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Hydraulic Fracturing 101: What Every Representative, Environmentalist, Regulator, Reporter, Investor, University Researcher, Neighbor and Engineer Should Know About Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells.

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Abstract

Identification of risk, the potential for occurrence of an event and impact of that event, is the first step in improving a process by ranking risk elements and controlling potential harm from occurrence of a detrimental event. Hydraulic Fracturing has become a hot environmental discussion topic and a target of media articles and University studies during development of gas shales near populated areas. The furor over fracturing and frac waste disposal was largely driven by lack of chemical disclosure and the pre-2008 laws of some states.

The spectacular increase in North American natural gas reserves created by shale gas development makes shale gas a disruptive technology, threatening profitability and continued development of other energy sources. Introduction of such a disruptive force as shale gas will invariably draw resistance, both monetary and political, to attack the disruptive source, or its enabler; hydraulic fracturing.

Some “anti-frac” charges in media articles and university studies are based in fact and require a state-by-state focused improvement of well design specific for geology of the area and oversight of overall well development. Other articles have demonstrated either a severe misunderstanding or an intentional misstatement of well development processes, apparently to attack the disruptive source.

Transparency requires cooperation from all sides in the debate. To enable more transparency on the oil and gas side, both to assist in the understanding of oil and gas activities and to set a foundation for rational discussion of fracturing risks, a detailed explanation of well development activities is offered in this paper, from well construction to production, written at a level of general public understanding, along with an initial estimation of frac risk and alternatives to reduce the risk, documented by literature and case histories. This discussion is a starting point for the well development descriptions and risk evaluation discussions, not an ending point.

Introduction to Risk

There are no human endeavors without risk. “Risk management is the identification, assessment and prioritization of risks followed by coordinated and economical application of resources to minimize, monitor and control probability and/or impact of unfortunate effects” (Wikipedia). At a minimum, basic risk concerns are: People, Economic Loss (to all concerned), Environmental Damage and Reputation Loss. Figure 1, a standard loss matrix used by Apache Canada in the Horn River development (DeMong, 2010), is a good starting place for the discussion. Consequences run from slight and practically unavoidable to severe and avoidable at all costs. This paper, for purposes of brevity, will focus solely on risk to the environment from hydraulic fracturing operations,

starting with transport of materials and ending when the well is routed to the production facilities and gas sales begin. The form of Figure 1 will be expanded and comments and descriptions of problems that begin with drilling, well construction and production will be discussed, but their risk assessment is in a separate category.

Figure 1

Hazard Identification & Control

Consequence					1	2	3	4	5
					Probability				
	People	Loss	Environment	Reputation	Never Heard of in Industry	Heard of in Industry	Occurred in our company	Occurs several Times /yr in our company	Occurs several times per yr in location
1	Slight Injury	Slight Damage	Slight Effect	Slight Impact					
2	Minor Injury	Minor Damage	Minor Effect	Limited Impact					
3	Major Injury	Localized Damage	Localized Effect	Considerable Impact					
4	Single Fatality	Major Damage	Major Effect	Major National					
5	Multiple Fatalities	Extensive Damage	Massive Effect	Major International					

The consequences are those of credible scenarios (taking the prevailing circumstances into consideration) that can develop from the release of a hazard. The potential consequences, rather than actual ones are used.

DeMong, SPE 138026, 2010

The Probability is the estimated probability of the estimated potential consequences occurring.

	Extreme Risk- Cannot tolerate; immediate shutdown or measures to reduce risk required
	High Risk- Unacceptable for long term, must implement risk controls
	Moderate Risk- Evaluate risk reduction measures Changes may be necessary.
	Low Risk- No mitigation required

Many well development problems are blamed on fracturing, but have nothing to do with the fracturing process. Some of these excluded problems are real and are definitely worthy of inclusion in the discussion, to help define the boundaries of the fracturing risk and as a starting point for further understanding and work.

The initial assumption for the risk matrix is that the well is new and was constructed correctly (to design requirements) so that all producible formations are securely isolated behind the barriers of casing (pipe) and competent cement. No assessment of fracturing risk is made here for wells outside of the design requirements. The justification for this assumption is that the vast majority of fracturing is the first major stimulation in a well and occurs immediately after completing a new well. If an older well is re-fractured, then an assessment of well integrity and a separate risk analysis would be required.

Introduction to Fracturing

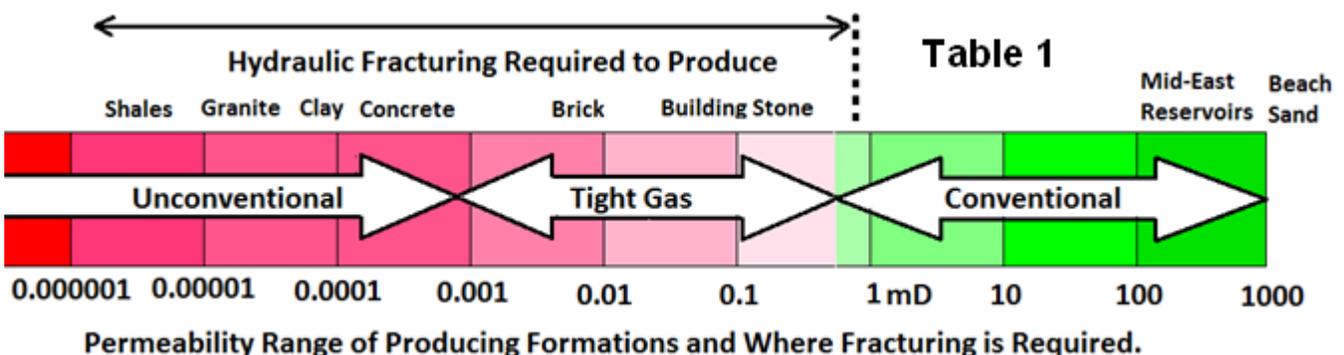
Hydraulic fracturing and horizontal wells are not new tools for the oil and gas industry. The first fracturing experiment was in 1947 and the process was accepted as commercial by 1950. The first horizontal well was in the 1930's and horizontal wells were common by the late 1970's. Millions of fracs have been pumped (Society of Petroleum Engineers estimate 2.5 million fracs world-wide and over 1 million in the US) and tens of thousands of horizontal wells have been drilled over the past 60 years. Even shale gas, especially from the Devonian shales (including Marcellus), are not new producing intervals. Devonian shales are the source rocks for the shallow oil wells of eastern Pennsylvania, where Mr. Drake drilled the first US oil well after noticing a number of natural seeps of oil and gas in the area. Concentrated shale fracturing research was kicked off by a Department of Energy (DOE) grant in the 1970's. Earlier forays include the first shale gas well in 1821 in Fredonia, New York, and archeological data on gathering of oil and tar from natural seeps by North American native inhabitants going back over 1500 years.

The technical literature around the “adaptation” of horizontal wells and hydraulic fracturing to shale developments is extensive, addressing nearly every aspect of shale gas and oil development with over 550 papers in shale fracturing and 3,000 on all aspects of horizontal wells. These publically presented and peer reviewed technical papers are from contributors covering 30+ years of shale technology development. The shale papers in the past three years alone are from over 70 universities, 4 US national labs, over a dozen state, federal and international agencies and more than a hundred energy and service companies. The references presented here are a very small part of the 60,000 industry and academia papers and studies available on oil and gas operations. A historical review of shale gas fracturing “Thirty Years of Gas Shale Fracturing: What Have We Learned” was presented in 2010, that reviewed 270 literature sources, focusing on the critical papers of shale development (King, 2010). Many other technical resources are available from universities, government, industry and study groups (Arthur, 2009; Engelder, 2008; Cramer, 2008; Lash; Modern, 2009; Zammerilli, 1989; Yost, 1989; Sumi, 2008; Soeder, 2008; Suarez-Riveria, 2009; Milici, 2005; Perkins, 2008).

For purposes of this paper, the components of well development, i.e., from seismic evaluation to production, are explained with intent to educate using basic descriptions and information on each step. Problem areas are purposely identified, not to vilify or glorify, but to help the public understand the risks and the steps that can be taken to reduce those risks.

In any risk matrix, local conditions will influence the conclusions. For regional or area studies, the impact and the occurrence information, from traffic accidents to well incidents should be from the area, but wider studies of other factors may be necessary for purposes of well population and incident review. There are over 840,000 oil and gas wells in the US (EIA, 2009) and a world-wide well count of approaching 1.2 million, but in a given field or even a small basin, the well population may not be sufficient for reasonably accuracy in risk estimates. Estimating risk at both regional and area levels allows identification of risk areas and refinement of that risk through knowledge of local conditions. Different companies operating in different areas of the country may use the same risk estimation approach but reach different values due to differences in roads, well construction requirements, infrastructure, engineering experience, local geology, regulations and other factors.

The gas and oil containing “shales” featured in this paper are classified as shales on the basis of the size of the very fine particles or grains that make up the rock. They are actually very fine grained sandstones, often with similar mechanical properties to the sandstones that comprise conventional gas and oil producing reservoirs. The difference is that conventional sandstones may have permeabilities in the range of 0.5 to 20 millidarcies (abbreviated as “md”), while these gas shales may have permeabilities of 0.000001 to over 0.0001 md (or 1 to over 100 nanodarcies). Permeability is a measurement of the ease of flow of fluids through the rock and a typical shale gas reservoir with a permeability of 100 nanodarcies has a permeability of 1/1000 of 1% of the permeability of a conventional reservoir with 10 millidarcy permeability. Fluid flow is much easier in materials with higher permeability. For reference, beach sand is roughly 2000 md, construction-grade cement averages about 0.005 md and shales vary from about 0.000001 to 0.0001 (Table 1). Not every shale has sufficient permeability to produce gas, even with the assistance of hydraulic fracturing.



Permeabilities are measured in the matrix or porous part of the rock. Gas and oil productive shales have natural fractures and micro-fissures, a characteristic missing from high-clay content shales that serve as natural seals

and barriers (with permeabilities so low they approach the permeability of steel pipe). Natural barriers are the rock seals that have held the gas, oil, and salt water in the reservoir for millions of years.

Bridging the Language Barrier

Environmentalists insist that some “fracks” have contaminated ground and surface waters while engineers insist that not one frac has ever contaminated ground waters; thus, there seems to be a wide disparity in accuracy of the statements. Surprisingly, both sides have valid arguments – just a mismatch of definitions. Much of the turmoil concerns how each group defines fracturing. In engineering terms, fracturing concerns a precise stimulation activity, limited to the fluid action in initiating and extending cracks in the rock; while, for many concerned citizens, bloggers and environmentalists, fracturing has come to represent nearly every phase of the well development cycle from drilling to production.

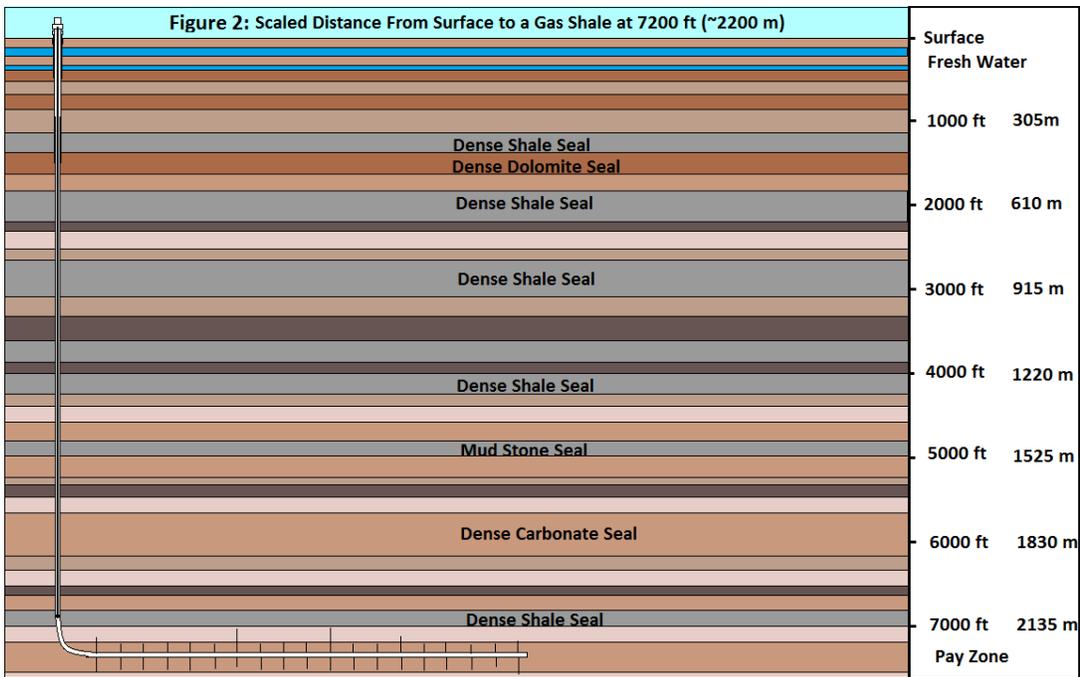
Accuracy in any argument rests on defining the subject; in this case it is activities in gas or oil resource development. The science behind well development activities, including fracturing, resides in about sixty thousand presented papers and peer-reviewed papers in the literature from a dozen or more engineering and geoscience societies, representing a hundred thousand engineers and scientists in the oil and gas industry, world-wide. The following are general descriptions of the steps in the well development process. More detail on specific areas related to improving regulations, pollution control and general understanding of disputed processes will be developed later.

First, scale drawings of the distance from the surface and near-surface fresh water supplies (nearly all fresh water formations are within the first 1000 feet or 305 meters from the surface) are needed to show the physical distance between the surface and the completion interval of interest (called the pay zone). Figure 2 illustrates the separation of the pay zone from the surface for a typical shale depth of 7000 ft (2130 m).

Fracture height predicted by computer models and confirmed by micro-seismic monitoring during fracturing, post-frac tracer flows, temperature logs and even mine-back experiments (Warpinski, 1985), show most vertical effective fracture growth at 300 ft (90 m) or less. Frac height growth in most formations is known to be effectively limited by barriers and leak off (loss of fluid to the rock). Frac heights limited by these physical and active barriers will simply not reach into fresh water sands.

If the fracturing process is thousands of feet away from the water table, then why is methane showing up in residential water wells? Methane is a common contaminant in water wells, caused by both natural and man-made causes. Part of the reason is natural occurrence with biogenic methane forming from shallow decay of organic materials and natural seeps of thermogenic methane (gas formed deep in the earth) that have been coming to the surface for millions of years, particularly in regions with shale and coal outcrops or shallow formations that share the water table with fresh water wells.

However, part of the increasing methane content in a water well may be coming from near-by improperly constructed gas or oil wells. This is a common cause of contamination in northwestern Pennsylvania, when 100 year old oil wells at about the same depth as the water wells, have either leaked from the old well or been naturally connected by faults. Although not in the risk matrix, this paper looks at both natural and man-made possibilities and suggests methods to identify the culprit and how to control those sources that do come from wells. The reader must remember that these older wells predate the invention of hydraulic fracturing and most predate any significant well construction regulations.



Testing of water wells in West Virginia showed 11% contained measurable methane content before gas drilling started (1312 well study – Daily Journal, 2011) and a small well population gas presence study in Pennsylvania/New York study showed up to 85% of water wells contained methane in a limited geographical area (no pre-drill trend line), whether or not gas drilling exists in the area (60 well study - Howarth, 2011). From the variance in these two studies, clearly the local geology makes a large difference in presence and migration of shallow methane. Since methane is odorless and nontoxic, it often escapes detection until it reaches a concentration in air where it can burn. This happens in undrilled areas as well as drilled areas, and is very common in areas of natural gas seeps such as shallow shale and coal containing areas of Pennsylvania, New York, Colorado and California. Methane concentration can increase in water wells that penetrate shallow coal seams in search of the fresh water in some coals. Coals may have as much as 90+ Percent organic content and gas that is naturally adsorbed on the organic materials in the coal desorbs as fresh water is removed, even where water drawdown is for home use. If a gas well drilled to the deeper shales is constructed improperly and the shallow gas zones are not isolated, the methane content in adjacent water wells may increase due to the gas pressure build-up in the annulus (open area between the outside of the casing and the drilled hole wall). The gas that may accumulate in this area comes from coals and shales that are not the target of drilling but can still produce small amounts of gas. Deeper formations are at higher pressures, and exposure of these zones without sufficient cementing isolation will allow gas seepage that will build up a higher pressure than was customary at shallower depths. This type of methane leak is usually low volume and is made possible by poor or incomplete cementing practices. The incidence may be noticed soon after drilling and can start before the well is fractured. This problem and its causes will be explained in the section on well construction.

Methane in the near-surface area is continually produced as a by-product from decay of organic materials by microorganisms) (Heintz, 2010). Methane generated from these real-time decay reactions in wet lands, sewage, landfills, agriculture, etc., is called biogenic methane. Thermogenic methane is formed deep within the earth from high temperature degradation of organic materials laid down millions of years ago with the sediments that eventually made up the rock. The common stable (non-radioactive) carbon isotopes are carbon 12 (C^{12} has 6 neutrons) and carbon 13 (C^{13} has 7 neutrons). Biogenic and thermogenic methane differ in the carbon isotopes they contain, with biogenic methane containing more C^{12} carbon while thermogenic methane contains more of the C^{13} carbon isotope. Recently generated methane is biogenic. Biogenic methane is nearly 100% methane while thermogenic methane may also contain some propane and butane from thermal decomposition.

Although some sources have tried to use the difference between biogenic and thermogenic gas to determine whether the gas in a water well is from natural shallow generation (biogenic) or a gas well leak (thermogenic), this approach is not accurate. Thermogenic methane may migrate completely to surface or to water wells through natural seeps (with no drilling in the area). Also, shale reservoirs such as the Antrim and New Albany shales produce significant amounts of water (as much as 30 bbls/day) with predominantly biogenic methane (EMD AAPG).

Absence of frac chemicals, such as a polymer (non-toxic), is usually the telling point of difference between well construction problems that fail to seal gas, and accusations of a frac treatment that somehow “communicates” with a fresh water sand.

The following are brief descriptions of well development activities that are expanded for the topics of chemicals and fracturing.

1. Exploration - Location of a potential hydrocarbon resource – geologic studies, seismic interpretation, petrophysical assessment; followed by leasing of mineral rights and negotiation of surface access. These are generally behind-the-scene activities but the laboratory methods and general products are well described in several industry and academic papers. The output from this work is the best scientific proposal on where to drill and where not to drill. Information on geological pre-drilling work ranges from wide area geological investigation to petrophysical evaluation of rocks and cores (Britt, 2009; Bustin; Jacobi, 2009; Kundert, 2009; Rickman, 2008; Wrightstone, 2009; Kubik, 1993)
2. Permitting with federal, state, provincial and/or local governments and meetings with groups from concerned citizens to wildlife experts may take a few months to several years. Every phase of oil and gas development is regulated in states with extensive hydrocarbon development infrastructure.
3. Initial or exploratory drilling activities, which take from a few weeks to a few months, drill into the reservoir and assess the composition of fluids in the rock and the productive capacity of the formation. As drilling progresses from exploratory to development, drilling time and expense usually drops sharply as drilling equipment and technology is matched to local geology. The pay zones and development areas are also remapped with information gathered in this step, causing many development areas to be shifted to the best areas to develop and away from areas with poor reserves, shallow hazards or other problems (Mroz, 1990).
4. The interlinked completions phase includes formation logging (data gathering), with intermediary and final well completion (or well construction) activities that focus on running various strings of casing in phases of the drilling operation, along with sufficient cement to effectively isolate sections of the wellbore as drilling progresses. Many exploratory wells are vertical wells, with horizontal wells drilled later during the full scale development phase. Each casing and cementing operation forms an individual but interconnected system of pressure barriers, all designed to keep hydrocarbons inside the tubulars and fresh or salt water sources outside the tubulars. Poor well construction that leads to barrier failure, as will be seen later, is a potential pathway for pollution of ground water. As a failure source, it can be eliminated by proven design and proper application. Testing of every upper cemented string is required and for the majority of upper well barriers (pipe plus cement), a cement bond log or other in-depth investigation is just good business practice, and may be required in some cases.
5. Final well completion and facilities and pipelines – When the final casing strings of the well are set and cemented, the blow out preventer (BOP) is replaced with a wellhead complete with control valves and connections to the production facilities. Facilities are specially designed surface vessels that aid in separation of gas, oil and water phases with no loss of any fluid, including gas. Methane may be vented or temporarily from the first few wells in an area to determine well production rates and the correct size needed for a connecting pipeline. If the well is in development stage, the pipeline will already have been connected and methane emissions during post-frac well preparation or flow back can be minimized with

saleable gas recovered, even as the frac water flows back and is separated in the facilities for re-processing.

