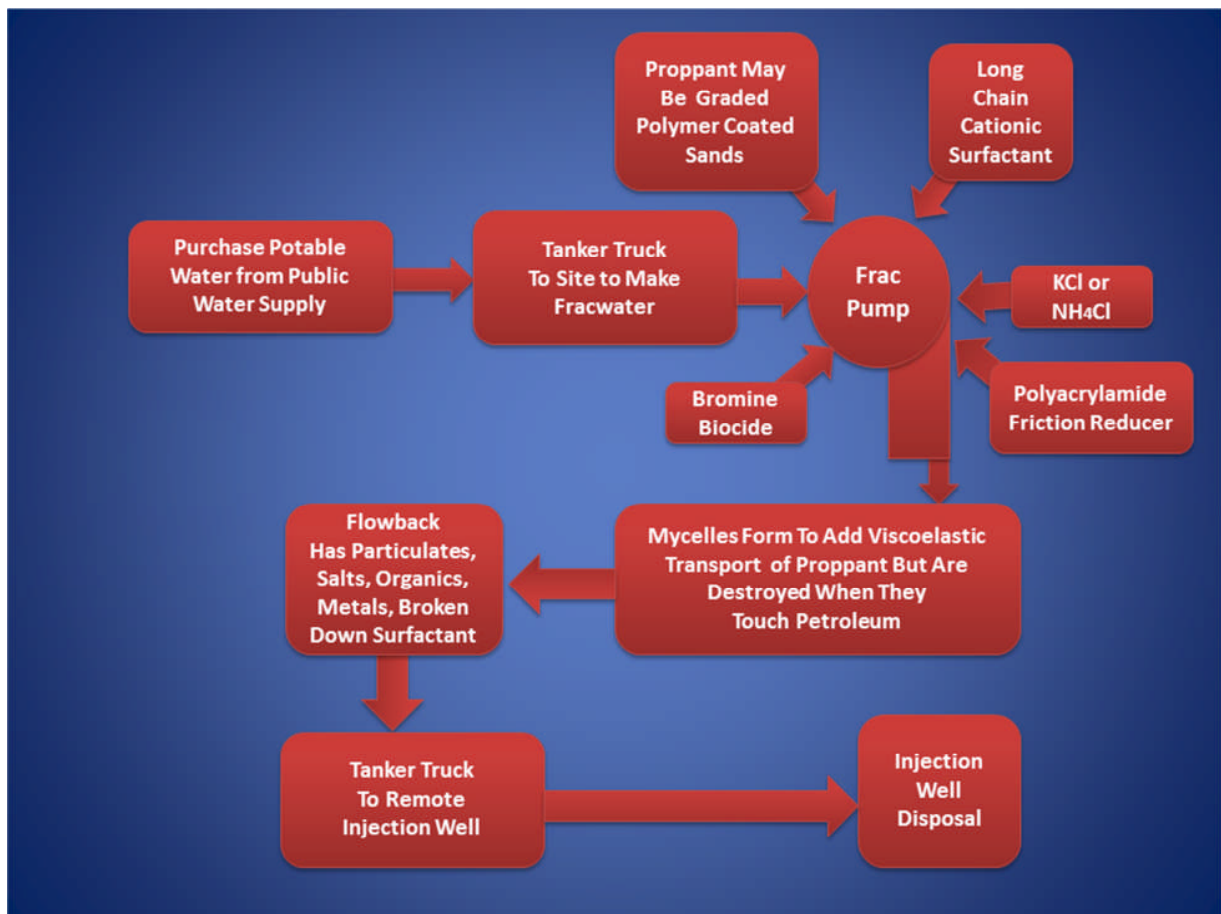
In this case, assume the water used for making fracwater can be obtained from a public water supply surface water source, so it is highly oxygenated potable water. There is no availability of water without trucking to the hypothetical site. A water truck might cost \$140 per hour for a 140 bbl capacity vacuum pump tanker. Assuming loading, driving full, unloading, and driving empty will consume two hours per round trip, the delivered water would cost \$2.00 / bbl, or \$48,000 to make up all the fracwater needed for the job. If the driver was going 30 miles each way, he might easily be burning about 10 gallons of fuel for a round trip. If the 2012 price of diesel is about \$3.85 at the pump, his fuel cost alone is almost \$40 of the \$280 total, or 14% based on these merely hypothetical yet realistic illustrative figures.