6. Fracturing Design and Chemicals

- a. Fracturing design is usually by computer or local experience and specify frac volume, rate and other factors to achieve goals of frac height, frac width and frac length or frac complexity. Monitoring using fluid tracers, micro-seismic analysis or tilt meters is useful to check the first few fracs in an area and to tune the results of the frac models (Woodroof, 2003; King, 2011; Warpinski, 2007; Fix, 1991; Fischer, 2004). The goal is to design a frac that will stay in the pay zone, develop the maximum pay or producing formation contact and achieve maximum flow of hydrocarbons and minimum flow of produced water.
- b. Transport and storage of fresh or salty frac water, chemicals and equipment fall under the general heading of transport, and along with well construction, have been identified as a potential source of pollution. Chemical spill risk can be reduced by using double wall containers, collision-proof totes and/or use of dry additives. Surface storage vessel leaks and spills can range from less than a gallon during connections in frac fluid lines to the very rare leak of a truck load (130 bbls or 5460 gallons) or the highly unlikely leak of a full frac tank (500 barrels or 21,000 gallons) of water. Leak impact can be reduced by container mats underneath pipe connections, portable tank containment berms and tank monitoring to immediately spot leaks. Impact of frac base fluid leaks is usually minor if the leaking fluid is fresh water, since most frac chemicals are mixed into the fluid only as it is pumped into the well. Safe transport, storage and handling of chemical concentrates are major concerns. These risks are sharply reduced when non-toxic or even food-grade additives replace traditional chemicals.
- c. Mixing and pumping of the frac increases risk of leaks and spills as stored frac fluid is pumped, first to the chemical addition trailer and then the blender where sand is added, before going to the high pressure pumps and down the well.
- d. Chemicals, or more precisely, the lack of disclosure of chemical identities, have probably received and deserved the most vitriolic attacks in the “anti-frac” literature. There are very few chemicals used in fracturing and definitely not the “hundreds of toxic chemicals” claimed in “Gas Land”. Independent laboratory analysis of surface water sources used for fracs do show a variety of chemicals at trace concentrations below EPA limits, that are not added as part of the fracturing process, but instead come from agricultural sources (herbicides, pesticides, fungicides, etc.), that carry over into ground water runoff. These same chemicals are found in the raw water feed into drinking waters in nearly all areas of the country, whether or not oil and gas operations are present. BTEX, diesel, fluorocarbons, etc., have been removed from fracs in the past several years as a caution or by regulations based on fear of somehow contaminating fresh water supplies with frac fluids. Most of the fracture treatments used in shales are water with a friction reducer and no significant gelling agents – called a slick water frac. The shales respond very well to these inexpensive fracture treatments. The chemicals used in the slick water fracs are covered in detail later in the paper where chemical abstract society (CAS) identifying numbers are supplied. Further information on chemical usage in specific fracturing jobs in most of the US is available directly from www.fracfocus.org. Basic slick water formulation (Fontaine, 2008) for shales may include:
 - i. Water – About 98% to 99% of total volume - commonly fresh water (<500 ppm TDS), but increasingly containing treated produced water.
 - ii. Proppant – about 1% to 1.9% of total volume – usually sand or ceramic particles carried by the frac fluid into the fracture to keep the fracture open when hydraulic pressure is released.

- iii. Friction reducer – about 0.025% of total volume – the non-acid form of polyacrylamide (NOTE – this is not acrylamide) used as adsorbent in baby diapers and as a flocculent in drinking water preparation (Entry), and reduces friction pressure of water flowing through the pipe during high rate pumping, thereby reducing required pump horsepower output and air emissions from the pumps. Polyacrylamide is stable to over 390°F (200°C) and does not appear to decompose into toxic monomers at the 150°F to 250°F (conditions in a shale well (Carman, 2007)).
- iv. Disinfectant (biocide) – about 0.005% to 0.05% of total volume – common biocides of glutaraldehyde (a common antimicrobial used in hospitals and even municipal water treating systems) or quaternary amine (drinking water disinfectant and common over-the-counter skin antiseptics). Disinfectants are used to control the growth of certain kinds of microbes that would destroy gelled fracture fluids, or, in unusual cases, may create a sour gas generation (H₂S or hydrogen sulfide) problem in the reservoir. Safer and biodegradable glutaraldehyde blends are being produced (Enzien, 2011). These chemical based materials are also giving way to UV light, ozone, and low concentration chlorine dioxide. These non-bromine and even non-chemical methods of biological control are already in commercial use in shale fracs.
- v. Surfactants that modify surface or interfacial tension, break or prevent emulsions, and perform other specific actions are used at 0.5 to 2 gallons per thousand gallons in all or part of the fracture fluid volume in some cases.
- vi. Gelation chemicals (thickeners) such as guar gum and cellulose polymers are not frequent additions to slick water frac formulations, but may be used in hybrid fracs (that use a ungelled water to initiate the frac and a gelled water to carry some of the proppant or sand. These gelling materials are common food additives, do not break down into toxin and are not considered of concern (Hoeman, 2011).
- vii. Scale inhibitors – rarely to commonly used depending on the specific shale, prevent mineral scale precipitates, eliminating the potential for concentrating problem ions in scale and blockage of tubing and equipment. The common scale inhibitors are polymer, phosphate esters or phosphonates (similar compositions to detergents) and are non-toxic at the very low concentrations used in frac jobs (Houston, 2009; Blauch, 2009), however; lower toxicity anti-scalants have been advanced for the North Sea (Dickinson, 2011; Holt, 2009).
- viii. Hydrochloric acid (same material used in swimming pools and to clean brick and other masonry projects) may be used in some cases to reduce fracture initiation pressure (the downhole pressure needed to create the first small crack in the rock). When acid is used, the average volume is about 500 to 2000 gallons (1.9 to 7.6 m³). The HCl acid is spent (used up) within inches of the frac entry point and yields calcium chloride, water and a small amount of CO₂. No live acid is returned to the surface. Acid is not used in every job, is borderline beneficial in most jobs and has been eliminated in many areas for lack of benefit. The amount of spent hydrochloric acid (by products of calcium chloride, water and CO₂) in returned well flow that is re-injected is just slightly higher than that contained in swimming pool water that is drained into the public sewer system.
- ix. Corrosion inhibitor, one of several organic compounds that may be toxic, is used at 0.2% to 0.5% in only the acid (total inhibitor volume per frac is 5 to 10 gallons (29 to 38 liters) and only used if acid is used. The inhibitor is adsorbed on steel and then in the formation and only about 5 to 10% total (about a gallon in a million gallons of water) returns to surface in the backflow.

Chemicals returning from a well after a fracturing treatment are at a fraction (usually 20% or less for chemicals and about 40% for polymers) of what was pumped down the well (King, 1988; Friedman, 1987; Howard, 2009). Polymers decompose quickly at temperature, biocides are spent on organic demand and degrade, surfactants are adsorbed on rock surfaces and scale inhibitors precipitate and come back slowly at 10 to 15 ppm (parts per million) for several months. If these chemicals are selected to have minimum impact, (low/no toxicity, full biodegradation, etc.), then impact from initially added chemicals in a spill of recovered water is minor. Note: Fluids returning from the formation are best used as a resource for pressure maintenance in oilfield enhanced recovery operations. Deep well disposal of produced fluids (including frac flow back), is common, but there are other oil field uses for this resource including treatment for re-use as saline frac water. Surface release of any water that is high salinity and has chemicals above the specific safe limit is not a viable alternative to oilfield reuse or disposal.

7. Hydraulic Fracturing - Pumping of a frac stage may last from 20 minutes to about 4 hours, depending upon the design and intent of the frac. This period of high pressure operation is probably the only time most wells will experience pressures above a level that will force reverse fluid flow (into the formation). Fracture vertical growth may extend up to a few hundred feet or more above the pay zone in a few cases where there are no natural upper rock frac barriers immediately over the pay zone, but more likely, the frac will be quickly limited by one of dozens of rock barriers above and below the pay zone. The frac is also limited by increasing loss of frac fluid as it leaks into permeable formations as more rock is contacted by the frac fluid. Driving a fracture upwards through several thousands of feet of rock is simply not possible, given the limits imposed by natural frac barriers, leakoff and the natural stresses of the formation and rocks above the pay zone.

The intent of shale fracturing is to establish a higher permeability flow path from large sections of the reservoir to the wellbore. This may be accomplished by a vertical planar frac (looks like an airplane wing extending straight out from the wellbore) or opening the micro-fissures, micro-fractures and weak zones within the shale creating a high permeability pathway using the shale matrix. This type of complex frac may look something like a fractured windshield, Figure 3.



Figure 3
Network or complex fracturing in many shales are envisioned to be similar to that in shattered glass, forming a series of flow paths reaching out a few hundred feet from the wellbore as confirmed by micro-seismic monitoring of the fracture treatments.

In these cases, fractures open or reopen the natural fractures and weak zones existing within the shales.

The actual act of fracturing in a properly designed and constructed wellbore, is the lowest risk action involved in the well development process, especially in wells more than about 2000 feet deep. The minimum depth at which fracturing is practical and safe is set by state regulators with knowledge of local fracturing experience and geological hazards such as faults and karsts, and effective frac barriers (rocks that resist fracture initiation or penetration). State regulators may also set specific limits on well depth, frac volume, rate, type or fluid. If well construction is not properly done, then communication may be possible through the wellbore annulus (the area between the un-cemented casing and the wellbore rock wall): this is a pollution risk. The special case of fracturing in very shallow wells, particularly those at

depths less than about 2000 ft or with fresh water within 1000 ft of the hydrocarbon containing formation, is cause for concern and very careful evaluations are required.

8. Flowback of frac fluids during the first two to three weeks after a shale frac may experience fluid recovery rates of 3 to as much as 6 BPM (barrels per minute) or 125 to 250 gallons per minute, for a few hours, often dropping to 1000 bpd (29 gallons per minute or about 8 times what a garden hose will flow) within 24 hours and then quickly decreasing over several days to a few hundred BPD, or less, by the end of the second or third week. This is followed by a gradual decrease to a few BPD within a few weeks. Modeling the flowback behavior has benefits in optimizing well production operations (Gdanski, 20010). Methane production is generally absent as the first water is produced. Water rate usually drops quickly as gas production starts. Although methane venting during cleanup is still done in exploratory mode (to test rates in the first few wells in an area for pipeline sizing), development wells can be turned to the production system within hours of gas flow start.

Leaving unconventional wells shut-in for a time after the frac is being tested. Some early results are promising, but formation characteristics will dominate this decision. This may be a method of recovering less water and gaining higher production rates with little or no methane venting.

The amount of frac fluid recovered on flowback may range from as little as 5% in the Haynesville shale to as much as 50% in areas of the Barnett and the Marcellus shales. Most shales are “under saturated” in respect to water (like a dry sponge) and will trap and hold much of the water in the smaller pores and microfractures of the rock. This water is held in the small pores and as adsorbed fluids and does not return to surface under producing conditions. It does not move unless displaced by gas pressure. The water that remains in the rock appears to act as a propping agent in the smaller fissures where it is trapped by natural capillary forces.

The composition of produced water varies from the initial flow of fracture base-water at the start of flowback to water dominated by the salt level of the shale near the end of the clean-up. The environment in which the shale was initially deposited was usually marine (with salinities similar to modern sea water). Fresh water shale deposition was possible but rarer than the marine environment. As with any sedimentary deposition, the materials that were swept into the deposition area were a function of the land environment and the amount of energy in the deposition system (currents, floods, river flow, wind, wave, etc.). Volcanic eruptions, the type of organic materials, the depth of the water and the oxygen content impact what ions, compounds and contaminants are present in the shales. Materials that come to the surface from the shales are carried by water flow and both the total flow and the amount of chemicals decrease rapidly as water flow from the well decreases.

In some shales the water in the shale may contain natural occurring ions such as barium, strontium, bromine. In a few cases, the returning water may have low concentrations of heavy metals and radioactive isotopes (naturally occurring radioactive materials or NORM). The term NORM is frequently used when human activities concentrate radioactive isotopes such as uranium, thorium or potassium or their decay such as radium and radon. In the natural state, these materials are usually well below safe limits of exposure; it is only when they are concentrated that a problem may be created. Activities that can at least temporarily concentrate these low-level radioactive materials include: coal mining and combustion, some gas production, metal mining, fertilizer manufacture, building material manufacture and some material recycling (World Nuclear Association, 2011). Materials and areas with NORM and other radioactive potential within modern homes include granite counter tops, radon gas accumulation in basements, smoke alarms, televisions, low sodium salt substitutes and some glass and ceramics (EPA Radiation Protection website). Examples of radioactivity limits and sources of natural radioactivity sources are in Table 2 (modified from Texas Railroad Commission website).

Table 2: NORM and Exposure (From Railroad Commission of Texas)	
<p>NORM, or Naturally Occurring Radioactive Material, is found almost everywhere. It is found in the air and soil, and even radioactive potassium in our own bodies. It is found in public water supplies and foods such as brazil nuts, cereal and peanut butter.</p> <p>The average person in the United States is exposed to about 360 millirems of radiation from natural sources each year. A millirem, or one one-thousandth of a rem is a measure of radiation exposure. More than 80% of this exposure level comes from background radiation sources.</p> <p>Consumer products contribute 10 millirem/yr, while living or working in a brick structure can add another 70 millirems/yr. A person who smokes one and a half packs of cigarettes per day increases his or her exposure by 8000 millirems/year, while porcelain front teeth can add another 1600 millirems/year to a person's exposure level.</p> <p>Units of Measurement for Radioactivity</p>	
Microroentgens per hour ($\mu\text{R/hr}$)	A measure of exposure from X-ray and gamma ray mR/hr radiation in air. Measurement of intensity of radiation in air. A microrentgen = one millionth of a roentgen.
Picocuries per gram – pCi/g	A measure of the radioactivity of one grams or radionuclide that decays at a rate of $3.7\text{E-}2$ disintegration per second.
MilliREM – mREM/yr	An acronym for roentgens equivalent man. Relates to the adsorption of radiation on parts of the body over time. One Rem ~ One Roentgen.
Radiation Limits and Comparisons	
Limits from Texas Regulations for Control of Radiation (above background):	
For protection of general public:	100 mRem/yr
For radium in water:	30 pCi/liter
For radium in drinking water:	5 pCi/liter
EPA suggested action level for radon in residences:	4 pCi/liter
Examples of radiation exposure levels	
Terrestrial background Texas Gulf Coast:	60 mRem/yr
Terrestrial background Texas Panhandle:	120 mRem/yr
Medical X-Ray:	40 mRem
Cosmic (sea level):	35 mRem/yr
Cosmic (10,000 ft)	85 mRem/yr

NORM materials above the natural background radioactivity levels require special handling or removal and disposal (Resnikoff, 2010; NY DEC Publication, 1999). The occurrence of these problem ions in shale backflow, particularly barium ions and radioactive isotopes, are generally limited to a few areas and often are present only for a short time as natural water flow from the shales decreases in the first few days after fracturing. Disposal sites and wells that are licensed for oilfield disposal are monitored for radioactivity, although the alarms on these devices are rarely tripped by the liquids and solids brought in for disposal.

Some of the radioactive issue is centered on the Devonian shales of parts of New York, where natural radioactivity is high in soils, drinking water and specific rocks. Radioactivity levels of ions in well fluids are usually low, at or about natural background levels, and do not usually encroach on the EPA threshold unless they are concentrated by formation of mineral scale (substitution into the lattices of barium or strontium sulfate scales) or intentional trapping mechanisms. The flowback constituents will dictate the level of care required and what treatments are required for fluid disposal or reuse.

9. Production operations encompass actions taken to gain the maximum recovery of hydrocarbons from the well and reduction of water flow to the lowest level that will not economically interfere with hydrocarbon production. This often includes production of three phases of fluids; gas, oil and water, and may contain trace solids content such as rust, flakes of drilling mud, formation fragments and some solid organic materials. Production operations are usually automated with pressure and temperature sensors on the wellhead or downhole and may include other equipment to optimize or monitor production. Centralized gas compressors are probably the largest production equipment remaining after the well development process is completed. Complaints about compressor stations have centered on noise, which operators have addressed with remote siting, noise cancelling barriers, new equipment designs and low-form equipment. Pipelines are built to state and federal standards, and maintenance is required and monitored.

Frequency of Pollution Incidents in Well Operations

The frequency of ground water pollution incidents are where oil and gas activities are low in comparison to other pollution factors including natural seeps. Investigations carried out over several years are illustrated in Table 3. Investigations are carried at a state level with investigators knowledgeable about local geology and operations.

State	Study Period	# wells producing	Num. Cases Inv.	Site Related	D&C Related	Frac Related	Prod. Related	Orphan Well Related	Waste Disposal Related	P&A Related	Unk
Ohio	26 yrs	65,000	185	0	74	0	39	41	26	5	0
Texas	16 yrs	250,000	211	0	10	0	56	30	75	1	39

Many of the Drilling and Completion (D&C) incidents were cement isolation problems. Fifty seven of the 75 waste related incidents in Texas during the study period were legacy issues with disposal pits that were outlawed in 1969. Texas has a industry tax funded program that has reduced the number of orphaned wells from 18,000 in 2002 to less than 8000 in 2009, and currently is plugging and abandoning (P&A) 1400 wells per year of the remaining total of orphaned wells (Kell, 2011).

The incident rate of problems from exploration to plug and abandonment, if based on the number of producing wells would be 1 in nearly 1200, while the rate of incidents on total wells drilled in Texas (over 1 million), would be about 1 in 5,000. Note that there were no incidents that directly involved fracturing.

A second part of the Texas study included an investigation of the 16,000 multi-fractured horizontal wells that were drilled during the study period. No ground water contamination was found in any stage of drilling, well construction, hydraulic fracturing or production operations (Kell, 2011).

University “Shale Studies”

The non-technical articles on shale gas and fracturing have taken many forms, many times at extremes of the fracturing discussion. Only the ones that sought to deal with technology are considered here.

University studies on shale gas have focused on several topics, varying widely in accuracy and objectivity of their content. Five studies are worth highlighting in understanding the perceived risk and benefit: fugitive methane emissions (Cornell), gas incidence in water wells attributed to shale gas production (Duke), greenhouse gas

emissions of Marcellus gas (Carnegie Mellon), safety of the hydraulic fracturing process (MIT) and impact of shale gas on national security (Rice).

Cornell – The Cornell study (Howarth, 2011) suggested natural gas produced more harmful emissions than coal. The study used a higher GHG global warming number than the EPA standard and shortened the study time to a 20 year projection, which increased the impact of methane in the model (Methane is oxidized out of the atmosphere in about 7 to 10 years rather than the 100+ years required to get rid of CO₂). The most questioned assertion appears to be in the lost and unaccounted for gas (LUG) where it claims 8% of the total natural gas produced is leaked, vented or otherwise unaccounted for. This claim appears to be made from a mass balance of produced and sold gas from producers' PowerPoint public presentations. However; the study apparently lumps the gas used in processing into the LUG volumes, including the natural gas used as fuel for compressors, pumps, heaters and other equipment. Early work (2003 to 2006) on completions in the Piceance Basin did show 91% to 97% recovery of gas flowed during the clean-up phase (one to three days), but the average of 2 million cubic feet vented per well is 0.05% to 0.2% of the expected gas recovery of these wells, not the 8% claimed by the Cornell paper (Williams, 2007). The EPA LUG estimate of about 1% of production appears much more accurate, perhaps even excessive. A life cycle study of coal and gas reported a month later by the DOE NETL (National Energy Technology Laboratory) came to a different conclusion than the Cornell study: "Average natural gas baseload power generation has a life cycle GWP (Global Warming Potential) 55% lower than average coal baseload power generation on a 100-year time horizon and 50% lower than coal on a 20-year time horizon" (p 34 & 35, Skone, 2011).

The conclusions of the Cornell study have been refuted by four recent studies (Skone, 2011; Fulton, 2011; Jiang, 2011; and Barcella, 2011), all of which reached the conclusion that gas had a much lower GHG footprint than coal. These four studies refuting the Cornell findings have received almost no media attention.

What many industry may see as a take-away from the Cornell paper is that the topic of methane emission control in natural gas operations should be continuously examined by operators with the focus on reducing methane emission to the lowest point. The emission concerns raised by the Cornell researchers are readily solvable; low pressure methane recovery is feasible, especially on development wells and particularly where pad operations group wells into a small location.

- Duke – The Duke University study (Osborn, 2011) was of a small number of water wells (60 wells out of perhaps 20,000 unregulated water wells drilled in Pennsylvania and New York each year) and claims a link between methane in the well water and shale gas production operations. Methane is found in most water wells in this area (85% from this study), many of these wells showed methane where no drilling had occurred. The conclusions drawn by the authors of the paper and various of their media comments appear at odds with some of the actual findings within the study. Comments:
 - One problem with the study is that it does not establish base line methane content data in any area they sampled. Questions were also raised about the small sampling and some sample methods. The authors have since proposed a 100 well study in cooperation with industry (Jackson, 2011).
 - Methane was found in 51 of the 60 sampled water wells, regardless of whether gas industry operations were in the area, and the authors offer no explanation of this occurrence or why thermogenic gas (opposed to more common near-surface biogenic gas) was found in all but one of the samples. Especially curious was the occurrence of thermogenic gas in areas where no gas production operations occurred. Thermogenic gas found near or at the surface is a strong indicator of natural seeps, yet no mention was made of the documented seeps in the area.