We expect that our flowback for this hypothetical case will contain some polymer coated sand proppant, clay particles, cationic surfactant, TPH with dissolved PAH and VOCs, polyacrylate, and salts including sodium chloride, potassium chloride, calcium sulfate and a little barite scale particulate. It is cleaner than typical produced water but no longer fresh water after its use. Everything in the flowback could be

injected into an approved disposal well, but the receiver well is a considerable distance away. The decision is made that the solids contents will be acceptable to inject and that there is nothing needed insofar as treatment to dispose of the flowback in this way, but the trucking cost will be \$3.00 / bbl injected, again due to the distance, time, labor, vacuum pumper tank truck, and diesel fuel. There are no municipal treatment plants nearby to offer an alternative to this trucking based disposition.

With a 70% expected flowback the disposal cost will be about \$100,000 to dispose by injection and will require 340 tanker truck trips. Realizing water plus flowback disposal cost will be close to \$150,000 for the job, flowback recycle by onsite treatment might be considered because it is expected that another 2 million gallons of water will be needed soon for a future frac job nearby. For some treatment schemes, we realize up front that sludge will be produced that could be landfarmed if allowed or could be injected into a well. Before injection of high solids we should consider the potential effect on the receiving formation's porosity and the possibility that acid treating of the injection well could be needed as a result of excessive sludge injection, resulting in additional cost (Lin 2007). Presumably the sludge could also be disposed of in this case as part of the cuttings and mud pit mud from drilling, landfarmed, spread on site, or whatever path is least expensive and approved for the area.

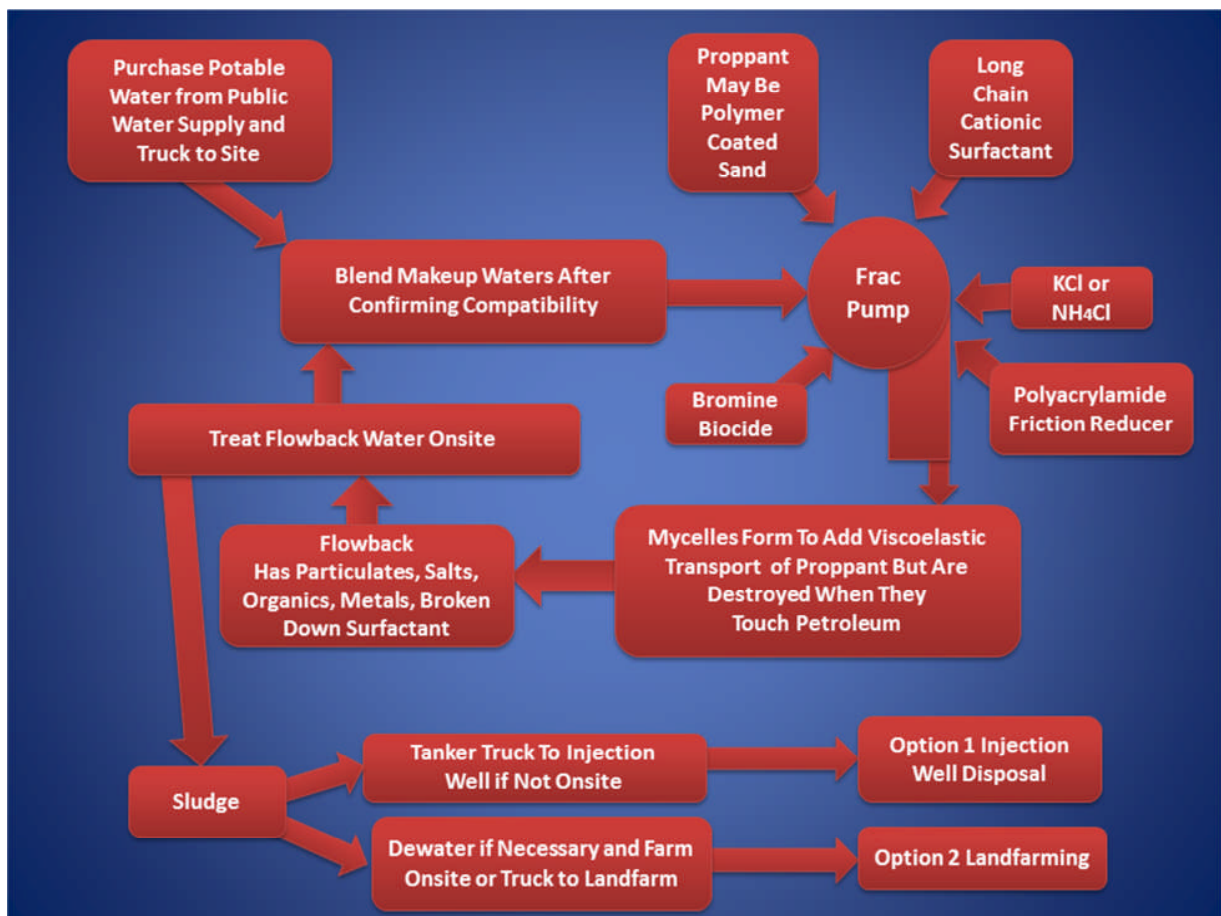
**Figure 1: Hypothetical Frac Job Approach**



It appears in this hypothetical case that if a suitable frac fluid makeup water can be produced and either piped or hauled to the next job for less than \$135,000 (minus the sludge disposal cost) then there will be a net savings from onsite water treatment. Treatment in this case just might be less expensive than buying all the new makeup water and paying for disposal of the old flowback. Obviously if injection was available nearby and well water was available onsite that was suitable to make new slickwater frac fluid, the economics in this hypothetical case would be quite different. Also note that we are making cost decisions based on using treated water for the next job nearby and *if there is* no next job, then remote disposal would be the only option.

Figure 2 illustrates a recycle option where a water treatment process is used on the flowback to produce an effluent candidate for use in makeup water at the new frac site, avoiding the need to buy as much water, but water from some source is still needed. We can assume the same source as before might be used.

**Figure 2: Water Recycle Alternative Frac Job Approach**



Some questions that might come to mind are what kind of treatment process might be considered and what will the effect of this treatment be on the performance of the new fracwater? Moreover, we might also ask whether in areas where typical deep brine produced water from oil wells is always readily available, what kind of treatment might make that kind of produced water also a candidate for making up fracwater and drilling water to use in that field? We might also ask whether we would be able to easily transport the selected treatment equipment between job sites and what would the costs be like if we always recycled produced water for drilling and fracwater makeup rather than going to outside sources. If treatment is clearly not economically viable, we need to know early on.

### **The Contents of Produced Water**

Before thinking more about these fine questions, if we are going to seriously consider turning produced water into fracwater and drilling water, we should take a quick look at what is in produced water to begin with. Working production sites might have a whole variety or combination of two or three phase oil gas water separators installed, operating at different pressures and temperatures. These offer some level of treatment that affects the produced water there. At new well sites there may be nothing beyond an open plastic-lined pit or steel tanks before completion.

Prior to the addition of production-enhancing chemistry, separated produced water from a reservoir formation is normally composed of brines with a petroleum component. As well production continues over time the oil:water ratio tends to steadily decline (Arthur 2002, Veil 2004). If fresh water was used as the chief frac fluid component in a frac job, as traditional, then the flowback may be salt water, brackish, or very near fresh but the concentrated salts typical of deep brines would not be expected early during a flowback collection that used freshwater-based frac fluid. Likewise, if freshwater alkaline flooding water from injection is being produced, then this will control the characteristics of produced water accordingly. A whole spectrum of chemicals might be present after chemical additions for enhanced production.

Residual oil is often stated as Total Petroleum Hydrocarbons (TPH). TPH is not well defined and says little about solubility or how much petroleum might be adsorbed on suspended solids. There is always some soluble fraction of oil dissolved in the brine itself rather than floating in a top layer or dispersed in droplets. Soluble organics include C<sub>2</sub>-C<sub>5</sub> carboxylic acids, ketones, and alcohols as well as propionic acid, acetone, and methanol (Veil 2004). Soluble oil was reported to 1,000 mg/l in produced water (Arnold 2008) and has been reported by other sources as up to 5,000 ppm (Veil 2004). Produced water contains polycyclic aromatic hydrocarbons (PAHs), phenols, and volatile organics as well as organic acids (Veil 2004).

While TPH can include up to hundreds of compounds that vary strongly between reservoirs, disproportionate attention has been devoted to benzene, toluene, ethyl benzene, and xylene (BTEX) for their pervasive presence as a group and due to the carcinogenic classification of benzene, and less attention to the standard reference compounds hexane, naphthalene, fluorene, and kerosene. Partially soluble C<sub>6</sub> to C<sub>15</sub> hydrocarbons are difficult to remove from water and are a problem if discharged due to their toxicity, carcinogenicity, mutagenicity, and other highly undesirable biological features (Veil 2004). Just as the TPH components vary greatly in natural brines, the natural brines themselves vary greatly between reservoirs as to the chemistry of their other components. Dissolved gases can include methane, ethane, propane, butane, hydrogen sulfide, and carbon dioxide. Produced water from gas condensate is typically higher in soluble organics than from most oil wells. Water from glycol regeneration vapor

recovery systems contains higher BTEX concentrations than other produced water (Lin 2007). While the variation may seem bewildering, no apparent reason prevents using water with most of the characteristics of natural brines with some dissolved TPH as fracwater so long as the compatible additives are chosen (Bryant 2010).