- The sample areas also included an area near Dimock, Pennsylvania, where a set of apparently poorly constructed wells are thought by state regulators to be leaking methane, without clear identification that the area was an anomaly in well development. “I think the most likely explanation is that there are gas well casings that are leaking. I think that’s more likely than the mass movement of gas or liquids thousands of feet underground. ... Again, we did not find any evidence for contamination from [fracturing fluids].” (*Duke researcher Rob Jackson interview w/ Bloomberg, May 10, 2011.*)
 - The Duke study is a useful data point for raising awareness about gas migration and does show potential linkage with gas drilling and well construction. The study does not implicate fracturing as a chemical pollution cause.
 - Carnegie Mellon assessed life-cycle greenhouse gas (GHG) emissions from the production of Marcellus shale natural resources against the US national average natural gas emission for the year 2008 (Jiang, M., 2011). They estimate an 11% increase in GHG emissions relative to domestic gas (excluding combustion) and a 3% increase when combustion is included. The scientific process used in this study was solid and well documented.

“The life cycle GHG emissions of Marcellus shale gas are estimated to be 63-75 g CO₂e/MJ of gas produced with an average of 68 g CO₂e/MJ of gas produced. Marcellus shale natural gas GHG emissions are comparable to imported liquefied natural gas. Natural gas from the Marcellus has generally lower life-cycle GHG emissions than coal for production of electricity in the absence of CO₂ capture and storage processes, by 20% to 50% depending on plant efficiencies and natural gas emissions variability. There is significant uncertainty in our Marcellus shale GHG emissions estimates due to eventual production volumes and variability in flaring, construction and transportation.”
 - MIT – The MIT study (MIT, 2010) was a properly run, interdisciplinary study, with oversight and perspective from an advisory committee comprised of academia, alternate energy, environmental, energy industry, and financial. The study focused on gas supply stability, regulatory needs, energy costs, climate policy and several other impacts in a balanced and fair manner. This was the third energy study by MIT with coal (2007) and nuclear (2003) featured earlier. The MIT findings included several points, two of which are:
 - In a carbon-constrained world, a level playing field — a CO₂ emissions price for all fuels without subsidies or other preferential policy treatment — maximizes the value to society of the large U.S. natural gas resource.
 - With over 20,000 shale wells drilled in the last 10 years, the environmental record of shale gas development is for the most part a good one — one must recognize the inherent risks and the damage that can be caused by just one poor operation.

The MIT findings were positive for the most part and pointed out a need to make sure environmental actions kept pace with shale developments: Industry actions that short-cut proper transport and well construction cannot be tolerated.

- Rice University: James A. Baker III Institute for Public Policy (Medlock, 2011) – The study findings point to increased national security driven by shale gas. “The past decade has yielded a dramatic change in the natural gas industry. Specifically, there has been rapid development of technology allowing the recovery of natural gas bound up in shale formations. By some estimates, there is as much as one thousand-trillion cubic feet (tcf) of technically recoverable shale gas in North America alone, which is enough to supply the nation’s natural gas needs for the next 45 years (Author’s note – very conservative number). This study assesses the impact of U.S. domestic shale gas development on energy security and U.S. national

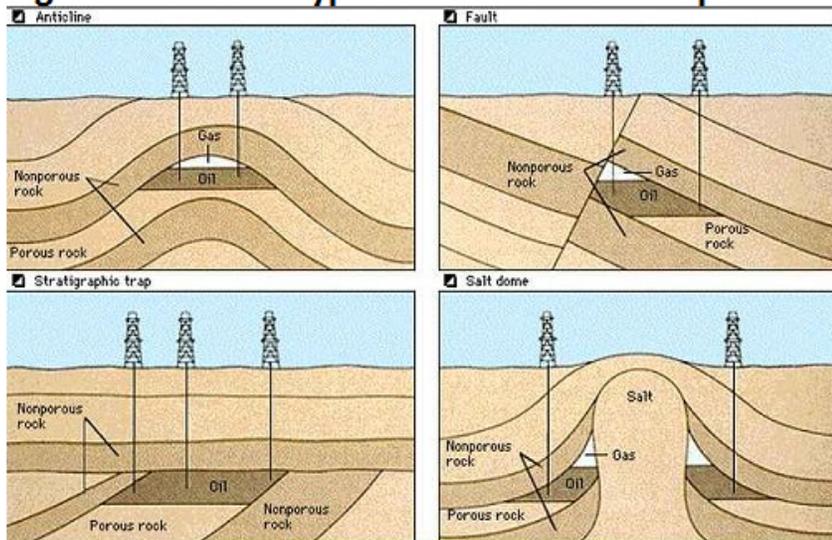
security, with emphasis on the geopolitical consequences of rising supplies of U.S. natural gas from shale and the implications for U.S. foreign policy.”

The study identifies larger natural gas and oil production as increasing US national security through potential reduced reliance on other countries for U.S. energy supplies.

Reservoirs and Seals – Why Oil and Gas is Still There and Why Frac Fluid Doesn't Migrate

If the oil and gas are still in a reservoir millions of years after being created, then the reservoir barriers will also prevent the upward migration of fracturing fluids and their additives. Conventional reservoirs, as shown in Figure 4 are formed when a rock capable of holding fluids is sealed at the top (as a minimum) by a low permeability cap or sealing rock layer. Rock-seal mechanisms forming traps that contain reservoir fluids may take one of many forms. The sealing potential of most reservoirs are stable, but very shallow reservoirs (upper right) formed along faults that penetrate to or near the surface are special cases that must be investigated and approached carefully if fracturing is to be used. Local knowledge is critical to a decision of how, or even if, to drill and complete in these shallow rocks. These types of reservoirs are rare and the known ones are often the source of natural seeps of oil and gas. Gas wells drilled and completed into these reservoirs with suitable care can reduce natural seepage of hydrocarbons to the surface; an action proved in shallow, methane producing coal seeps in Colorado (Cippe, 2006) and Monterey formations of California.

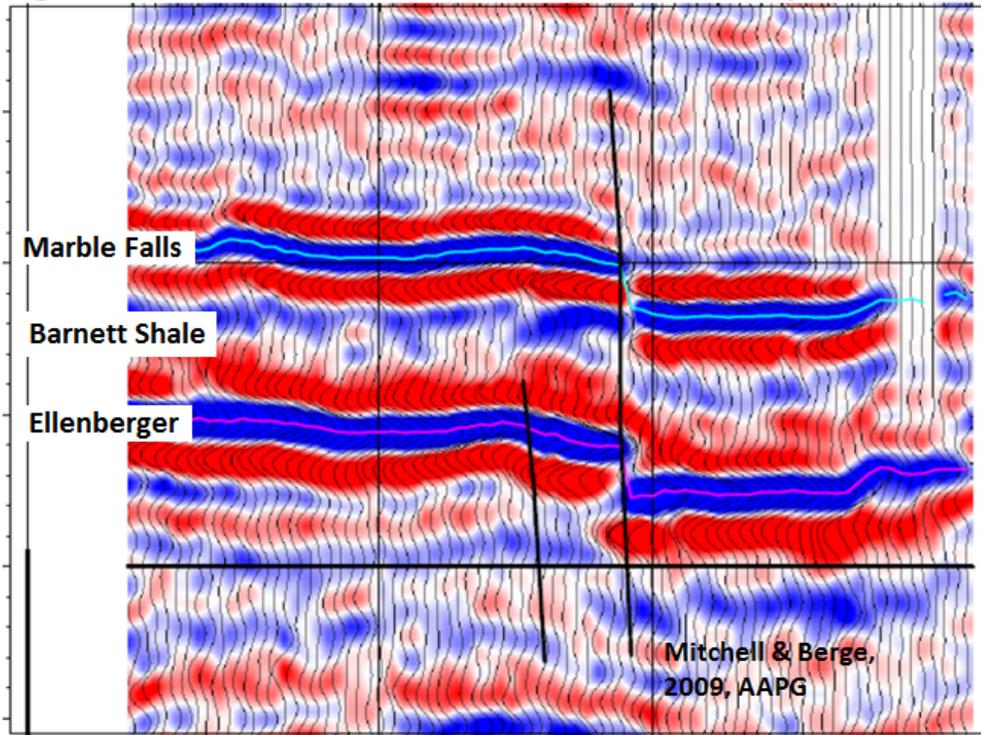
Figure 4: General types of reservoirs & traps



The fault pictured in the upper right of Figure 4 shows the fault coming completely to surface. This is extremely unusual (unknown) in a deep reservoir, but would be a concern for fracturing if it did occur. Faults that breach the surface are associated with natural seeps of hydrocarbons and brine waters.

Faults are common in the subsurface and larger faults that may cause problems are visible on seismic images, Figure 5. Seismic recordings, either 2-D (two dimensional) “lines” of seismic shown in the picture or 3-D seismic that shows a broad area of the subsurface are a fundamental tool of exploration and are highly useful for avoiding geological hazards.

Figure 5: Barnett Fault - Area avoided in well development.



Where formations “outcrop”, or come to surface, faults show the effects of tectonic stress relief along with the smooth overlay of other rock types, Figure 6.

Figure 6: Faults shown in outcrops



Historic, often deeply buried faults and folds have a vertical travel or “throw” of a few inches to a hundred feet or more, and may be a few feet to hundreds of miles long. For most gas productive shales, faults are located far enough underground to make surface communication impossible. Movement of such a deep fault in a producing field (with a fault length of a few hundred meters) may have a movement of a fraction of an inch (worst case scenario).

The mechanism that keeps gas, oil and salt water in a reservoir is commonly made up of numerous rock seals, Figure 7, and structural or rock fabric traps. These seals are very low permeability, very fine grain rocks, with permeabilities and pores far below the size than will allow gas to easily move through the rock. The proof of the containment capability of these rock seals is the fact that oil, gas, saltwater, etc., are still there: the lighter gas and oil has not migrated upward through the heavier salt water. Cap rocks or the seals above the reservoir, are very

durable, having resisted uplift, seismic activity and other stresses that formed fracture sets in more brittle rocks. This ductile characteristic is also noted to stop hydraulic fractures.

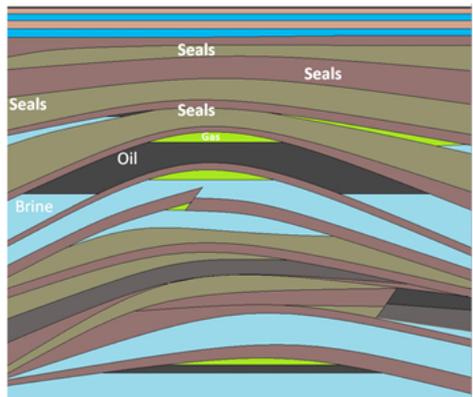


Figure 7: Seals and Structures

Gas and oil, as well as brines (salt water), have been held in place millions of years by literally hundreds of barriers and seals.

These massive seals also serve as one of the barriers that keep fractures from growing upwards towards fresh water supplies.

Most conventional rocks are filled with water when the sediment is deposited. When a source rock, such as gas or oil-productive shale, is in contact with a sandstone or limestone that is sealed at the top and sides, the oil and gas generated by decay of organic materials in the shale migrates up and is stored. When first drilled, these reservoir rocks contain varying levels of water, oil and gas in the pores of the rock – the industry calls these saturations of water, oil and gas. As fluids are produced, the pressure is decreased and flow rates drop due to limited driving pressures. Where possible, the produced water should be re-injected into the reservoir to help maintain the pressure, to push fluids toward the wellbore and to minimize subsidence. Productive shales are both source rock and reservoir rock, generating large quantities of oil and gas from organic materials laid down with the sediments, but a large part of the hydrocarbon remains trapped in the shale by the low permeability; this is where hydraulic fracturing is needed.

The level of permeability in a rock holding oil and gas dictates whether the reservoir must be hydraulically fractured. When permeability is high enough, roughly 50 md for most oil zones or about 1 to 5 md for gas zones, fracturing may not be needed to establish an economic production rate. At lower permeabilities or where oil viscosity is high or reservoir pressure is low, the flow of fluids toward the wellbore can be assisted by fracturing, which creates a flow path of much higher permeability. Stable fractures offer a flow path with average permeability of 100 to over 1000 times the permeability of the formation (Gaskari, 2006). At lower permeabilities, such as shale, most wells will not flow economic quantities of fluids without extensive hydraulic fracturing. In low permeability formations, the fracture network within the formation, Figure 8, creates contact with the micro-fractures and fissures in the formation but must be enlarged to provide a flow path to the wellbore.

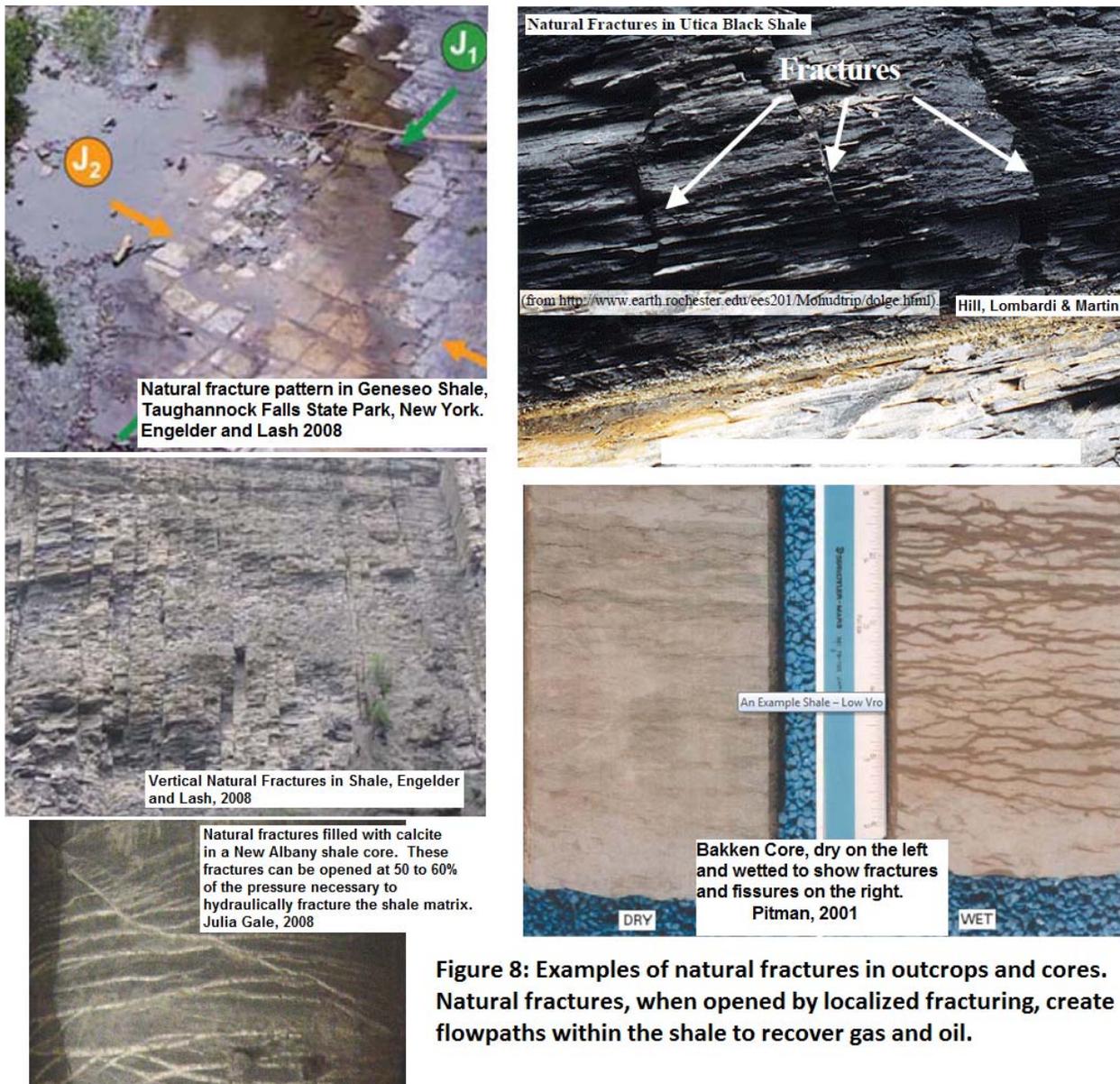


Figure 8: Examples of natural fractures in outcrops and cores. Natural fractures, when opened by localized fracturing, create flowpaths within the shale to recover gas and oil.

Hydraulic fracturing in shale opens, enlarges and stabilizes natural fractures or weak zones in the shale fabric. Natural fractures are a result of many factors from tectonic forces after deposition to the pressure created as hydrocarbons were created. Natural fractures in the shales, Figure 8, are often found in shale outcrops, but may also be seen in cored samples from shale reservoirs. The initial fracture pressure can widen and link these natural fractures to form both contact area with the formation and a more stable flow path for production of fluids within the shale.

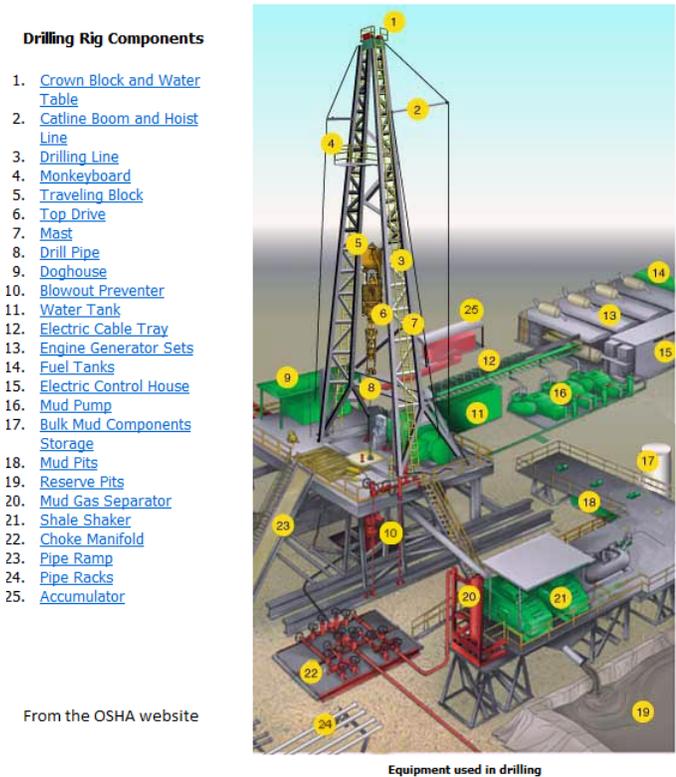
Many natural fractures in cores are closed or sealed, and some other shale cores show no presence of natural fractures. Work on opening natural fractures has been advanced with results showing that natural fractures, even when closed or sealed by calcite, could be opened by about 50 to 60% of the pressure needed to fracture the matrix of the rock (Gale, 2007 & 2008). This points to a method for developing both the extensive surface area contact required and establishing a flow path to the well.

In unconventional rocks such as shale, the formation and the seal rock may be the same rock. In cases of oil and gas productive shales, this type of reservoir, first tested in the early 1800's, were usually too low rate to be attractive to development. In the 1970's, a US Government DOE grant helped companies, coordinating through the Gas Research Institute (now the Gas Technology Institute or GTI), adapt existing technologies including slick

water fracturing, horizontal wells, stepped-rate increases and multi-stage fracturing into shale-focused technologies. The technology increases improved gas recoveries from shales from a level of 1% recovery in the early 1990's to over 40% by 2010. There are over 40 shales either under investigation or development in North America and dozens more being studied world-wide.

Drilling and Well Control

Although the focus of this paper is on fracturing, all well development issues are inherently linked, thus a short discussion on drilling and chemicals used in drilling mud is important. Drilling the well, from the surface to the end of the well in the producing zone, may take several weeks and utilizes many pieces of equipment, specialized techniques, and some chemicals. The drilling rig is the most visible part of the operation, but it is what happens underground that is the most important. A simple drill rig schematic with the supporting equipment is shown in Figure 9.



The primary objections to drill rigs appear to be noise (can be reduced by using electric rigs), visual (drill rigs involved in most unconventional well drilling are from 50 ft to over 100 ft tall), dust (if air drilling is used, special equipment is required to control air and cuttings), time on location (usually 2 to 5 weeks), water and mud storage (pits or steel tanks), chemicals in the mud (typically natural bentonite clay, barium sulfate weighting agent and water), pressure control (both surface and subsurface) and air emissions from diesel engines. Each of these objections can be addressed through the proper application of technology:

- Noise and emissions – increasing use of electric rigs, more common on condensed pad operations, are reducing noise and controlling emissions. Sound barriers are also common around compressors and other cyclic and continuously operated equipment. Apache's efforts on pads have also included powering lighting, local generators and other equipment with natural gas produced on the pad, rather than diesel fuel.
- Visual and time on location – lower profile rigs are used when possible on shallower wells, but the trade-off is that the larger rigs are usually faster.
- Dust and traffic – paving of roads, re-routing heavy or frequent loads, scheduling crew transfers at off peak times and dust mitigation on air drilling projects have been used to reduce dust and traffic. A major

reduction in traffic, dust and emissions is to use pipelines to transfer water to and from the well location, sharply reducing truck traffic.

- Liquid storage and chemicals – Areas of concern are recovery, storage and transfer of salt water used or recovered in well operations. These concerns can be address with covered storage, steel tanks or other environmentally acceptable alternatives (Patel, 2009). Most chemicals used will adsorb in the formation or be spent (degrade) on use. Minimum chemicals are used in mud with the intent to establish a closed loop system (total reuse).
- Pressure control equipment - This equipment, particularly in light of the Gulf of Mexico Macondo oil spill and some incidents in Marcellus, has received a fair bit of scrutiny. Pressure control equipment is reliable if it is serviced and inspected regularly. There are regulations on equipment required and testing regimens that must be recorded.

Types of Mud

Water-based mud (WBM) may be any formulation from fresh water to water with viscosifiers, weighting agents and various chemicals to control formation properties such as swelling clays. Fresh water is used as a base fluid in shallower depths to minimize problems with even a small amount of expected leakoff in shallow, highly permeable formations. As the well is drilled deeper, weighting agents are added to control increasing pressures. The formulation of muds for near-surface depths includes viscosity increasing clays such as bentonite are a combination of finely ground native clays that are suspended in the fluid to generate a texture of a milkshake.

The density (weight of the fluid volume) of the mud controls the formation pressures and, along with the blowout preventer, the surface casing (the pipe set after drilling a stage of the well) and proper cementing, these elements form a multiple-barrier, pressure control system that is well proved. The well pressure is kept in check so long as the mud weight and mud tank levels are monitored and regular “flow checks” are performed to make sure the mud weight is sufficient to prevent flows from the formations being drilled. As higher pressures are encountered in deeper formations, the mud density is increased to offset the pressure and additives may be necessary to prevent clay swelling (Patel, 2009).

Only water based mud is used for near surface drilling. Oil based muds are used where water based muds cannot control formation instabilities such as swelling clays. Oil based muds are not used for near surface drilling. The oil based drilling mud options may include oil based muds (OBM) and synthetic oil based muds (SBM), which have less environmental impact potential.

On a drilling rig, mud is pumped from a mud storage tank (often called a pit, even when it is a steel tank), down the drill string to the bit where it exits through nozzles, cleaning and cooling the bit before lifting the cuttings to the surface. Lifting the cuttings up in the space between the outside of the drill string and the drilled hole requires sufficient velocity and a fluid with viscosity. The returning mud can contain natural gases liberated by the bit that separate from the mud at the gas-buster and are reclaimed, vented, or flared, depending on regulations and the equipment in place. Monitoring equipment for high gas accumulation is commonly required and must be routinely checked and maintained. Cuttings are separated or filtered out of the mud and the mud returns to the mud storage tank. Depending on the source of the cuttings, they may be disposed of in a landfill (no oil or high salt loading) or disposed of as oilfield waste in an approved facility. Cuttings radioactivity in areas with high natural radioactivity (New York), has been studied, with problems predicted mostly with cuttings that were not sufficiently dewatered before disposal (Resnikoff, 2010).

Air drilling (with air as the circulated fluid) is very common in some areas, generating very fast drilling to place the near-surface casing strings with no potential of chemical spills. However, air invasion of water sands, while not toxic, can result in taste, odor and color changes to fresh water through bacterial interaction, iron oxidation and sediment disturbance. These effects are nontoxic and temporary but should be explained to the general public and balanced with remedial action before drilling activity.

Well Construction, Well Integrity and Life-Cycle Considerations

As will be shown in data throughout this paper, well construction is the dominant source of non-transport pollution problems in well development, including most that are erroneously blamed on hydraulic fracturing.

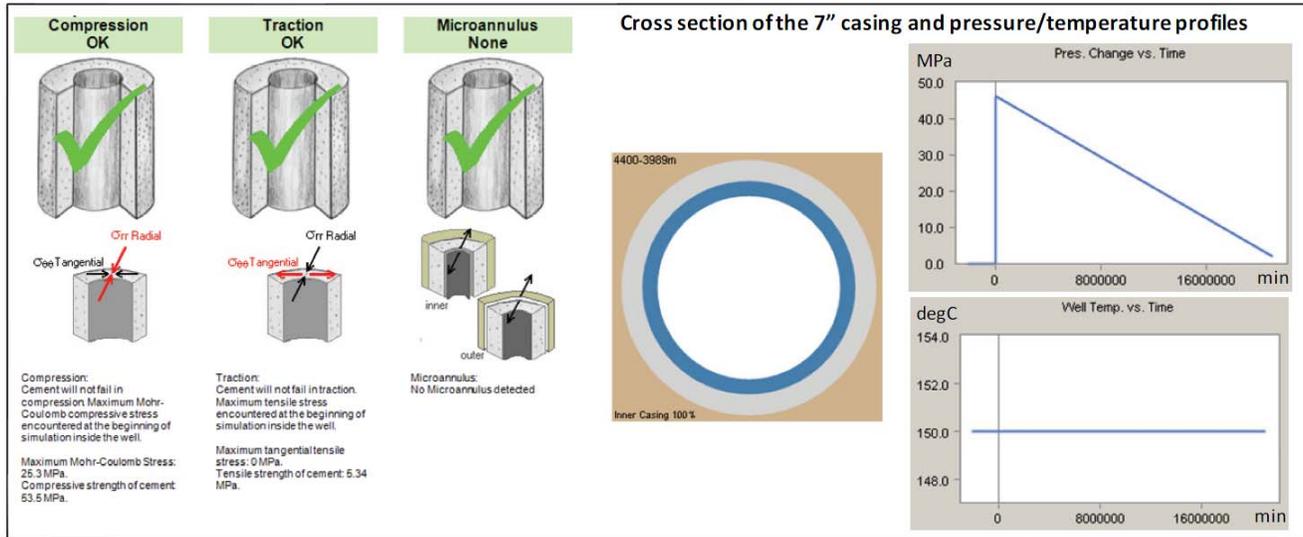
Well construction problems are reasonably rare, with about usually 1 to 5% of initial completions requiring a workover to repair before the well will pass the tests required to drill deeper. Testing of surface strings are required and typically inspected by state regulations; however, there is no “one-size-fits-all” approach. Engineering standards and approaches can create a well-specific design suitable to control any fluid, any reservoir or frac pressure and last longer than the projected life of production potential. However, the design is only as good as the application. A well is designed from the bottom to the top and from the inside to the outside, with the pipe size set to the required fracturing rate or size of the pump at the bottom of the well. It is designed to work as a unit, but built one piece at a time.

The accepted approach is to design the well to be a pressure vessel with a life span far in excess of the producing life of the well (Miskimis, 2009). A good well design should protect the non-oil or gas zones, including fresh water aquifers, from produced hydrocarbons, protect the well from formation problems external to the well such as corrosive gas or salt water, and protect against earth forces ranging from earthquakes to subsidence forces created by fluid removal in unsupported formations. The basics of this type of design must take into account tensile, shear, rotational, collapse and burst forces and the desire is to achieve a design where, when a failure does occur, that the inner pipe of a multiple barrier well will collapse before the outer strings burst. This approach may create a need for a workover to repair the flow path of hydrocarbons, but it leaves the outer protective barriers intact, preventing pollution.

Well construction begins by running jointed casing, coupled together as it is run into the hole, to create a long “casing string”. Cement is then pumped down the pipe and up the annulus (the space between the outer pipe and the drilled hole). The combination of the casing and cement form the barriers to leaks or flow during drilling, fracturing or production. The near surface casing strings are set at specific depths to protect the surface and the near surface fresh water aquifers that may extend to 1000 ft. (305 m) below the surface (typical depth is about 300 ft. or 91 m). The surface strings must be set several hundred feet below the deepest fresh water sands, preferably into a sealing rock strata and the cement must be placed from bottom to top. Actual depths are set by state regulations. Achieving a high quality cement seal is a critical step – it cannot be treated as an afterthought. Pressure testing of this surface string is mandatory. A secondary confirmation step may involve a cement bond log (CBL) or other tool to test the bond strength of the cement to the pipe and to the formation wall. Cement evaluation tools also help find mud channels in the cement which, if extensive or continuous, could be a pathway for unintended gas or liquid flows along the annulus. A single cement inspection tool is not appropriate for every cemented string, but the tools are a broadly applied technique for assessing cement seal in a manner beyond that of a pressure test after cementing (Talabani, 2004; Postler, 1997).

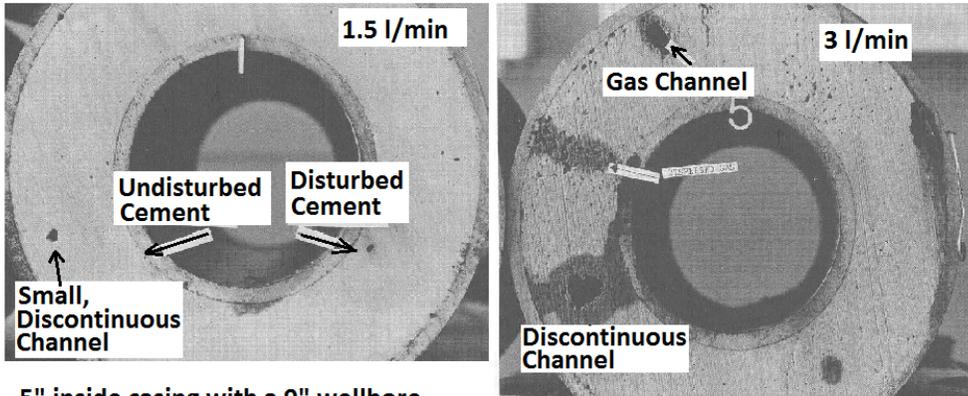
Cement, if properly formulated and placed in a well with correctly positioned centralizers, is an extraordinarily long-lived seal. A 40 year old cemented well example from a proposed CO₂ sequestration field that was tested with a battery of tests and devices shows the durability of cement isolation, even after a 6500 psi (435 bar) reservoir pressure drop, Figure 10 (Miersmann, 2010).

Figure 10: Impact of 40 year long production history with 6500 psi (435 bar) pressure drop. Cement still passes all tests to qualify for CO2 containment well. (Miersemann, 2010, SPE 139506)



Problems in cementing are mostly from poor placement steps, lack of centralization in the casing string and from gas migration through the cement as it sets (Al-Yami, 2009; Carter, 1973; Dean, 1992; Garcia, 1976; Gottschling, 2009; Haijin, 2010; Lewis, 1987; Loizzo, 2008; Sabins, 1997). These problems lead to mud channels and voids in the cement through which gas and other contaminants may flow if the voids are continuous. Surface test results on causes of channels and methods of prevention help illustrate the problems (Griffith, 1992). Figure 10 shows the variety of forced gas channels (worst case scenario) in cement, from the small, 1/8" to 1/4" (3 to 6 mm) channels that are believed to be typical, to the very uncommon large channels of about 1" (25 cm). These photos are of intentionally channeled cement from a laboratory study.

Figure 11: Forced gas channel creation in a laboratory using deviated pipe (worst case scenario) (Griffith, 1992, SPE 24573)



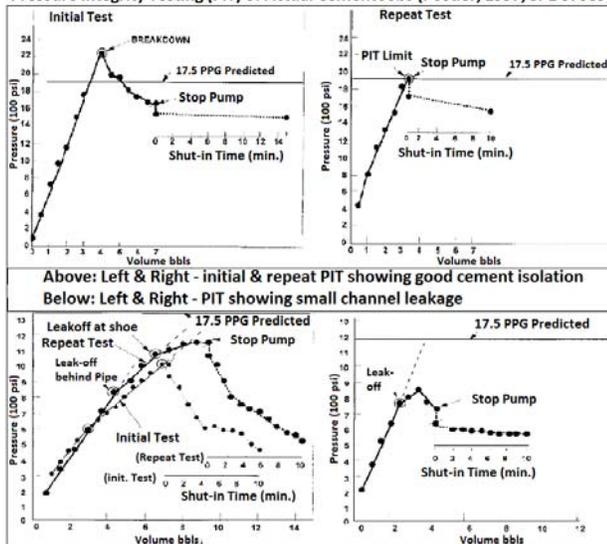
**5" inside casing with a 9" wellbore
 500 psi pressure differential and channels less than 5 feet long.**

If the channels in Figure 11 were continuous and communicated with the cement at the end of casing, they could easily be spotted by the pressure integrity test, Figure 12. Note that the shape of the curve is very different for the upper example where no leaks were found and the bottom tests which all showed leaks.

If the channels behind pipe communicate with the zone to be fractured, a cement bond log, sonic tool or other channel determining method is warranted (Griffith, 1992; Blount, 1991; Hayman, 1991; Pennebaker, 1972; Talabani, 1993). Cement channels are usually not continuous over long distances, but micro-annulus (hairline cracks between the cement and the pipe and gas migration communication is a problem that must be addressed. The potential for chemical or frac fluid communication through these ultra-small pathways is near zero, considering the short duration of a frac and especially for longer cemented intervals, but small volume gas

migration (random bubbles) has been reported in conversations. Whether this gas is from near surface or deeper has not been determined due to difficulties in catching a testable sample from the sparse bubble emissions.

Figure 12:
Pressure Integrity Testing (PIT) of Actual Cement Jobs (Postler, 1997, SPE 37589)



The casing strings for surface or fresh water protection are the largest diameter pipes and all other drilling and pipe strings must be nested or telescoped through the upper string. When a seal is not achieved or fails, the problem usually lies in failure to centralize the pipe, to displace the mud prior to cementing, or to generate a sufficient height of cement. Each of these factors is necessary to effectively seal the annulus and control gas migration along the wellbore. Attention to chemical additive toxicity has driven development of environmentally acceptable cementing additives based on cellulose and classed as PLONOR (pose little or no risk) by OSPARCOM (Oslo-Paris Commission) countries (Dao, 2002).

After the surface string has been set, cemented and tested, the next drilling operation is to drill to a deeper formation, either the gas or oil productive zone or a deeper zone that, when cased and cemented properly, helps form a second barrier. The length of this second casing string is an area of concern and the sequence of formations and the fluids the casing and cement isolate must be considered in deciding how long this upper or outer production string can be. Local geologic and well knowledge is the best source of information. There is no single "best" approach.

Although drilling pressure control can often justify a long casing string, the practice is only sound if a cement column that is placed will control the salt water and gas inputs during production (assumes full isolation of gas and salt water bearing zones). If an insufficient amount of cement is used, thin layers of exposed (uncemented) rock, including shales and coals that contain gas will result in gas seepage along the annulus and can allow high pressure charging of shallow formations by deeper formations, Figure 13. In some cases, a poor design may lead to increased methane presence in shallow zones that ultimately might break through to fresh water sands. Note that a fresh water well, also illustrated in Figure 13, would likely produce some methane regardless of oil and gas drilling, because of the shallow coal seams penetrated by the fresh water well. Coal that contains adsorbed methane will start to produce the gas as fresh water is produced.

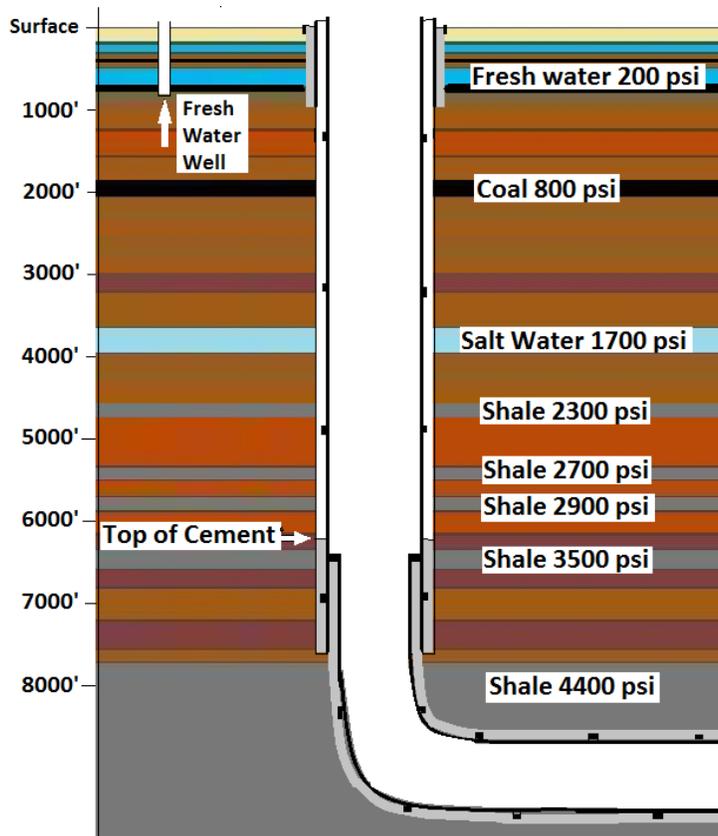


Figure 13:

Example of a well design that isolates the fresh water, but does not isolate several shale, salt water and coal zones - this design may cause problems regardless of whether the well is fracture stimulated or not.

Since the pressure in the zone usually increases with depth, the deeper, non-isolated shales and coals that contain gas will expose the annulus to higher pressures. This will slowly create higher gas pressure at shallow depths and may lead to migration of methane into fresh water zones.

An effective cement job will prevent migration of gas and pressure along the wellbore.

NOTE: The fresh water well pictured in the upper left corner would very likely experience methane gas as is produced whether a gas well was drilled or not because it penetrates two coal seams that may contain and produce methane gas as the water is removed.

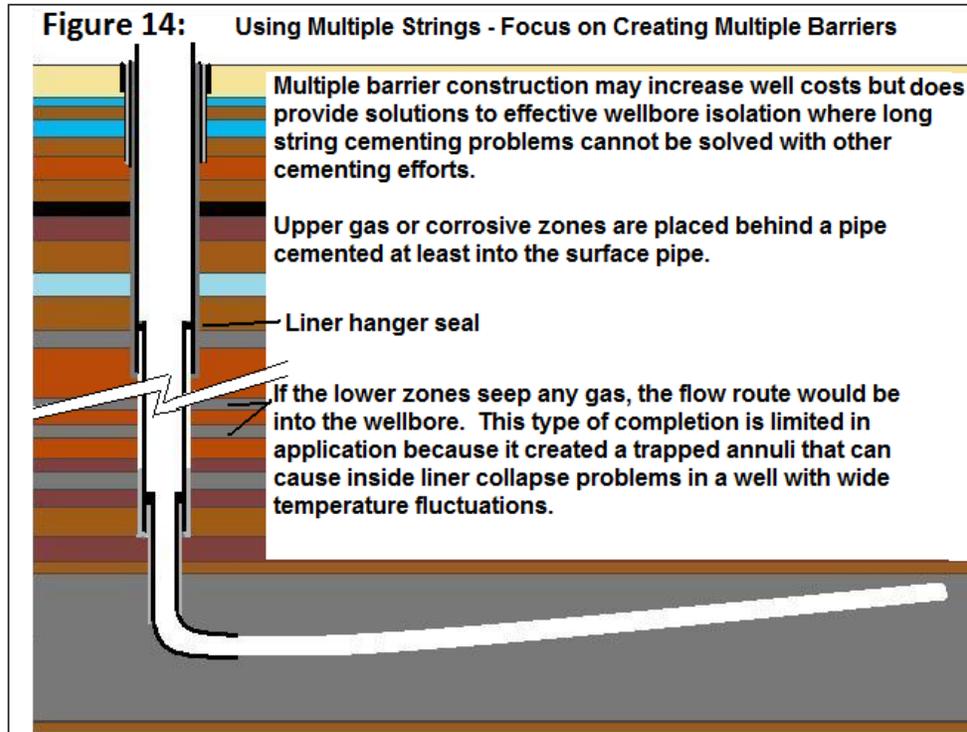
Proper casing and cement barrier design must consider the potential for behind-the-pipe flow (flow in the annulus). Gas seepage of this manner is a well construction problem and can occur with or without fracturing of the pay zone.

The importance of effective cement seals cannot be over-estimated. Cement is a strong, durable, very long-lasting barrier as long as it is mixed and placed properly. Special formulations and additives are available for increased resistance to gas migration, naturally occurring chemical ions, low pH environments, CO₂, high temperatures, sulfate, mineral acids and other factors. The design, application and monitoring of oil field cementing practices is a technology in itself, spanning over 100 years and researched in detail by technical papers, beginning in the 1930's (reference OnePetro database at www.spe.org).