Dissolved solids in produced water typically range from 100 mg/l to 300,000 mg/l, with clean gas-only formations on the low side and “hot” high temperature oil formations on the high side. In our hypothetical case above, we might expect the low range of dissolved solids. Brines from an oil reservoir will have  $\text{Na}^+$  and  $\text{Cl}^-$  ions in dominant concentrations, but some  $\text{Ca}^{2+}$ ,  $\text{Mg}^{2+}$ , and  $\text{Fe}^{2+}$  will normally be present, and to a lesser extent  $\text{Ba}^{2+}$ ,  $\text{K}^+$ ,  $\text{Sr}^{2+}$ ,  $\text{Al}^{3+}$ ,  $\text{Li}^+$ . Anions are often  $(\text{HCO}_3)^-$ ,  $(\text{CO}_3)^{2-}$ , and  $(\text{SO}_4)^{2-}$  (Lin 2007). Precipitants and scales are frequently  $\text{BaSO}_4$  (Crabtree 1999) or  $\text{CaCO}_3$ ,  $\text{CaSO}_4$ , and  $\text{FeS}_2$  (Lin 2007). Scale inhibitors that can be present in produced water include inorganic phosphates, organic phosphate esters, phosphates, and polymers (Lin 2007). Polyacrylate is a popular scale inhibiting polymer (Chilanger 2008). Polyacrylic acids of molecular weight 200 to 5000 have shown good friction reduction antiscale performance in some waters. With high TDS brines a custom formulation is the best choice (Bryant 2010).

Researchers at the Oak Ridge National Laboratory tested the effect of pH on TPH solubility by adding brine simulants to a standard crude. Analyses using this standard produced water indicated that formic, propionic, and acetic acid are ubiquitously present in the soluble fraction, with acetic acid as the dominant species of these organic acids, typically at concentrations of 10-30 ppm (Bostick 2002). When a brine simulant was introduced that raised the unenhanced produced water pH, the TPH dissolved in the water fraction increased, suggesting a direct correlation between TPH solubility in produced water and the water’s pH. In the dispersed droplet form, the intensity of dispersion of oil in alkaline water having less divalent cations is far greater than in “hard” water (Chilanger, 2008). This phenomenon results in the favored use of alkaline water for flooding in enhanced recovery (Speight 2009).

In fracwater flowback and in water produced from cold recovery-enhancement workovers, the produced water chemistry will vary widely according to what has been intentionally added for process reasons. Examples of cold recovery well enhancement include alkaline flooding, alkali-surfactant-polymer (ASP) and micellar polymer (Speight 2009). Frac fluid flowback may at times include nitrogen and carbon dioxide used as pressure drivers in foams, with nitrogen used more alone in shallow well recoveries and carbon dioxide more in deeper wells, or combinations of both gases.

Although micelle forming surfactants have received attention, guar gum, hydroxypropyl guar, (HPG) or carboxymethylhydroxypropyl guar (CMHPG), all AKA “slick water” guar thickened frac fluids, still remain popular for some deep frac jobs. Viscosity can be tuned with these slick-water guar and guar-derivative fluids, sometimes crosslinked and sometimes not, to ensure pressure and good proppant delivery deep into the fractures (Lyons 2005, Schein 2006). The idea is to adjust viscosity and keep it low enough to pump through tubes without excess pressure loss yet high enough to cause large fractures while transporting the proppant fully into them (Lyons 2005).

This need for this viscosity-based balancing act and their desirable conductivity and permeability qualities has at times caused low density proppants such as epoxy-impregnated walnut hulls to be selected rather than sand. Epoxy impregnated walnut hulls in a Barnett Shale used with slick water frac fluid had 86% flow back recovered in 60 days while a nearby well fraced with slick-water and conventional sand

proppant had 51% flowback recovered in the same 60 day period (Schein 2006). The fraction of recovered flowback is an indicator of the success of a frac job, but the more important indicator is of course the subsequent petroleum production rate.

For frac proppant delivery, long chained linear alkylated ( $C_{18} - C_{22}$ ) cationic surfactants capable of forming wormlike micelles in the presence of inorganic salts such as KCl,  $NH_4Cl$ , or salicylates have also successfully been employed to deliver proppant. At less than 0.5 wt% solutions, micellar viscoelastic structures form when the inorganic salts contact the cationic surfactants and having performed their proppant delivery function, the viscoelastic structures break down instantly upon contact with hydrocarbons, leaving only conventional surfactant molecules. This means the frac fluid will not plug any channels or reduce porosity and recovery should be high (Rosen 2000). Some surfactants used in well development will thermally degrade while others will not (Ash 2008).

Produced water following cold enhanced recovery workovers can include any of hundreds of additives for many functions. A few examples not previously mentioned are alkaline surfactants, bases like sodium hydroxide, acids such as hydrochloric and phosphoric acids, a wide variety of polymers, N-Butanol and  $C_4$  alcohols, glycerol, and ethylene glycol (Fink 2003). Of course care is taken to avoid in situ reactions that could do more harm than good when attempting to enhance production. Injection of a poor choice of water can likewise induce disastrous scale precipitation as a reaction front moves through the reservoir rock (Crabtree 1999). This creates concern about the quality of water selected for frac fluid makeup (Bryant 2010).