Poor cement jobs are influenced by three main problems:

1. Failure to bring the cement top high enough in the annulus. Bringing the cement top higher in the wellbore will solve many issues, but cementing the full casing length from bottom to top is not always needed and cannot always be accomplished in a single application due to risk of fracturing formations with the pressure of a full column of cement that is nearly twice the weight of water. A full column of cement would exert pressures on the rock that are high enough to fracture the rock, which would lower the final top of cement in the annulus and damage formations. Lighter weight cement and/or more expensive two stage cement job are options, but the key is covering all producing zones with cement that effectively seals the intervals. The amount of cement required is set by local conditions of gas changed formation exposure and formation pressures.

Running two strings of pipe instead of a single long string, Figure 14, is another method for applying a step-wise barrier, although the cost of larger surface pipe, an extra steel casing string and the time required to run and set the extra string make this option expensive. The best barriers are those that can be confirmed by pressure testing and logging and can easily be rechecked as needed.



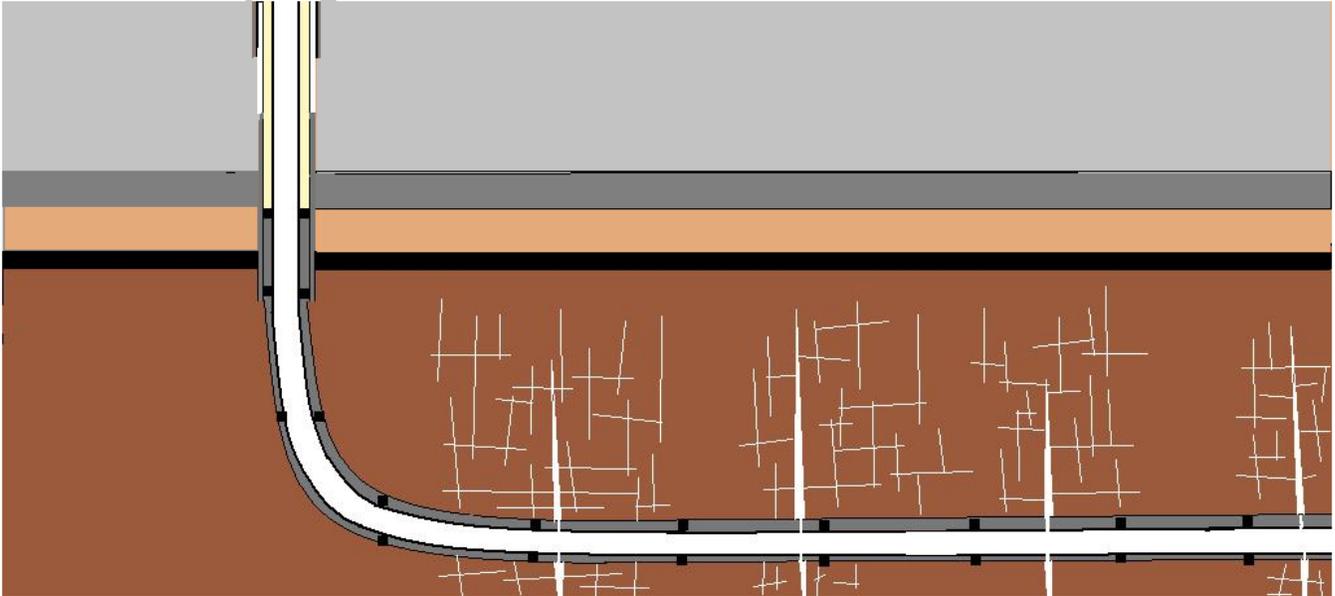
2. Failure to get cement around the casing and completely displace the mud. The cement seal depends on filling the annulus with uncontaminated cement and bonding to both the steel casing and the wall of the drilled hole. The casing must allow the cementing preflush to flow around the entire circumference of the casing, displacing the mud and cleaning the mud film off the pipe and the formation. Reasons for failures include lack of centralizers in the cemented section, poorly designed preflush (the main cleaning step), and use of insufficient cement.
3. Gas migration in the cement. During drilling and completion and before the final well completion steps, the mud or other fluids in the hole must offset the reservoir fluid pressures with hydrostatic pressure to keep the reservoir fluid from flowing. When cement displaces the mud from the annulus, the liquid cement easily keeps the gas contained in the formation, but, as the cement begins to gel and progresses towards a hard solid barrier, the action of bonding to the formation and pipe wall reduces the hydrostatic pressure that the cement can exert. During this time, small amounts of gas have been shown to enter the wellbore and create small, sometimes linked channels through the setting cement. This problem has been described for over 20 years but some operators do not realize the hazard that the gas produces if it migrates sufficiently up the cement column and establishes linked channels through the cement. The volume of gas moving through these leak paths are small, but the leakage is a problem that must be avoided or annular pressures can result (Kinik, 2011; Huerta, 2009).

Risk Reduction - Effective techniques are available to control gas migration. These techniques must be applied in any cementing application in critical jobs (surface pipe, high pressure control, etc.). Additives or techniques that minimized gas movement, barriers such as swelling packers and cement accelerators applied at positions near the cement top are workable solutions to the problem.

Mitigation – if chemicals are lost from a wellbore failure into a formation, the outward penetration of the chemicals or salt fluids into a reservoir is related to the fluid characteristics, volume, pressure and amount and type of formations contacted. If the section of the well that has leaked can be isolated, a pump can be used to produce the contaminated fresh water back towards the well for recovery.

After pipe and cement isolation of the fresh water zones, the salt water zones and any stray gas intervals, the well is ready to be drilled into the producing or pay zone. There can be one to three upper strings of pipe required to completely isolate the upper formations; the required number of strings depends on local geology. The production string may extend just into the producing zone or may extend to the end of the horizontal wellbore or "lateral", Figure 15. When well completion construction operations are completed and then fractured multiple times with targeted small fracs that focus on developing fractures within the shale. Alternate completions in the lateral sections of the open hole may feature packers and sleeves to isolate fracture stages.

Figure 15: Multi-stage fractures in a pay zone. Network fracturing establishes very large contact area



The position of the lateral in the pay zone is based upon the character and reservoir quality of the rock. Important considerations include: organic richness; porosity (the void or storage spaces in the rock); permeability (the ability to flow fluids through the pores in the rock); hydrocarbon saturation (the amount of the pore space filled with hydrocarbon); rock brittleness (ease of fracturing and creating a network of fractures in the pay zone rock); and areas of higher pressure (increases storage of gas and helps move gas and oil through the rock toward the wellbore) (Britt, 2009). The compass oriented direction of the lateral may influence fracture growth and development in some pay zones depending on in-situ (internal formation) stresses caused by geologic uplift or other "tectonic" forces in the rock strata.

Risk Reduction - An accurate understanding of these rock stresses is developed with the aid of seismic before drilling and refined with logs, cores and fracture monitoring on the first few wells in a new prospective area. Stresses in the formation generally define a maximum and minimum stress direction that influences the direction a fracture will grow.

The inclination of the wellbore may be "toe-up" (the end or toe of the lateral set higher than the heel, or starting point of the lateral), flat (at 90° to vertical), or "toe-down" (the end of the lateral below the heel). Volumes of liquid produced, formation flow capacity and reservoir pressure are input variables on toe-up or toe-down design.

Some pay zone completion designs use open-hole packers and ported sleeves along the lateral that open or close, isolating or allowing access along the lateral to enable fracturing of specific intervals. Alternative designs, also very common, are completely cased and cemented completions, where a perforating gun is used to create holes that access the pay zone.

The casing must be designed to handle full producing zone pressure or full frac pressure, whichever is higher, plus safety factors set by the type of the well and the life of well requirements.

The well construction step is ended by switching out the blowout preventer (BOP) for a wellhead before the final well completions steps that include hydraulic fracturing. The multiple barriers of pipe and cement, plus the

wellhead controls and the tubing and packer that are often added to the well after the frac form the multiple barriers (usually two to five barriers) that finish out the well construction. This arrangement of pressure and fluid movement control barriers, when properly designed, applied and maintained, are the primary reasons for the near absence of incidents in producing wells.

Risk Mitigation: Local knowledge of the amount of cement required for completion takes into account upper gas or oil producing formations that may be sources of pollution behind the casing. This has virtually nothing to do with fracturing, but it can be an issue in pollution.

The length of the horizontal well is often set by lease boundaries that are reduced by the buffer areas or “offset” (non-produced area) required by states. Typical horizontal lengths may range from 2000 ft to 6000 ft with extremes of 12,000 ft or more.

Pad Operations

Pad developments in which 2 to 30+ wells are located on a single pad achieve the lowest possible environmental foot print and offer better ways of monitoring wells as well as cutting time and expense (DeMong, 2011). If fresh water aquifer contamination is a concern, shallow water monitoring wells can be drilled at the perimeters of the pads, with samples taken as needed. Monitoring fresh water wells before drilling to establish a base line and then regular monitoring after the frac can provide very early warning in case of a well construction leak and also eliminate the operation as a potential source of pollution in an area of concern. This is a primary defense in areas of gas well drilling where there are natural seeps of gas. Predrill sampling of water and other types of fresh water well monitoring is being requested by several states.

Examples of pad developments in shale gas fields are the Apache Corporation's 70K and 34L pads in the Horn River field of British Columbia, Canada (Demong, 2010). The economic drivers to pad developments include learning acceleration for drilling, reduction of roads, pipelines and less environmental foot print. Pad operations are not feasible for initial exploration of a large play, but they offer many advantages when the field moves into development drilling.

The Apache 34L pad in the Horn River Development of Northern British Columbia, Figure 16, is a total of 6.3 acres where twelve multiple-fractured horizontal wells recover gas from approximately 5000 acres. When the pad development is completed, the wells will occupy only 0.3 acres.



The 6.3 acre K pad, completed in 2010, used 16 wells with a total 274 fracs to drain about 2500 acres of reservoir. About twelve million gallons of fresh water per well was used for fracturing. Two additives, polyacrylamide friction reducer and a low concentration dispersant surfactant (later eliminated), were dispersed in the slightly heated fresh water. Time spent fracturing in this remote area was about 4 months in winter/early

spring in 2010. The 6.3 acre "34L" pad development completed in 2011, used 12 wells with a total of 154 fracs to drain about 5000 acres of reservoirs. Water from fresh water sources (local lakes) used in the 2010 fracs were replaced with brine source water from a salt water-containing formation located about 2,000ft (610m) above the Horn River shale formations (shale is at a depth of about 8,000ft or 2440m). Water and waste transport was minimized and the natural 140°F temperature of the water made heating unnecessary, reducing air emissions. The improvements were made possible by the concentrated well locations. Concentrating wells on pads also offers reductions in roads, pipelines, truck traffic, human entry and reserves migration paths for wildlife that have proven effective in minimizing impact.

Fracturing and Fracture Monitoring

Hydraulic fracturing produces a break in the rock to release the pressure applied to the rock at the wellbore. The crack that develops is narrow, usually 2 to 3 mm in width (1/10th to 1/8th inch) and grows outward, upward and outward, widening slightly until a barrier is encountered or there is sufficient leakoff into side fractures or permeable formation to stop the fracture from growing. Even at an injection rate of 100 bbls per minute (4200 gallons per minute), the secondary fractures and permeable streaks will soon absorb enough liquid from the main fracture to limit outward and upward fracture growth.

Down-hole camera pictures in a well with an open-hole completion are shown in Figure 17. The camera was built and run by Amoco Research in the late 1960's through the 1990's to study and map hydraulic fracture growth in a variety of formations and compare performance of fracture variables (Smith, 1982; Palmer, 1991). The pictures here have a total view, (width and height), of about 2"x 1.5" (5 x 2.5 cm). Depth is in feet (4500+ feet), with pressure (in 10's of psi), and time of day in 24 hour time.

Photo "A" shows narrow fractures stopping and starting again at a ¼" (6mm) thick shale break that interrupts the development of vertical fracture growth. Thicker shale layers will effectively stop the fracture growth unless pressure can reapply itself above the barrier such as happens in this open wellbore. If pressure is reduced and cannot be reapplied the fracture will stop growing.

Photo "B" is a fully developed fracture about 6 mm (1/4th inch) wide with a camera-confirmed height of approximately 20 ft. This fracture was in a limestone. The rock in the fracture is a piece of formation debris swept into the fracture after the crack was widened sufficiently to accept particles.

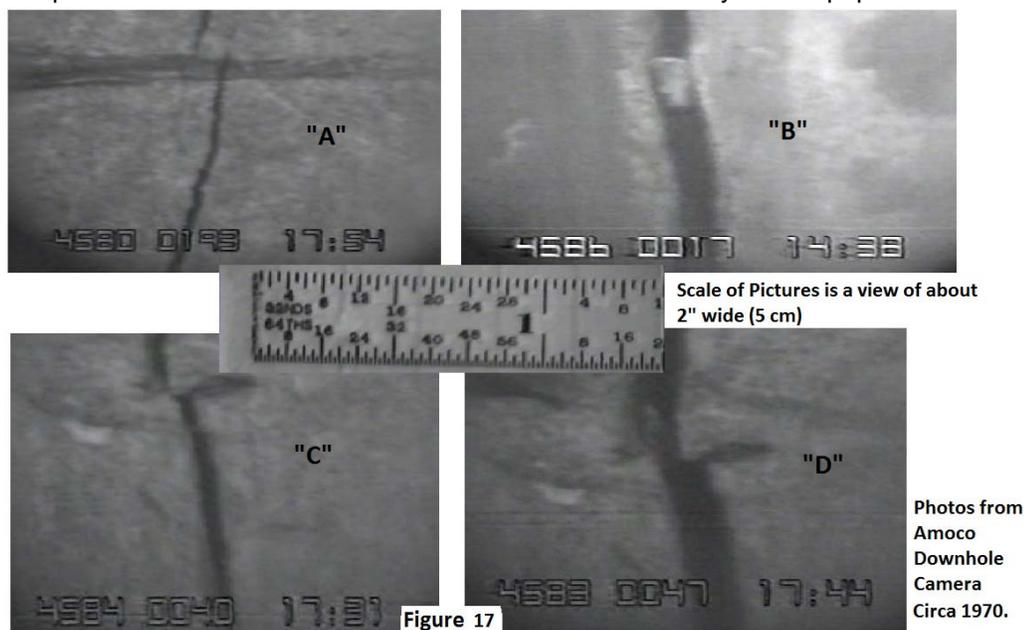


Figure 17
Downhole Camera Pictures of Hydraulic Fractures, Open Hole Completions, Vertical Wells

Figures "C" and "D" are of the same fracture. Photo "C" was after the fracture was initiated but while the wellbore was at low pressure. Photo "D" was of the same section of fracture after pressure was applied. The camera was a rare, side-looking camera that used close-ups of fractures in open hole completions to help categorize fracture

development from the wellbore. One very unusual experiment with the camera captured creation of a vertical fracture while pressuring up on a formation and pumping at about 5 bpm. The vertical fracture grew past the camera with a recorded creation rate of about 1 ft per second (30 cm per second).

Cameras are only good for viewing the surface of an exposed wellbore in clear fluid and most only work at low pressures. Only a limited amount of information on fracturing can be deduced unless the well is an open hole completion. Downhole cameras are commonly used in the industry to help diagnose well conditions. Other technologies using electrical resistance, sound, impression blocks and measurements of temperature, pressure and sound are also common diagnostic tools (Barree, 2002; Salamy, 1991; Cipolla, 2009; Kundert, 2009; Murtha, 1990; Fisher, 2004; Mulkern, 2010).

Primary monitoring methods for describing frac orientation, length, height, width and placement factors include microseismic, tilt meters, tracers, data fracs and several other technologies, Table 4.

Table 4 Frac Monitoring Technique	Frac Location in Well	Frac Direction	Frac Height	Frac Length	Investigation Timing	Specific frac flow	Comments
Surface Pressure	No	No	Indirect	No	Real Time	No	
Downhole Pressure	No	No	Indirect	No	Post Frac or Real Time	No	More accurate than surface pressure
Fiber optic, (temp, press, sound)	Yes	No	No	No	Real Time	Yes	Run on casing
Microseismic	Yes	Yes	Yes	Yes	5 min. delay	No	
Tilt Meters	Yes	Yes	Yes	Yes	5 min. delay	No	
Temperature Logging	Yes	No	Only in vertical wells	No	Post frac	Yes	Vert. Wells
Tracer Tagged Proppant	Yes	Transverse or longitudinal	Only in vertical	No	Post Frac	No	Investigation to a few inches
Chemical Tracers in frac fluid	No	No	No	No	Post Frac	Yes	Tag water or oil
Production Log	Yes	No	Only in Vertical	No	Post Frac	Yes	
Pressure Build Up, Production Tests & Interference tests	No	Indirect	Indirect	Indirect	Post Production	No	

These technologies are most actively applied during the exploratory drilling and early development, where fracturing treatments are refined and observations can be made about local geologic impacts that optimize wellbore and fracture placement.

Once the well construction, lateral placement and fracture dynamics are understood in an area, the development phase is entered and well costs can be optimized with learnings generated on the first few wells. Microseismic and tracers are rarely used in later stages of development.

Fracture modeling by computer depends on the accuracy and range of a large number of variables (Britt, 2009; Cipolla, 2009; Meyers, 2010, Smith, 1982). Formation property assumptions on permeability, porosity, in-situ stresses, mineralogy, fracture barrier locations and a dozen or more other variables with wide ranges, make the first estimates of computer modeling less than ideal. The first wells in a development are opportunities to learn. Combining known regional geology with local geology findings generated during drilling are the first solid inputs. As fracture monitoring techniques add accuracy to the assumptions, frac models will be able to improve accuracy. Most early jobs are kept small until a more optimized fracture design is constructed. Even with a more polished frac design, improvements and innovative changes will still be part of the optimization process. Local knowledge on fracturing is a very good starting point in any area.

Data gathering from hydraulic fracturing jobs can also be used to examine fracture growth and risk properties on a local or regional basis.

Hydraulic fracture height growth limits in vertical fractures from horizontal wells can be mapped with passive micro-seismic monitoring that triangulates the location of sounds made by rock breaking during shear fracturing. Micro-seismic measurements are made with a 200 to 400 ft long set of microphones in a well within a few hundred feet of the well being fractured or, in some cases with several sets of microphones at the surface. Rock breaking during fracturing will deflect slightly due to relaxation of built-up stress in the rock. In situ rock stress is the result of historical uplift, creep of salt formations and other tectonic forces. In nature these forces will build up until they reach the point of rock failure. Evidence of this rock stress relaxation reaction over geologic time is the presence of numerous small faults and a few very large faults. The energy released by rock breaking during shear fracturing has a magnitude about one hundred thousand times smaller than the magnitude of the slightest "felt" earthquake (magnitude ~3.0) (USGS calculator).

Examples of micro-seismic monitoring of upper and lower limits of fracture height growth relative to the position of fresh water as shown in Figure 18 for Barnett Shale fracs and Figure 19 for micro-seismic measurements in the recent Marcellus wells, provide the strongest evidence that the very tops of even the most unusual fractures are still thousands of feet below the depth of fresh water sources (Fisher, 2010; Fisher, 2011).

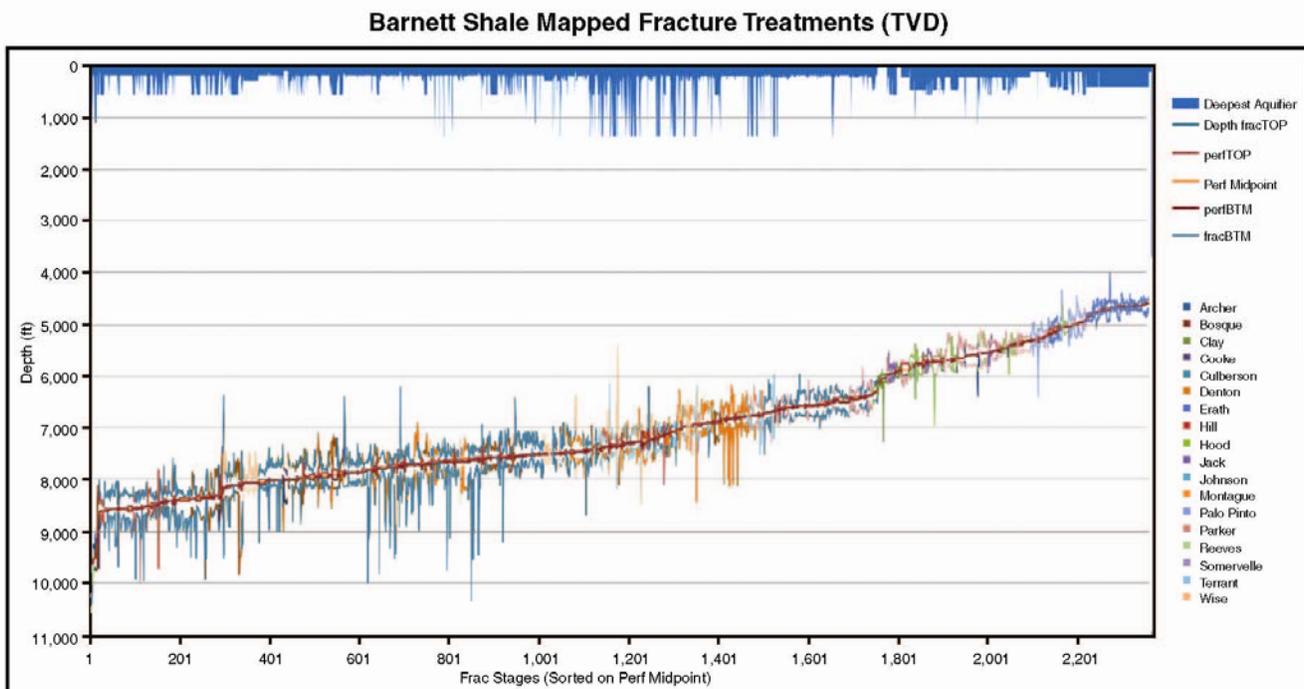


Figure 18
Halliburton Service)

(Reprinted from the July 2010 issue of The American Oil & Gas Reporter with permission from Pinnacle, A

The sounds recorded during fracturing may include sounds made by rock being stressed by the frac and some sounds that catch rock relaxing as the frac proceeds as much as several hundred feet away. In these cases, such far-field isolated sounds may not be related to the fluid movement at all.