### **Design Criteria for Recycle of Fracwater and Produced Water**

In selecting what sort of treatment process is appropriate to recycle fracwater or produced water for drilling and fracwater makeup, capital equipment cost, operating and maintenance cost, capacity, performance, footprint, portability, robustness, and the ability to operate over wide ranging parameters should be considered. Produced water will vary broadly in characteristics because of the source of the water (injected potable vs. well vs. recycled brine), because of natural variations in the reservoir fluids, and because of the additives--additives which are likely to continue to evolve based on new information and experience. Therefore flexibility and resistance to upsets is quite important to selecting a process capable of producing a predictable result.

Unfortunately, specific quantitative criteria for frac fluid makeup water may be difficult to find, and thus the effluent requirements for selecting treatment equipment, seem hard to define with any precision. It is known that water recycled with high divalent cations could pose precipitation and scaling issues, so as long as we are treating anyway, reduction of these would always be desirable. Some researchers have suggested that high TDS brines with little or no treatment might be recycled as frac fluid so long as careful experiments are used to select the correct friction reducer and to control scale formation with additives (Bryant 2010). The design of the frac fluid should be tailored to the makeup water no matter what the source of the makeup water is.

When we look for basic design criteria we find the following to be obvious:

- The makeup water should have fluid properties conducive to providing the pressure needed to propagate fractures. (*All* water appears to meet this).
- The makeup water should work together with the viscosity controller (guar-based or surfactant-based slick) to transport the proppant correctly. (This should be based on testing).
- The slick makeup water should be compatible with other makeup water it is blended with whenever we have to get water from multiple sources. (This should be verified by experiment).
- The chemistry of the makeup water should not encourage scaling in the pipes or in the reservoir. (This should be based on the presence of divalent cations, sulfate, iron, and carbonate content and on adequate testing during the selection of friction reducers and scale controllers, so the treatment should remove divalent cations present to low levels, especially  $Ba^{2+}$ ,  $Mg^{2+}$ ,  $Ca^{2+}$ , and  $Fe^{2+}$  and remove some carbonate and sulfate anions as well.) While no limits are stated here, if the process isn't reducing these to low levels, another process should be considered.

## Treatment Units

Table 1 below summarizes some of the common treatment units that can be used alone or in various combinations. These are merely illustrative and by no means is this list exhaustive. Their functions and applicability are considered below.

**Phase separators** of some type are permanent installations at many oil production facilities and some gas production facilities. They may or may not have moving parts. The more elaborate internals increase the capital cost while decreasing the footprint. They operate at a spectrum of temperatures and pressures and are very low in operation and maintenance cost. Capital cost increases with wall thickness or alloy for the high pressure variants. To remove the final oil from mostly water, the low pressure API Standard Oil Water separator is a slanted plate clarifier with bottom sludge cone discharge and top skimmer. In some cases it may be undesirable to allow produced brine that will be reinjected in the reservoir to come into contact with open air because the corrosivity will increase with the introduction of dissolved oxygen, so a sealed containment is employed. Hydrophilic fibers can encourage oil drop agglomeration and improve downstream contact surface performance. Centrifuges are by far the highest efficiency separators but have high speed moving parts. A mobile separator unit could be skid mounted, trailer mounted or truck mounted. They can be structurally robust. A phase separator alone will remove most of the floating oil and settling solids like proppant and scale particles, but it will not remove dissolved organics or dissolved solids or change the water chemistry very much. Dissolved Air Flotation can boost the oil removal efficiency.

**Chemical treatment** is the traditional industrial waste water treatment that usually employs metal salts such as aluminum chloride, ferric chloride, ferrous chloride, and ferrous sulfate and polymers such as polyacrylamide, which is coincidentally sometimes used as a "friction reducer" increasing flow during frac jobs. Suspended solids are removed by the agglomeration of charged floc that is floated and skimmed, settled and discharged from a cone bottom, or both. By placing a static or tank impeller mixer upstream, an API oil water separator can be employed as the clarifier. Staged mixers are sometimes placed in a fast to slow mixing series to grow bigger floc without floc shearing by the mixer. Salts and polymers are usually selected by jar testing and then injected upstream of the clarifier (plate separator or DAF) via

metering pumps. High pH or sodium sulfide can be used to precipitate metals prior to floccing, after which pH adjustment will be required. The loading of chemicals is very sensitive to the wastewater parameters.