The records of thousands of fracs were used in Figure 18 for Barnett shale micro-seismic jobs performed by Pinnacle Microseismic. Note that none of the micro-seismic records show the frac penetrating within three thousand feet of the deepest fresh water sands in the area.

Accuracy of the micro-seismic sound positioning is improved by use of the downhole listening instruments in a dedicated monitoring well and longer listening arrays with this passive monitoring technique. Experiments with one, to three listening arrays have indicated a position accuracy within about 50 feet. Tilt meters have confirmed the accuracy of fracture direction indicated by the micro-seismic units (Warpinski, 2006).

The data for the 350+ fracs monitored by Pinnacle in the Marcellus shale show an even wider margin (3500 ft) between the deepest fresh water sand and the uppermost possible penetration of a frac. These data reinforce the fracture growth limiting behavior of the natural barriers and of leakoff or loss of fracture fluid to the formations being fractured.

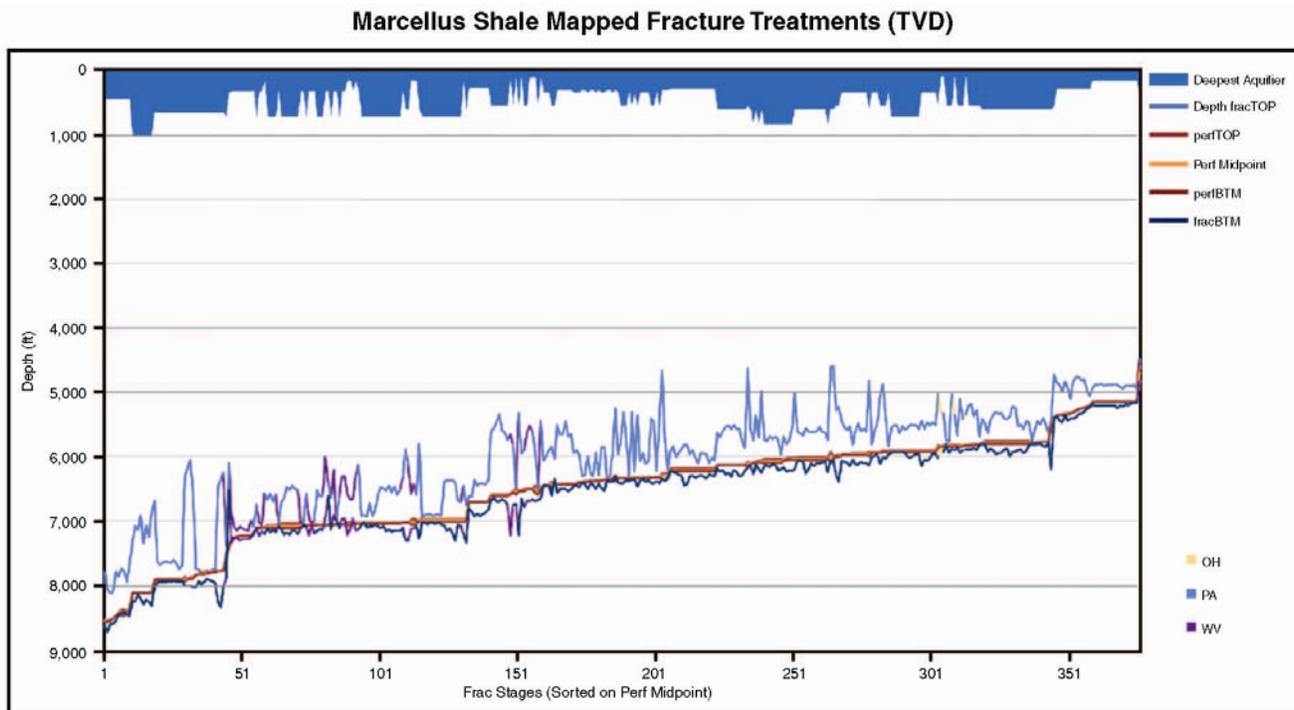


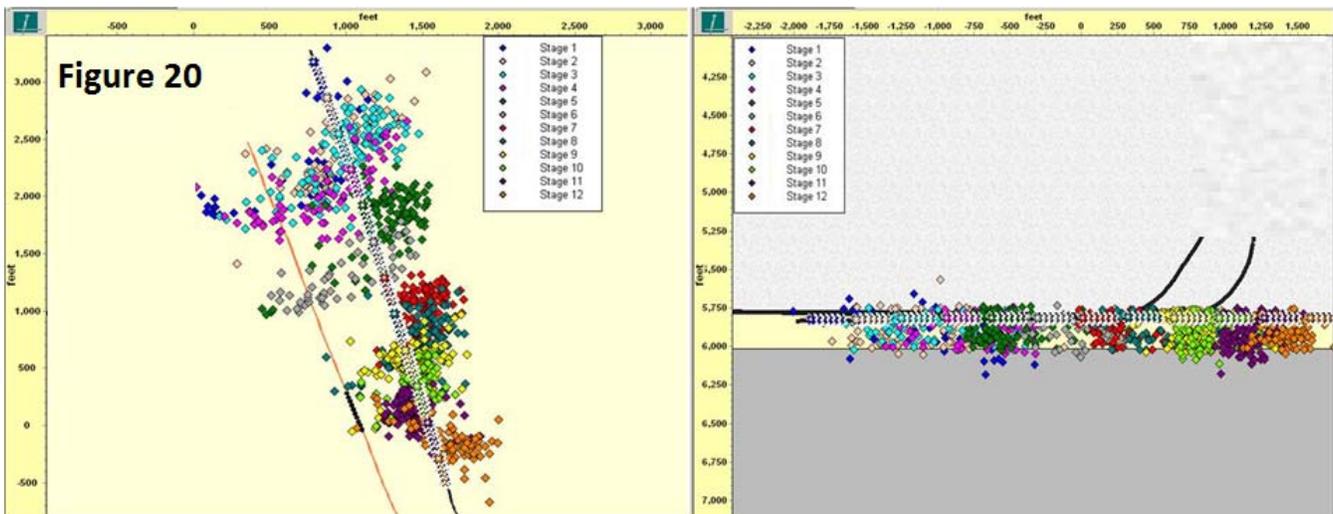
Figure 19 (Reprinted from the July 2010 issue of The American Oil & Gas Reporter with permission from Pinnacle, A Halliburton Service)

A detailed study of the limits of hydraulic fracture height growth, using micro-seismic, tilt meters, mine-back experiments and stress measurements was advanced by Fisher and Warpinski (Fisher, 2011). Data on four major U.S. shale plays (Barnett, Eagle Ford, Marcellus, Woodford) were compiled in the paper with nearly four thousand micro-seismic fracture top comparisons to maximum ground water depths across the fields. In addition, tilt meter measurements showed that the natural stresses in shallow wells (less than 2000 feet to the pay zone) were most likely to generate horizontal fractures that would not reach upward. This natural stress-induced limit on upward growth is the third control on fracture height growth (in addition to natural frac barriers and leak-off).

Table 5 is a record of the typical and closest approaches of fracture tops to the bottom of the deepest fresh water zones from the paper (Fisher, 2011). Note that not one incident of maximum fracture height growth penetrated or even closely approached a fresh water sand.

Shale	Number of fracs with micro-seismic data	Primary Pay Zone Depth Range	Typical Water Depth and (Deepest)	Typical Distance Between Top of Fracture and Deepest Water	Closest Approach of Top of Frac in Shallowest Pay to Deepest Water
Barnett (TX)	3000+	4700' to 8000'	500' (1200')	4800'	2800'
Eagle Ford (TX)	300+	8000' – 13,000'	200' (400')	7000'	6000'
Marcellus (PA)	300+	5000' to 8500'	600 (1000)	3800'	3800'
Woodford (OK)	200+	4400' – 10,000'	200 (600)	7500'	4000'

Microseismic monitoring of an individual frac job is used by some operators on the first frac in an area to help optimize the fracture design. Microseismic on a Barnett Well is shown in Figure 20. For this twelve stage frac (King, 2008), the fracture height self-limited at about 50 to 100 ft above the top of the zone, even though there were no upper or lower frac barriers in the immediate rock strata. Fresh water depth in the area was at 200 to 1000 ft, over 4000 feet shallower than the top of the frac.



The pattern of a fracture developing through a naturally fractured formation such as a shale (refer back to the natural fractures of Figure 8) was theorized in the 1980's by Yost and others (Yost, 1989) and was documented further by Warpinski when a hydraulic fracture was cored and reveled offset hydraulic fractures with polymer traces and frac sand (Warpinski, 1993).

Risk Reduction – geological analysis is usually the best risk reduction method. If risks such as major faults, karsts or other geo-hazards are noted, it may be worth further inspection with either 2D or 3D seismic as another method of investigation. Normally, the geological study for an area is reasonably complete through professional societies such as the APPG or some universities. Regardless of the level of detail available from studies, the drill bit is the best investigation tool. Careful mud logging and learnings capture is critical to success of a project. Microseismic can usually be discontinued after the first one or two wells in a given area or not used at all if fracturing operations are routinely conducted in an area without incidents. Tracers and production logging methods are often beneficial to optimize fracturing design, target better parts of the reservoir, help reduce fluid volumes and modify other parameters.

What Stops Fracture Upward Growth?

Hydraulic fracturing involves using pressure applied by a fluid (liquid, gas or foam) to create a break in the rock or enlarge the natural fractures that may be already present in the rock.

When a fracture grows in a planar style, as is common with sandstones and limestones, it conforms to a general direction set by the stresses in the rock, following what is called “fracture direction” or orientation, perpendicular to the plane of least principle stress (stresses are created by tectonic forces generated by uplift and other natural forces). The fractures are most commonly vertical and may extend laterally several hundred feet away from the wellbore and usually grow upward until it contacts a rock of different structure, texture or strength to stop the frac. These “seal” or frac barrier rocks, which stop the fracture upward or downward growth, are very common in every environment.

A second control method that stops fracture growth is the loss of fracture fluid, called leakoff, into the reservoir rock. Frac fluid under pressure is required to extend the fracture which also increases contact area with the formation. However; as the fluid increases fracture contact area with the formation or invades natural fractures, part of the frac fluid is lost to the formation, decreasing the amount of frac fluid left to drive fluid into the formation. With the large contact of thousands of natural fractures present in shales and the low viscosity of slick water fracture fluids, the rapidly increasing loss of fluids to the formation quickly matches the maximum fracturing injection rate and the fracture stops growing. This is seen repeatedly in microseismic event replays of monitored fracturing with a very rapid frac growth at the start of the frac that very often decreases to no growth during the last 10% of the job.

The formation contact area that the frac fluid creates with the pay zone in a naturally fractured formation is normally very large, often accounting for several hundred thousand to a million square feet in a densely naturally fractured shale well, all within a total extent of a few hundred feet away from the wellbore.

The technology of fracturing in unconventional formations is considerably different than the fracturing techniques used in sand control in most offshore operations or even the large planar frac developments in tight gas.

Refracturing

Many of the early shale wells in the Barnett have been refractured with very positive results; however; as fracturing processes have been optimized for shales, the positive effects of refracturing have diminished in some wells. In the case of early vertical wells fractured with gels or foams, refracturing often doubled initial production and added recoverable reserves (Dozier, 2003; Wolhart, 2002). As multi-fractured horizontal wells came into use, the effect of refracturing has diminished with improved proppant and increasing stages of smaller frac volume.

Chemicals

One of the biggest drivers of public and investor concern in the fracturing debate has been the identity and composition of chemicals used in all phases of well development (Liroff, 2011).

Although there is virtually zero chance of fracturing into a fresh water supply from a deep well, there is valid concern about even low incident potential events (in the range of 1-in-10,000 to 1-in-100,000), such as spills, leaks, cement channels and traffic accidents that could contaminate either surface or subsurface water. Although the volumes lost in these “non fracturing” events are typically very small, reducing the chemical volumes and eliminating dangerous chemicals is a responsible way forward. Green chemical development is starting in the petroleum industry and elsewhere. Given the concerns of the public, the best approach is to respond to the questions being asked and help drive the development of better chemical additive approaches and safer handling practices.

Dangerous chemicals have not always been widely recognized in any industry. Recent work in identifying carcinogens, endocrine (genetic) disruptors, toxins, by-products and bioaccumable materials is progressing. Simplifying and reducing chemical additives along with reduction to total environmental impacts are seen as a large part of the social license to operate in the world. This is a problem to be addressed and solved, not ignored (<http://www.iehn.org/overview.naturalgashydraulicfracturing.php>).

In a properly designed and executed well development plan, the toxic chemicals, principally low-dose biocides, can be replaced with materials that are effective but offer biodegradation ability and are often used in municipal drinking water preparation. The most commonly used biocides, probably Glutaraldehyde (Kari, 1993), are the same materials used in hospitals and food preparation, with relatively low concentrations but a total volume that is relatively large. One of the most pressing issues in the oil and gas industry is to examine and adopt other technologies, chemical and non-chemical, to replace as many non-green chemicals as possible (Jordan, 2010; Paktinat, 2011).

There are generally one to five purchased chemicals used in a slick water frac job, with descriptions shown in Table 6, Kaufman, 2008). However, other trace chemicals used in product preparation, as carriers and impurities, can be found in some fracturing fluids. Even the fresh water supplies used in fracturing often contain a group of common minerals and metal ions, plus several “tag-along” trace chemicals, by-products of manufacturing or trace pollutants in even drinking water, that have nothing to do with the petroleum industry (see: EPA Drinking Water Contaminants, EPA Water on Tap). These materials are usually at trace concentrations.

Detailed laboratory analysis on surface waters from ponds in agricultural areas detail a water history of traces of herbicides, fungicides and pesticides common to agriculture as well as chemicals that could only have arrived through airborne pollution from cities and industries upstream of the sample point. Nearly all of these chemicals are at the limit of analytical detection. Many of the raw, fresh-water sources for frac fluids are the same or similar to that used by municipal sources that end up as drinking water. A US city drinking water evaluation from the Environmental Working Group (decidedly anti oil and gas), lists three of their top ten rated US municipal drinking waters as being in Texas, including Ft. Worth – the middle of the Barnett Shale.

EPA lists of common sources of drinking water pollution from human activities as: “Human Activities: bacteria and nitrates (human and animal wastes—septic tanks and large farms), heavy metals (mining construction, older fruit orchards), fertilizers and pesticides (used by you and others (anywhere crops or lawns are maintained)), industrial products and wastes (local factories, industrial plants, gas stations, dry cleaners, leaking underground storage tanks, landfills, and waste dumps), household wastes (cleaning solvents, used motor oil, paint, paint thinner), lead and copper (household plumbing materials), water treatment chemicals (wastewater treatment plants) (Source: EPA Water on Tap).

Table 6: Common Additives Used in Slick Water Fracturing in Shales

Most Common Slick Water Frac Additives	Composition	CAS Number	Percentage of shale fracs that use this additive. (This in NOT concentration)	Alternate Use
Friction Reducer	Polyacrylamide	9003-05-8	Near 100% of all fracs use this additive	Adsorbent in baby diapers, flocculent in drinking water preparation
Biocide	Glutaraldehyde	111-30-8	80% (decreasing)	Medical disinfectant
Alternate Biocide	Ozone, Chlorine dioxide UV,	10028-15-6 10049-04-4	20% (increasing)	Disinfectant in municipal water supplies
Scale Inhibitor	Phosphonate & polymers	6419-19-8 and others	10 – 25% of all fracs use this additive	Detergents and medical treatment for bone problems.
Surfactant	various	various	10 to 25% of all fracs use this additive	Dish soaps, cleaners

Laws that have been enforced in western producing states for decades prevent surface discharge of most produced water and all frac returns. Some, high purity coal bed methane produced waters are allowed by exception for agriculture uses, with monitoring of minerals and chemicals.

Are Produced Water and Oil Field Wastes Exempted from Federal Hazardous Waste Regulations?

All oil field produced water (including frac flowback) and drilling waste from oil field operations are regulated by state and federal laws (EPA, 2002; Arthur, 2011). After a ten year study period (1978 to 1988), EPA exempted oil field waste from the RCRA Subtitle C regulations, stating that “oil field wastes were lower in toxicity (due to high dilution of any chemicals used) than traditional highly toxic wastes” (pickling wastes, etc.) and directed that oil field wastes be managed under RCRA Subtitle D and under other federal and/or state waste regulations. The exemption states that EPA “does not mean these wastes could not present a hazard to human health and the environment if improperly managed.” According to the legislative history, the term “other wastes” in the oilfield description, included “drilling fluids, produced water and other wastes associated with the exploration, development or production of crude oil or natural gas.” Refinery separator waste, however, is classed as a hazardous waste (since refining highly concentrates toxins) and thus, refining waste falls under the RCRA C classification: “After studying the petroleum refining industry and typical sludges from API separators, EPA decided these sludges were dangerous enough to warrant regulation as hazardous waste under all circumstances. The listing therefore designates all petroleum refinery API separator sludges as hazardous” (EPA, 2002).

Oil field produced water is regulated by several levels of Federal law and, although not considered as the high level of toxicity (as are PCP, benzene, etc.). It is still a toxic waste and must be handled under the RCRA D category. The primary disposition of produced water of any type is re-injection into oil and gas producing pay zones for pressure maintenance, water flooding and other enhanced oil and gas recovery operations. This water stream is used repeatedly in a closed-loop system. The secondary disposition of produced water is deep well disposal.

More stringently regulated oil field wastes include: unused fracturing fluids or additives (concentrates), waste solvents, vacuum truck and drum rinsates, lubricating and hydraulic oils, pigging wastes, radioactive tracer wastes, etc. (EPA, 2002).

Oil field produced waters are not drinking water sources, nor are they intended to be. Although any water, from produced water to human sewage can be processed and reclaimed as potable water, a primary objectives in the oil and gas industry is to keep produced waters away from fresh water supplies. Added to this is the need for additional water (or make-up water) to re-inject into on-going conventional oil and gas producing operations. Replacing water in the oil fields is often a key component of enhanced recovery.

Regardless of how oil field waste is regulated today, regulations in many states are expected to become stronger. The bottom line for the industry, if it wishes to avoid overly-stringent regulation that may curtail well development is “do it right”. Sufficient concerns around well development have been raised and can have serious consequences (Sakmar, 2011). Evaluating, ranking and studying environmental performance has been addressed in long term well life and several life-cycle papers (Abulimen, 2009; Miskimins, 2009, Cooper, 2011, Lundegard, 2011; Rye, 2011).

State regulations are very strong in many states and are currently being strengthened by several working groups such as STRONGER (State Review of Oil and Natural Gas Environmental Regulations - <http://www.strongerinc.org/>), Ground Water Protection Council (www.GWPC.org), Interstate Oil and Gas Compact Commission (IOGCC - <http://www.iogcc.state.ok.us/>) and chemical reporting on www.FracFocus.org, a voluntary listing of chemicals and frac information on wells in each active area. The frac reporting site is used by nearly all the major operators.

Greener Chemicals

Service vendors have been developing lower impact chemicals for several years, spurred forward by offshore regulations in the North Sea and in the Gulf of Mexico (GOM). The UK, Norwegian and Dutch sectors of the North Sea operations area has had a very positive impact on reducing toxicity of chemicals with cooperative agencies of the governments of Norway and the UK leading the way.

Lower toxicity and higher biodegradability requirements are risk-lowering actions. Chemical rating systems, which focus on biodegradation, non-bioaccumulation, low toxicity, low hazard ratings, as well as chemical reductions and replacement with mechanical actions have resulted in better acceptance of oil field operations in the sensitive North Sea areas of host countries such as Norway and the UK. Studies of offshore produced water releases and older drill cutting pile impact in Norway and UK waters have shown minimum impact on marine life or the fishing industry in those countries (OSPAR, 2007).

Chemical rating systems are not only a way for operators to find lower impact chemical alternatives; they are also a way for manufacturers to benchmark their progress in developing greener chemicals. It is worth noting that the term “green” does not have an accepted definition, so anything can advertised as “green”. The ratings systems help assign a performance level based on accepted terms.

One method, a modification of a United Nations project on chemical hazard rankings, has been put to work in assessing, ranking and selecting chemicals for fracturing operations. The illustration is from Baker’s SPE paper 135517 (Jordan, 2010). In this system, information on additives can be compared in a manner that uses environmental, toxicological and physical hazards and compares chemicals on their volume by concentration and activity %, allowing one system to be compared against another.

The first level of comparison is to appraise and score individual products, Figure 21. Maximum hazard thresholds can be set on toxicities, air and water pollutants, and bioaccumulation and minimum levels established for biodegradation. This initial screening and the optimization of chemical additive formulations can and has resulted in greener chemicals and a new market for Baker Hughes and other service vendors with similar programs (Jordan, 2010).

Figure 21
Baker Chemical Evaluation Matrix - specific chemical appraisal

Component	Methanol	Component A	Component B	Water	Total Score	Weight Score
CAS Number	67-56-1	CAS# A	CAS# B	7732-18-5		
%	x	x	x	x		
Environmental Criteria						
Acute Aquatic Toxicity	1	3	2	0		
Air Pollutants (VOCs)	3	0	0	0		
Priority Water Pollutants	0	0	0	0		
Bioaccumulation	0	0	0	0		
Biodegradation	0	1	1	0		
total score/component	x	x	x	x	176	4.4
Toxicological Criteria						
Acute Mammalian Toxicity	0	0	0	0		
Carcinogenicity	0	0	0	0		
Genetic Toxicity	1	1	0	0		
Reproductive and Developmental	3	3	3	0		
Corrosive/Irritant	1	1	1	0		
total score/component	x	x	x	x	223	5.6
Physical Hazards						
%						
Explosive					100	
Flammable					0	
Oxidizer					1	
Corrosive					0	
total score					100	2.5
Product Score (Environmental, Toxicological and Physical Hazard Criteria)					499.0	12.5
(out of 100)						

Acceptable chemicals, i.e., those with lowest rankings are then compared to achieve a product line reference, Figure 22. Although one product may be ranked lower than another on a straight material comparison, it may not be the best choice depending on the concentration of each chemical required to accomplish the chemical function. Hazards offshore may be slightly different than those in onshore operations. Areas of the country may also have different risks.

Figure 22
Baker Chemical Comparison Matrix **Modified from SPE 135517**

System A (Slick-water)	Density (gm/cm ³)	Concentration (gpt/ppt*)	Product score	Weighted system score
Friction Reducer	1.06	1	9.1	9.6
Surfactant	1.18	2	5.3	12.5
Clay Control	1.10	1	3.8	4.2
Biocide	1.36	0.05	15.0	1.0

Total System Score x 1000	27.4
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System B (Cross-linked)	Density (gm/cm ³)	Concentration (gpt/ppt*)	Product score	Weighted system score
Gellant*	n.a.	30	4	14.4
Buffer*	n.a.	5	2.5	1.5
Buffer	1.40	0.5	3.4	2.4
Cross-linker	1.13	1	1.8	2.0
Breaker*	n.a.	2	5	1.2
Surfactant	0.97	1	13.3	12.9
Clay Control	1.10	1	3.8	4.2
Biocide	1.36	0.05	15	1.0

Units for liquid and solid chemical additives
gpt = gallons chemical per thousand gallons of base frac fluid
ppt = pounds chemical per thousand gallons frac fluid

Total System Score x 1000	39.6
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Figure 22 (continued)
Comparison of Seven Surfactants Using the Chemical Ranking System

Surfactant Product	A	C	D	E	F	G	H
Environmental Criteria	4.4	4.1	2.9	4.4	3.7	3.1	1.4
Toxicological Criteria	5.6	6.6	4.1	6.8	2.2	3.7	3.9
Physical Hazards	2.5	5.0	0.0	2.5	0.0	2.5	0.0
Product Score	12.5	15.7	7.0	13.7	5.9	9.3	5.3

worst case
best case

Modified from SPE 135517

Some oil and gas operators are pushing for these products and service providers are iterating through many chemical formulations to produce products or alternate non-chemical technologies that meet requirements and regulations. Since regulations tend to be moving targets, a good record of various chemicals and mixtures of those chemicals is beneficial as more is learned about chemical effects on the environment.

Having a “greener” chemical alternative is an advantage but communicating the need to use it is often a missing element of delivering a lower environmental footprint. Apache has approached this by posting all their frac treatments on www.fracfocus.org and keeping a running summary of chemicals used in the fracs. Toxicity levels of the chemicals used are listed and a list of chemical additives to be avoided has been prepared and communicated to regions for their examination. Environmental sensitivity varies with the location, thus on-shore, marine, high scale areas, etc., must be treated differently to achieve the best results. Although initially focused on toxicity and biodegradation, the chemical watch list is being expanded to look at bioaccumulation, reaction by-products, carcinogenic materials and proven endocrine disruptors.

Risk Reduction – lowering toxicity, replacing chemicals with mechanical options or utilizing food grade chemicals are best approaches for risk reduction involving chemicals. Where disinfectants (biocides) are needed (Tischler, 2009), UV light and nano-filtration are capable of removing some levels of micro-organisms, and chlorine dioxide or ozonation (both used for disinfecting municipal drinking water) are acceptable, low impact chemicals, although a small amount of a residual chlorination may be required to insure bacteria protection (same requirement as in drinking water).

Fluid Flowback After the Frac – Is There a Danger from Fluid Left Behind?

Fluid backflow, or flowback, is the activity of cleaning up or flowing the well after fracturing to recover part of the fracturing fluid and initiate the gas production. Recovery of fluid depends on the formation and how much water that the formation adsorbs and absorbs into its structure. The amount of water in a formation, or its percent of water saturation, depends on the composition and form of the minerals such as clays at the microscopic level. If the formation minerals do not have sufficient water in their structure, they will trap and hold water from any available source until the minerals reach an irreducible water level. Water trapped in this manner may dry out again over geologic time through dry gas evaporation of the bound water, but is not likely to move during years of production. Water removed by dehydration will not transport chemicals, which will remain trapped in the rock.

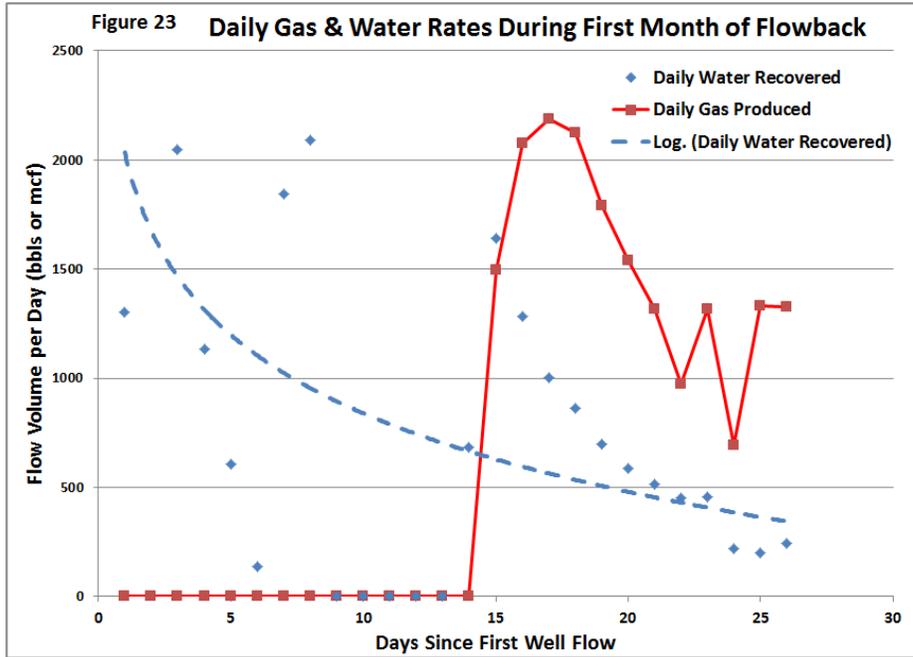
Recent work in optimizing fracturing fluid backflow has determined that some percentage of the water from the frac job that is not recovered may be assisting production by slightly enlarging the mineral structures that adsorb the water. These water-altered minerals may be responsible for propping open small fractures and fissures, increasing the capacity of the formation to flow. Several companies are experimenting with the concept of shutting wells in for extended times after fracturing and before flowback, allowing more leakoff and less total returns. Initial unpublished results appear to be very good with lower decline rates noted when wells are placed on production.

Chemical additives such as surfactants and other surface active agents (soaps, cleaners, foamers, emulsion breakers and other beneficial treating chemicals) are also lost to the formation through adsorption onto mineral surfaces and come out extremely slowly, if at all (Friedmann, 1986; King, 1988; Howard, 2009). These fluids pose little or no risk to the environment since they cannot move, migrate or even release from the formation at higher than part per million levels (Grigg, 2005; Trogus, 1977). Trapped water cannot move from the clay or migrate upward because of the seal rocks at the top of the reservoirs that hold the gas and oil in place.

Reduction of chemicals and substitution of “greener” chemicals can reduce the very small risk even further.

The first fluids to flow from the well are usually the last fluids injected, i.e., the water base of the frac fluid. Chemical content of this backflow is dominated by mixing with reservoir fluids. Salt content in the returning frac fluid may change with the mixing of these waters. First gas may be seen from 2 days to 20 days after fracturing, depending on back pressures, shale system permeability, and flowback design intent (Edwards, 2011).

As gas begins to flow, the rate of water recovery falls rapidly. This will vary slightly between areas, but the general behavior is similar. This rapid drop in water rates at the first show of gas makes it easy to flow the large early volumes of returning water to tanks for the first few days and then switch to through-the-separator flow with much lower water rates as the gas production starts, Figure 23. Interpretation of early time behavior of gas flow is often confused by decisions to hold a back pressure on the system to flatten decline rates and increase recovery, but may also be influenced by pipeline curtailments or high pipeline pressures or gathering system interruptions.



Water Management Issues and Other Sources for Frac Water

Utilizing alternate sources of water for drilling and fracturing to displace fresh water use is a major work area in the industry. The water argument is a complicated issue that requires the oil and gas industry to examine alternate sources. As these have been investigated, a strong economic argument has emerged in many areas for switching from fresh water to salt water based frac fluids.

For simplicity, the water classifications of the Water Quality Association will be used to define descriptive terms.

Table 7: Water Classifications (Source: Water Quality Association, www.wqa.org)

Water Descriptor	Total Dissolved Solids (TDS) in parts per million (ppm)
Fresh	<1000 ppm
Brackish	1,000 to 5,000 ppm
Highly Brackish	5,000 to 15,000 ppm
Saline	15,000 to 30,000 ppm
Sea Water	30,000 to 40,000 ppm
Brine	40,000 to 300,000+ ppm

Produced water from most oil and gas wells is considered a resource for enhanced hydrocarbon recovery through water flooding and formation pressure maintenance. Recovery and reuse of this valuable produced water resource in a closed loop system is both environmentally necessary and typically economically attractive as a water source and as a mineral source (Veil, 2011; Veil 2004).

Water used for shale gas developments includes water for drilling, cementing and fracturing. While fresh water for near surface drilling and cementing is advantageous since the typical leak-off volumes of 1 to 3% will be fresh water, deeper drilling and all fracturing may be able to take advantage of salt water as a base to prevent formation interactions.

Ideally, the salinity content of any water used in an oil or gas reservoir should roughly match the salinity of the fluids already there. Most shales of marine origin have water salinities near that of the sea water when deposited, usually about 35,000 ppm total salinity. Formations in contact with waters in evaporite beds may be higher salinity (Blauch, 2009, Houston, 2009). Use of large volumes of fresh water for fracs in arid areas causes severe problems. Although the average flow rate in a giant river, like the Mississippi (avg. flow of 450,000 ft³/sec – U.S. Army Corps of Eng. Average) would provide the fresh water for the upper range of frac water use for all fracs in

U.S. wells for a year in less than 2-1/2 hours, the local nature of the water draw by the oil and gas industry is what is creating some of the water shortage problem. By switching to a water source in the saline to brine water range and/or adopting closed-loop fracturing water supply where possible, the pressure on fresh water supplies could be greatly reduced, Table 8.

Average volumes, Table 8, of water used per shale well for drilling and fracturing are:

Unconventional Development	Average Fresh Water Volume for Drilling	Average Fresh Water Volume for Fracturing	Average Salt Water Volume for Fracturing
Barnett	250,000 gallons	4,600,000 gallons	
Eagle Ford	125,000 gallons	5,000,000 gallons	
Haynesville	600,000 gallons	5,000,000 gallons	
Marcellus	85,000 gallons	5,600,000 gallons	Increasing
Niobrara	300,000 gallons	3,000,000 gallons	
Horn River (EnCana and Apache)	250,000 gallons	negligible	Up to 12,000,000 gallons

Issues raised in oil and gas industry water usage include total usage of fresh water and the inclusion of salt into fresh water which some believe "removes" the water from the available fresh water resources. The volumes of water used for fracturing are low in comparison to agricultural, municipal, recreation and other industrial use, but large volume well development in an arid area can produce water shortages. In comparison to the energy level used in other energy production techniques, more energy is produced per gallon of water used in the natural gas industry than any other source (Table 6).

Table 9	Range of Gallons of Water Used per MMBTU of Energy Produced
Deep Shale Natural Gas	0.84 - 3.70 ¹
Coal (no slurry transport)	2 - 8
Coal (with slurry transport)	13 - 32
Nuclear (uranium ready to use in a power plant)	8 - 14
Conventional Oil	8 - 20
Synfuel - Coal Gasification	11 - 26
Oil Shale	22 - 36
Tar Sands	27 - 68
Synfuel - Fisher Tropsch (from coal)	41 - 60
Enhanced Oil Recovery (EOR)	21 - 2,500
Biofuels (Irrigated Corn Ethanol, Irrigated Soy Biodiesel)	> 2,500

Water requirements for various energy resources

¹Source: "Deep Shale Natural Gas: Abundant, Affordable, and Still Water Efficient", GWPC, 2010.

²The transport of natural gas can add between zero and two gallons per MMBTU.
Water Use in Deep Shale Gas Exploration - Chesapeake

Water used in fracturing that does not return from the formation is more than offset by the burning of the natural gas. One bcf (billion cubic feet) of gas, about $\frac{1}{2}$ to $\frac{1}{10^{\text{th}}}$ of the gas produced from one shale well will release twelve million gallons of fresh water in vapor form when consumed in home, power generation or other combustion energy generation applications: $\text{CH}_4 + 2 \text{O}_2 \Rightarrow \text{CO}_2 + 2 \text{H}_2\text{O}$.

Although tests from the early 2000 era showed production problems when using higher salinity brines for fracturing shales, the problems encountered then appear to be mostly incompatibility with chemical additives, principally friction reducers. Advances in chemical formulation since then have resulted in friction reducer chemicals that can work in up to 70,000 ppm brines.

The most commonly abundant source of saline waters may be produced waters, including flow-back waters after fracturing. Added sources are natural brine reservoirs that cannot be economically freshened to an agricultural tolerance level. Testing with brine source waters using Debolt formation water (35,000 ppm), by EnCana and Apache in the Horn River Shales appear to have proven successful with a total of nearly 350 fracs with salt water during 2011, and good early well performance.

The oil and gas industry handles about 21 billion barrels (882 billion gallons) of salty water (TDS of less than 10,000 ppm to over 150,000 ppm) per year in combination with the oil and gas produced. According to a study by the Argonne National Laboratory, about 95% of this water is handled through injection with more than half of this water nationally used for enhanced recovery, Table 10.

State	Volume of Produced Water (bbl/yr)			Modified from SPE125999	
	Injection for Enhanced Recovery	Injection or Disposal	Surface Discharge	Total Managed	Total Generated
Alabama	7,500,000	33,000,000	78,000,000	119,000,000	119,004,000
Alaska	1,037,909,000	39,914,000	35,480,000	1,113,302,000	801,336,000
Arkansas	45,489,000	120,169,000		166,011,000	166,011,000
California	1,764,609,000	558,188,000		2,322,797,000	2,552,194,000
Colorado				No data	383,846,000
Louisiana	66,261,000	1,034,092,000		1,149,643,000	1,149,643,000
New Mexico	449,489,000	348,142,000		797,630,000	665,685,000
New York				No data	649,000
North Dakota	64,873,000	65,321,000		134,991,000	134,991,000
Ohio	487,000	6,137,000		6,940,000	6,940,000
Oklahoma	940,272,000	1,254,132,000		2,195,180,000	2,195,180,000
Pennsylvania				No data	3,912,000
Texas	5,011,062,000	2,365,476,000		7,376,913,000	7,376,913,000
West Virginia	3,942,000		3,857,000	8,337,000	8,337,000
Wyoming					2,355,671,000

Many companies are re- evaluating this resource as a cheaper and better base for frac fluid. In areas with developed oil and gas infrastructure, the cost of processing and using this fluid for fracs is both economically and technically attractive as an alternative to scarce fresh water. Common re-processing of produced water seeks to deliver a salt water frac base fluid with from 30,000 to 50,000 ppm TDS, removal or minimization of barium, strontium and iron ions, and removal of chemicals that would compromise the ability of the base fluid to function as a frac fluid for a specific application.

Fresh waters and up to about the salinity of sea water (about 3.5% or 35,000 ppm of predominantly sodium chloride) can be treated with a variety of water treatment technologies to produce drinking water. Cost to produce fresh water depends on the level of TDS and type of ions in the source water. Increasing salt content increases initial cost of treating and cost of disposal of the salt concentrate reject materials. Waters with salinity over about 35,000 ppm, are not considered as economic candidates for creation of fresh water, but are good source waters for fracs.

Treatment for reuse of oilfield produced water in fracturing fluids ranges from no treatment necessary to extremes that would make a particular water uneconomic. Water requirements for a slick water frac vary considerably to that required for a gelled water treatment. Basic requirements for any base water for fracturing include considerations in Table 11.

Table 11: Material to be treated	Level in Source Water	Requirement for Frac Fluid	Treating Methods (focus is on effectiveness and minimum maintenance)
Total Suspended Solids (TSS)	100 to 500 ppm, highly variable	<100 ppm preferred	Settling tank, gas or chemical floc, electrocoagulation, desanders,
Total Dissolved Solids (TDS)	50,000 to 150,000+	Brackish to 50,000 ppm	Dilution with brackish water.
Free Oil (oil carry-over)	To about 300 ppm	<30 ppm preferred	Hydrocyclones, Ozone, aeration, chlorine dioxide, skimmers and separators
Polymer Control	Varying amounts, usually < 250ppm	<100 ppm	Enzyme treatment, flocculant and normal biodegradation steps
Bacteria Control	10 ⁶ to 10 ⁹ cell/ml, of SRB, AFB, SFB, etc.	<10 ³ cells per ml	Ozone, chlorine dioxide, UV, biocides (favor biodegradable if chemicals used)
pH	Varies from ~ 5 to 8	7 to 7.5	Bicarbonate or acid
Iron	100 to 1000+ ppm	<10 ppm	Electrocoagulator, pH increase (ppt),
Barium (not usually present)	10 to 20 typically, higher in a few areas	<20 ppm	Chemical precipitation, electro-coagulator if TSS is high.

Water Treating Options

Water treating options for produced waters are often similar to those used to prepare drinking water from raw fresh water sources, except they do not remove the salinity.

Water treating options vary widely, Table 12, with the choice usually settled by operational concerns and economics (Barrufet, 2009; Blauch, 2009; Blauch 2010; Burnett, 2009; CSM; GE; Gupta, 2009; Hayter, 2004; Klasson, 2002; Rimassa, 2009; Gaudlip, 2008, Funston, 2002).

Table 12	Water Treating Options	Comments
Treating Objectives		
Freshening Salt Brines	Reverse Osmosis (RO), Electrodialysis reversal.	Significant pretreatment required for produced and brackish waters.