**Table 1: Some Common Treatment Units**

<b>Phase Separators</b>	API Standard
	Dissolved Air Flotation
	Plate Coalescers
	Oleophilic Fiber Bundles Followed by Cross Flow Plate Separator
	Liquid/Liquid Hydrocyclone
	Centrifuge
	Vertical or Horizontal Skimmer with Corrugated Plate Interceptor
<b>Chemical Treatment</b>	Salt Polymer Mixer With Plate Separator
	Salt Polymer Mixer With Plate Separator and Particulate Recycle
	Salt Polymer Mixer With Plate Separator, Particulate Recycle, and pH Control
<b>Ion Exchangers</b>	Resin Beds
<b>Granular Filters</b>	Backwashable Beds
<b>Ultrafiltration, Reverse Osmosis membranes, Nanofiltration and Hyperfiltration Tube Bundles</b>	Mechanical Micro to HyperFilter
	Mechanical Filter with Cyclone
	Mechanical Filter with Cyclone and Mechanical Prefilters
<b>Electrocoagulation</b>	Granule, Tube, Rod, or Offset Plate Electrode Designs

The chemical treatment regime will be somewhat unique to each wastewater, so new tests are needed whenever wastewater characteristics change. Chemical treatment can produce a much higher clarity water than the phase separator alone, and also has a much higher operating and maintenance cost, with higher labor as well as chemical cost. Some propose this (always including clarification and at times polishing filtration) as the most appropriate treatment for recycle of flowback (Manz 2011). This author's experience in designing, building, and employing these units to pretreat industrial wastewater in the past is that their performance can be very sensitive to changes in the wastewater, especially pH and TDS, so that constant oversight is needed to produce consistent results for any variability in the wastewater. Chemicals can be expensive as well.

This sensitivity to incoming parameters has been recognized by others, as well as the difficulty of producing floc in all cases and controlling the tendency for high TDS of the effluent, so pH control can be added up front as well as a microsand feeder recycle loop that enhances the formation and settling of the floc by providing a constant loading of substrate to settle. These enhancements increase performance but also increase chemical and material cost as well as operating complexity. Chemical treatment sludge can be fragile and difficult to dewater and separate. It can be voluminous and cling tenaciously to its water at times. Nondewatered chemical sludge could be easy to inject into wells, but its behavior in the receiving formations seems uncertain.

**Ion Exchangers** are expensive to operate, and may require oil removal upstream of them to low TPH levels. Hydrogen based exchangers effective for brines will require strong acid regeneration. Ion exchange should be considered if extended electrocoagulation cannot be tailored to result in low hardness product. Spent media may pose disposal issues, especially when very high in radium.

**Granular Filters** are sometimes used to polish phase separator discharge of the carry over solids. These are merely competitors of mechanical bag or cartridge filters that eliminate the changeout of bags or cartridges while requiring backwash that at times can be problematic. These are often employed to polish chemical treatment effluent.

**Reverse Osmosis Membranes** have proven effective in removal of a wide variety of substances from water, including organics. The size molecule that is captured can be tailored by the selection of filter media rated in micron ranges. Phase separators, cyclone settlers, centrifuges, or some type of fine size mechanical prefilters upstream of the membrane would be needed for most concentrated produced waters. While a reverse osmosis or tube bundle hyperfilter is small, the upstream prefiltrations adds to the footprint, but a unit capable of treating our jobsite produced water could be easily trailer mounted including some upstream helper units to pretreat.

A negative feature of membranes is the possibility of irreversible fouling of the expensive membrane media. Obviously hardness scaling would be a problem with some waters, but colloids ubiquitous in nature have been shown to irreversibly foul some reverse osmosis (RO) membranes (Wang 2008). While membranes can effectively remove petroleum derived hydrocarbons, if chemical cleaners are unsuccessful then the expensive media must be replaced as the only choice (Cheremisinoff 1998). In spite of this, nanofilter tube bundles and RO membranes have been successfully used to treat produced water in the past on offshore platforms (Veil 2004). New polymer surface charge designs are intended to reduce fouling. If a very high quality product is required for some reason, then a possibility would be to run RO downstream of either chemical treatment or electrocoagulation. This type of treatment, along

with the media fouling risk and cost, appears to be an unnecessary level of treatment in order to produce water sufficient for fracwater makeup or for drilling.

**Electrocoagulation** is a century old and was embraced early by the mining industry. This is a tolerant robust competitor of chemical treatment. These units are small footprint and high efficiency. It is effective in removal of emulsified oil, TPH (at least the heavier components), suspended solids, and heavy metals. The surface charge that holds emulsions and particles in suspension is disrupted by the presence of an electrolyte having the opposite charge. The coagulant is generated by electrolytic oxidation of an anode material, usually aluminum, iron, or graphite. Charged ions are removed from the water by reacting either with an ion having an opposite charge, or with floc of metallic hydroxides generated within the water. Metals precipitate as hydroxides. The reaction and generation of floc occurs quickly as the water is passed between the charged electrodes, and the floc can then be removed by the standard clarifier design of skimming the floating layer and burping the settling cone, although the plate separator size can be smaller because the floc quality is better with electrocoagulation than with chemical treatment. Because of the small footprint, simplicity of operation, and performance against a wide range of variable parameters, electrocoagulation appears to be the preferred treatment choice for our case.

**The favored technology** is discussed in greater detail below. Electrocoagulation operation is less sensitive to changes in the incoming wastewater than chemical treatment operation. Power cost may be significant for some designs, depending on the geometry and how the electrodes are spaced, but there is no chemical cost other than electrode replacement. Offset plate designs can have alternating charge on each plate and typically a 0.5" to 2.0" spacing (Noyes 1994). The anodes are gradually sacrificed by becoming ions in solution as some of the water undergoes electrolysis or hydrolysis.

While there is dissolution of metal from the sacrificial anode there is simultaneous formation of hydroxyl ions and there is simultaneously hydrogen gas coming off the passivated cathode (Holt 1999). The anode is the source of coagulation while the bubbles of hydrogen come from the cathode and to a lesser extent some bubbles of chlorine (EPA 1998). Gas bubbles generated at the cathode act to buoy up the floating fraction of destabilized agglomerating waste. Bubble size is largely determined by electrode spacing and electrical current (Malakootian 2009). Some designs offer adjustable spacing and others do not. A filter press for solids downstream of the clarifier can be considered depending on what sludge disposition path applies.

Like ions, colloids have also been shown to migrate toward charged anodes suspended in water (Mohammed 1998). Electrocoagulation is not likely to remove the very light hydrocarbon component sure to be present in produced water and fracwater flowback. Some designs showed poor removal of methane, ethanol, benzene, toluene, etc. (EPA 1998) but there is no reason this removal would be required for production of fracwater makeup. Divalent cations are removed that cause hardness and scaling (Malakootian 2009, Halliburton 2012, Oil Trap 2012). Radium, when present, is likely to be removed to the sludge, which would be true of several competitor technologies as well, and to a lesser extent, uranium was removed during treatment demonstrations (EPA 1998), so NORM could be concentrated in the sludge and possibly on the electrodes in some cases.

It is not clear from the literature examined to what extent electrodes can be damaged by precipitant and scaling that could reduce conductivity, and thus effectiveness, if there is sufficient divalent cation hardness in the treated stream. Depending on the design and electrode spacing, frequent cleaning of

electrodes may be required when treating some wastewaters (EPA 1998). Efficiency for hardness and TDS when not determined by the clarifier downstream appears to be a function of the electrode spacing (more space removes more divalent cations and uses more electricity and needs higher voltage applied) and by pH. It appears that the highest divalent cation removal efficiency could be achieved by adjusting the incoming pH to 10.1 with sodium hydroxide based on hard water testing (Malakootian 2009).

Electrode replacement due to scaling or sacrificial thinning and energy costs are expenses to consider but electrocoagulation probably offers the best overall mobile unit process available for field treating produced water or fracwater flowback. Some designs allow electrodes to be easily and quickly replaced, and alternating sections or trains can permit full time operation during electrode replacement and cleaning.

Over the past century many electrocoagulation designs have been experimented with, such as submerged rods, tubes within tubes, flat plates, and fluidized beds of small particles, while electrical supplies have included high and low voltage AC and DC currents, high frequencies, square waves, and exotic waveforms. Nevertheless, the Kaselco units manufactured today use simple flat plates and low voltage DC current very similar to the original century-old first design ever used (Kaselco 2012). Plates, tubes and rods are currently very popular, as well as a whole range of voltages. Some of the larger capacity electrocoagulation systems can use fairly high voltage power (Powell 2012). As with most treatment technologies, many people suggest testing to verify results of a particular design for a particular wastewater (Holt 1999, Kaselco 2012). As soon as some of the water to be treated can be made available, testing is what can provide confidence that the results of a chosen treatment will be a good product for fracwater makeup. This is no less true for a new untried offsite source of makeup water.

Cost of Electrocoagulation is inexpensive based on easily found reports and current advertisement. Some manufacturers who advertise oil field services also state average electrocoagulation treatment costs as low as \$2 to \$5 per thousand gallons treated (Oiltrap 2012). A 1998 study arrived at \$3 to \$9 (1995 USD) per thousand gallons to pump and treat groundwater for metals removal (EPA 1998). Makeup water trucking costs alone could never compete with these kind of treatment cost numbers, but these are likely to be based on operating costs for continuous long term operation of installed systems, not for temporary deployment and brief operation of mobile units in remote locations typical of well sites.

Treatment centered around this process shows enough promise that some investors are advertising plans to build centralized oil field produced water processing facilities based on electrocoagulation very soon (USI 2012). Other companies are offering electrocoagulation mobile units for temporary onsite treatment (Halliburton 2012). The latter mobile unit specification indicates that it can treat up to 20 bbl/min of fracwater flowback with 150 kVA / 120 kW electrical requirements, and the supplier advertises that it is intended to treat produced and flow back water to a standard suitable for reuse *in fracturing* or drilling fluids. Literature review indicates that achieving this goal is a very real possibility.

### **Is this Real?**

The viability of treating produced water or frac flowback, even when the next alternative involves lots of expensive trucking, is difficult to gage. There are claims of great success and failure and this author doesn't have all the inside details of what went right and what went wrong. Here are some examples:

The Railroad Commission of Texas (RRCT 2012) reports that:

- Fountain Quail Water Management treats fracwater flowback by distillation using the gas from the fractured Barnett Shale formation with over 12.7 million bbls of returned fracture fluid resulting in 9.9 million bbls of reusable distilled water for frac jobs. Based on this, a new distillation facility is being developed that will initially process 7,000 bbls per day of fracwater flowback and an additional 7,000 bbls per day of produced water and will have a capacity to double that rate later.
- DTE Gas Resources, Inc. conducted a pilot project for treatment and reuse of fracwater flowback with onsite separation and filtration. [Whether chemical treatment was employed is implied but not reported.] On November 13, 2007, DTE Gas Resources reported that the pilot project had ended because it was economically nonviable.
- Devon Energy Production Company, treated fracwater flowback by separation and filtration [Whether chemical treatment was employed is implied but not reported.]. On October 22, 2007, Devon reported that the pilot project had ended with no recycled water reused. Devon then tried a different vendor to treat fracwater flowback and produced water and abandoned this pilot project in October 2008 reporting no success in producing reuseable treated water.

Contrast those results with:

- Halliburton used electrocoagulation [additional filtration, if used for polishing, was not reported] to treat 55,000 bbls of fracwater flowback having >50,000 ppm TDS in under four days eliminating 1,000 tanker truck trips and 5,000 hours of drive time at a savings exceeding 0.25 million USD (Haliburton 2012).

Well in the case of Fountain Quail, obviously distilled water is going to be acceptable to even the most demanding connoisseur of frac makeup, but distillation isn't normally an economically competitive treatment process. That's why it isn't even listed at all as a typical process in Table 1. The gas was cheap and readily available, and the author here has no idea what it would have sold for had it not been used for distillation purposes. The economics appear to work for that case.

Likewise, we have no information as to what about Devon Energy's treated pilot plant effluent made it unacceptable for use as fracwater makeup, or what components made DTE Gas Resources' treatment cost too expensive. Halliburton looks like the clear winner among the nondistillation attempts above.

## **Conclusions**

This is a best guess about what seems likely from reviewing words on paper and computer screens. You can't treat wastewater on paper or with computers alone. You have to treat real flows with full scale equipment before you can be positive of anything, and then tomorrow may be different and it may not work exactly the same on the next wastewater down the road. Keeping that in mind, based on a literature review combined with the author's real experience with the competing alternatives of chemical treatment, phase separators, membranes, granular filtration, carbon filtration, mechanical filtration with cartridges, bags, microscreens, etched metal, and ion exchange resins, and various combinations, electrocoagulation

appears to hold the most promise for recycle treatment of fracwater flowback and produced water, including water modified by cold enhancement chemistry, whether using mobile equipment or at a centralized area fixed facility.

The effluent of electrocoagulation could be polished by granular or mechanical filters if desired, but this probably isn't necessary, depending on your requirements for fracwater makeup and drilling water. The elimination of trucking costs and some of the social impact of truck traffic by using mobile treatment units is a very appealing feature of recycling fracwater flowback or produced water for frac fluid makeup.

Given the tremendous variability of produced and recovery-enhanced produced water, testing of the process should be performed before investment in electrocoagulation or any other process.

If treatment is elected, testing of the treated water should be performed to confirm that a good choice of friction reducer that works well with the recycled water will be employed. Because produced waters, especially from some cold recovery enhancements can vary so widely in their chemistry, the treated water to be recycled should also be analyzed to see what constituents have been removed by the electrocoagulation and what constituents may remain before finalizing the choice of fracwater additives.

Mixing the electrocoagulation-treated water with the makeup water from other sources should also be evaluated by experiment to confirm compatibility before proceeding with blending.

The economics of recycle are obviously driven by the availability of nearby or onsite makeup water and disposal injection wells. As shown in the hypothetical example using realistic costs, under some conditions, high trucking costs can result in the need for evaluation of water treatment and recycle options.

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