Suspended solid removal	Filtration (micro-, ultra- and nano filtration), electrocoagulation, chemical flocculants , sand bed filters and settling tanks.	Stage filtration with backwashable filtration. Excessive solids require early settling/flocculation.
Specific ion reduction	Membrane, electro coagulators, chelating reactions, specific scale development, water softening or ion exchange, etc.	Removal of iron, barium and some calcium is required for frac water reuse.
Radioactive isotope removal	Membrane filters to remove ions with RA character.	Rarely needed, general approach is to keep from concentrating the RA materials.
Toxic Chemical removal	Specific reactants, adsorption, concentration via membranes.	Depends on chemicals – most treating chemicals adsorbed in formation.
Cleaning Frac Flowback for reuse	Electrocoagulation and filters.	Often, just settling is sufficient unless fluids are to be gelled.
Cleaning drilling mud	Forward osmosis (FO) and filtration	FO generates a clear, high salinity brine. Pretreatment often required
Oil removal	Aeration/oxygenation, flotation	Flotation and skimming often very profitable.
Scale prevention	Scale pellet reactors	Effective in some cases, but slow. Ion specific.
Total volume reduction	Evaporating ponds, mechanical low vacuum evaporators	Ponds are slow, mechanical evaporators and usually a last resort.
Bacterial Control	Biocides, UV, nanofilters, chlorine dioxide, chlorination,	Fast changing field, must be economic
Taste / odor/ color	Activated charcoal, some membranes, reactors,	Waste specific, can recycle some

Economics of Shale Wells

Shale wells produce in a different manner than conventional wells and there is considerable misunderstanding surrounding the sometimes rapid declines, stabilizing influences, cost of stimulation and the overall economics of shale projects (Fairchild, 1998; Hill; Hopkins, 1993; Jarvie, 2005; Jenkins, 2008; Lewis, 2007; Mattar, 2008; McDaniel, 2008; Ozkan, 2009; Schepers, 2009; Schweitzer, 2009; Stabell, 2007; Zuber, 1987).

The amount of gas that is contained and can be technically recovered from shales is sufficiently large to attract the attention of most energy companies. Early forays into the Devonian and Barnett shales were promising but not highly economic. During a thirty year period in the Devonian (Marcellus and other shales of Appalachia) and a twenty year period in the Barnett, development of technology was taking place in these fields that paved the way for later completions in numerous shales across North America. Geoscience research on cores and logs identified “sweet spots” within the shales and companies with the latest technology learned where to drill for maximum results. As the learning progressed, shale gas grew from uneconomic or borderline into economic ventures. Multi-thousand well studies (Valko, 2009) have shown that not every company is successful and not every well is economic, but the performance of most shale developments is both economic at the time of drilling and will be steady revenue generators for years to come. An assessment formed in the industry is that about 80% of the early, 2001 to 2007 wells with natural gas price about \$10 per mcf (thousand cubic feet), were uneconomic

in 2011 standards, with gas at less than \$4 per mcf, but the 20% that were economic paid for the rest of the wells twice over. Interestingly, it is the success of the shale developments that have decreased the price for gas and have made some shale wells appear uneconomic.

The production capacity of shale wells is dominated by early “flush” production (rapid flow from “free” gas in larger fractures). This early gas, if handled properly, very often paid for the well within the first year, since these wells often recovered 30% to 50% of their expected ultimate recovery (EUR) during the first year. The production that followed afterwards, although reduced in rate, is highly profitable. Large numbers of these wells build a long term base of stable gas production. Developments in the enabling technologies made the shales progressively more economic (on a stable price basis). It is the application of technologies to find the “sweet” spots in the shale and optimize development costs that separate successful shale players from those who are not.

Impact of Technology

Shale developments are made possible by development and application of technologies, both in engineering issues and environmental issues. Technology developments, when compared with increased recovery of gas and oil from the shales, show the impact of innovations and adaptations in a much clearer light. The environmental challenges also enter this matrix and actually dominate the future stages of development, Table 13.

Table 13: Technology Development Impact on Original Gas In Place (OGIP) Recovery from Shales

Year	% OGIP Recovery (OGIP = original gas in place)	Technologies Applied	Shale in Development	Average gas price \$/mmbtu
1980's	1%	Vertical wells, low rate gel fracs	Devonian	\$1.98
1990's	1.5 to 2%	Foam fracs 1 st slick water in shale	Devonian	\$1.91
2001	2 to 4%	High rate slick water fracs	Barnett	\$4.25
2004	5 to 8%	Horizontal well dominant, 2 to 4 fracs	Barnett	\$6.10
2006	8 to 12%	Horiz, 6 to 8 fracs, stimu fracs, water recycle trial	Barnett	\$7.25
2008	12 to 30%	16+ fracs per well, Petrophysics increases	Barnett	\$9- drop
2010	30% to 40%	Technology to flatten decline curve, feeling pinch for frac water	Haynesville	\$4.20
2011	45%+	Pad development drains 5000 acres, salt water displacing fresh for fracs	Horn River	\$4.00
Future	project 45 - 55%	Green chemicals, salt water fracs, low disposal volume, reduced truck traffic, pad drilling, electric rigs and pumps	Numerous	Depends on market

This early high failure rate and extreme profitability of a minority of the wells has driven technology to improve early investigations and improved completion practices.

Are Seismic Events linked to Fracturing or Disposal Wells ?

Seismic events are extremely common, from the slightest sounds of rock breaking and dislocating a few millimeters during geothermal energy production, hydraulic fracturing and deep-shaft mining, to major earthquakes driven by continental plate slippage that rips open hundreds of miles of natural faults. Since 1900, the USGS data shows that the number of damaging earthquakes has remained constant. There appears to be no connection between hydraulic fracturing and damaging earthquakes, although fracturing into a moderate sized fault may produce seismic energy sufficient to be measured by near-by instruments.

Several million earthquakes occur in the world every year. Roughly 150 damaging quakes per year of magnitudes of 6.0 and higher are recorded, while about 10,000 quakes are felt but produce no significant damage and about 1.5 million quakes are recorded or estimated but are not felt (USGS Earthquake Facts and Statistics).

Hydraulic fracturing produces measurable signals when the instruments are very close to the frac. Fracturing energy signals have a range of measured moment magnitude of -4.0 to -1.0 in non-faulted environments and measured magnitudes of up to about -0.5 when a frac engages a typical formation fault (see Figure 25). In comparison, a 6.0 earthquake has 31 billion times more energy release than the -1.0 high-end energy level of the frac and one billion times more energy release than the -0.5 level of fracturing into a fault (USGS Magnitude comparison calculator). A damaging 6.0 quake releases 1000 to 31,000 times more energy, respectively, than the typical 4.0 to 3.0 “felt” quake.

From USGS: “An *earthquake* is what happens when two blocks of the earth suddenly slip past one another. The surface where they slip is called the *fault* or *fault plane*. The location below the earth’s surface where the earthquake starts is called the *hypocenter*, and the location directly above it on the surface of the earth is called the *epicenter*.”

From the USGS Facts and Statistics website, there are several million earthquakes a year worldwide, Table 14, with very few stronger quakes. The number of earthquakes above a magnitude 6 (damage producing quakes) have been constant for years. Very small earthquakes (magnitude 1.9 and less) are very difficult to record since the earth appears to damp out the small signals in a mile or less.

There have been links established between earthquakes and oil and gas activities such as deep well disposal of some produced water (Arkansas, 2011; Frohlich, 2010) as well as injection of other fluids such as military wastes (Rocky Mtn. Arsenal Deep Injection Well Fact Sheet) and the large volumes of water injection encountered in geothermal energy production (Harmon, 2009). Most of these events have involved extremely large, continuously injected volumes (many times frac volumes) and at much deeper injection points. There is a direct link where the disposal involves deep disposal wells near or in large active faults.

Table 14 Earthquake Facts and Statistics

Frequency of Occurrence of Earthquakes

Magnitude vs. Ground Motion and Energy

Magnitude	Average Annually
8 and higher	1 [*]
7 - 7.9	15 [*]
6 - 6.9	134 [*]
5 - 5.9	1319 [*]
4 - 4.9	13,000 (estimated)
3 - 3.9	130,000 (estimated)
2 - 2.9	1,300,000 (estimated)

Magnitude Change	Ground Motion Change (Displacement)	Energy Change
1.0	10.0 times	about 32 times
0.5	3.2 times	about 5.5 times
0.3	2.0 times	about 3 times
0.1	1.3 times	about 1.4 times

This table shows that a magnitude 7.2 earthquake produces 10 times more ground motion than a magnitude 6.2 earthquake, but it releases about 32 times more energy. The energy release best indicates the destructive power of an earthquake. See: [How much bigger is a magnitude 8.7 earthquake than a magnitude 5.8 earthquake?](#)



^{*} Based on observations since 1900.

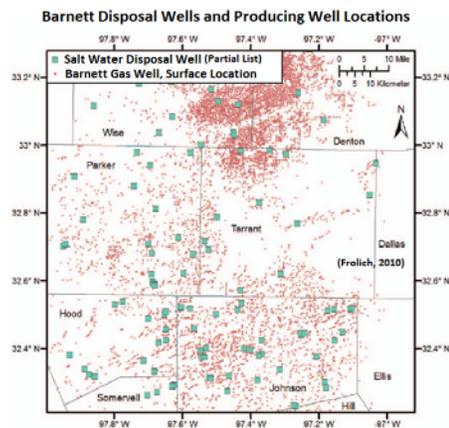
These numbers have been recently updated, based on data from the [Centennial catalog](#) (from 1900 to 1999) and the [PDE](#) (since 2000).

^{*} Based on observations since 1990.

The USGS estimates that several million earthquakes occur in the world each year. Many go undetected because they hit remote areas or have very small magnitudes. The NEIC now locates about 50 earthquakes each day, or about 20,000 a year.

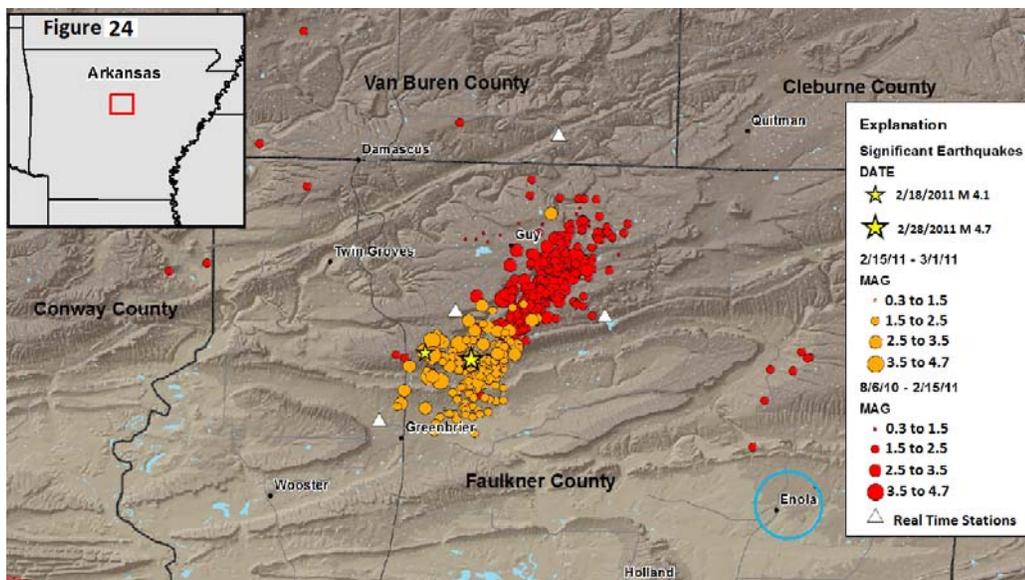
As more and more seismographs are installed in the world, more earthquakes can be and have been located. However, the number of large earthquakes (magnitude 6.0 and greater) has stayed relatively constant.

Sporadic small seismic tremors of magnitude 2.0 to 3.9 have been reported for several years in and around the Ft-Worth area during the development of the Barnett Field. A very detailed study by the University of Texas and Southern Methodist University (Frohlich, 2010) examined a series of eleven well recorded but “non-felt” events with magnitude less than 4.6 in the vicinity of the DFW airport. The hypocenters of these quakes was 4.4 km deep (2.7 miles or 14,400 ft), which is considerably deeper than the near 7,000 ft depth of the Barnett field and fracturing in this area, but nearly at depth of the injection wells in the area (3.3 to 4.2 km, or 10,752 to 13,729 ft.). One finding of the study was that one of the SWD (salt water disposal) wells was potentially engaging a fault at a similar depth to the injection point and less than 1 km (0.62 mile or 3273 ft.) from the well’s injection point. The study also points out the other 200 salt water disposal wells in the Barnett area, including some with locations within a few thousand feet of this example, have not produced seismic events.



“There are thousands of deep disposal wells (solely for produced water) in Texas, the vast majority of which produce no felt or instrumentally recorded seismicity” (Frohlich, 2010).

The area with the most recent information on earthquake swarms is near Guy, Arkansas, Figure 24, nearby but not adjacent to the New Madrid Fault line (USGS; Geology.com, 2011; Rabak, 2011). Several thousand small quakes, the vast majority of which are not detectable except with near-by seismic instruments, have occurred from 2010 to mid-2011.



The area just southeast of Guy, near Enola Arkansas was the site of two previous earthquake swarms of thousands of small quakes in 1980 (30,000 earthquakes in a three year period) and again in 2001 (2500 in two months). Both of these previous swarms predate drilling, fracturing or deep well disposal in the area.

The epicenter of the 2010/2011 Arkansas quakes were at a hypocenter or focus depth of 6,600 ft to 26,400 ft (productive Fayetteville shale depth is at 3,000 to about 6,000 ft in the area) and disposal wells are at about 12,000 ft. The Arkansas Oil and Gas Commission pinpointed four deep disposal wells in Central Arkansas that lie near a previously unknown fault system and ordered closure. When two of the four disposal wells ceased operations in March 2011, the number of quakes of greater than 2.5 magnitude dropped from 85 in the 18 days before closure to 20 in the 18 days after injection well closure. The commission issued a moratorium on new injections wells in an 1100 square mile area over the fault system. Fracturing continues in the area without a link to the sporadic earthquake activity.

Hydraulic fracturing related creation of a moderate magnitude earthquake (magnitude greater than 5) in an unknown fault system is a very remote possibility because of the generally low incidence of quakes after or during fracs and the ease of spotting larger faults on 3D seismic surveys. Hydraulic fracturing may be able to create small fault slippage and thus very small tremors that are at or usually well below the “felt” threshold. Gas storage reservoirs that exposed to fast charge and discharge rates (movement rates of hundreds of hundreds of millions of scf (standard cubic feet) to a bcf (billion cubic feet) per day have had long-term studies of rock movement and micro-tremors (Deflandre, 2002).

The magnitude of an earthquake is related to the length of the fault on which it occurs; the longer the fault (or the activated portion of that fault), the larger the earthquake. The more extensive faulted areas should be investigated with 3D seismic to assist in placing wells in the best potentially productive areas and avoiding significant faults. Some evidence exists for small faults to jump barriers but still remain small quakes. Most shale pay zone faults are a few hundred meters long and do not have the potential, even with large volume fracture fluid injection, to create much more than a small measured or, in rare cases, a low magnitude “felt” earthquake.

A few major earthquake examples (from www.earthquakecountry.info and USGS).

- Largest earthquake in 1960, Chile, 9.5, ruptured entire 1000 mile fault.
- Largest earthquake in US, 1964, Alaska, Magnitude of 9.2, Ruptured 620 miles of 2240 mile fault.
- “Great Earthquake” San Francisco, 1906 was 7.7 to 8.2, ruptured 250 miles of 800 mile fault.

- Virginia Earthquake of 23 August 2011. Magnitude 5.8, location 37.936°N, 77.933°W, depth 19,600 ft. (6 km), In the midst of several deep, identified faults. (no current oil or gas operations were located within 100 miles of the epicenter)
- Largest earthquakes for selected states are shown in the USGS table:

Table 15 Max Magnitude Earthquake by State

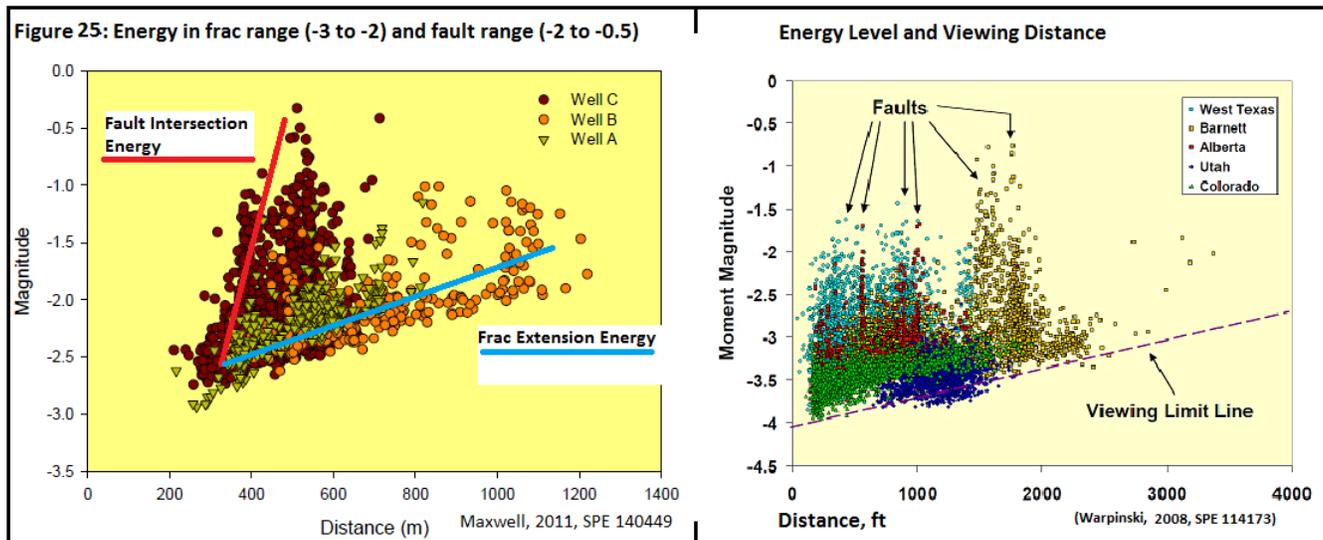
State	Date	Latitude	Longitude	Magnitude
Alaska	1964 03 28	61.04N	147.73W	9.2
Arkansas	1811 12 16	35.6N	90.4W	~7.7
California	1857 01 09	35.7N	120.3W	7.9
California	1906 04 18	37.75N	122.55W	7.8
Colorado	1882 11 08	40.5N	105.5W	6.6
Louisiana	1930 10 19	30.0N	91.0W	4.2
Montana	1959 08 18	44.712N	111.215W	7.3
New Mexico	1906 11 15	34.0N	107.0W	
New York	1944 09 05	44.958N	74.723W	5.8
North Dakota	1909 05 16	49.0N	104.0W	5.5
Ohio	1937 03 09	40.470N	84.280W	5.4
Oklahoma	1952 04 09	35.525N	97.850W	5.5
Pennsylvania	1998 09 25	41.495N	80.388W	5.2
Texas	1931 08 16	30.502N	104.575W	5.8
Virginia	1897 05 31	37.3N	80.7W	5.9
West Virginia	1969 11 20	37.449N	80.932W	4.5
Wyoming	1959 08 18	44.699N	110.705W	6.5

USGS - Largest Earthquakes by States

- Note that all of the largest quakes pre-date the development of shale gas production and many predate the inception of fracturing in conventional wells.

Hydraulic fracturing does produce some energy releases in the formation that are similar to those produced by earthquakes, but significant differences are noted in the frequency and magnitude that allow differentiation of the small magnitude sounds of shear fracturing and the sounds of even the smallest earthquake. The measurement of micro-acoustic energy generated during hydraulic fracturing (shear fracturing) registers magnitudes of about -3 to -1 on the open ended (logarithmic) Richter scale, Figure 25. The points in the -1.0 to -0.5 range (far upper end for hydraulic fracturing) were recorded in a study on frac penetration into a known fault.

This type of energy generation can easily be seen in micro-seismic and fracturing where the recorded events plots significantly differently than those from earthquake related energy.



In comparison to small earthquakes in the Guy Arkansas area (the maximum magnitude was 4.7), microseism magnitudes generated during fracturing (measured with downhole equipment), are at a comparison level of 50 million times less (than the 4.7 magnitude quake) for a microseism magnitude of -3, to a half a million less when magnitude is -1. (USGS calculator <http://earthquake.usgs.gov/learn/topics/calculator.php>)

Risk Reduction – Run 3D Seismic or other mapping method capable of locating faults with a throw of 50 to 100+ feet and select well locations that stand off a sufficient distance to avoid activation of major faults (those of significant length). Fracture direction should be known and well placement should avoid the faults. Very small faults are not a concern.

Mitigation - Recognition that a frac has entered a fault by microseismic or pressure response is a decision point. Continued injection into a fault of significant size may not be beneficial to production and can, in rare cases, be potentially problematic on a number of levels if very large volumes are injected. Small faults do not appear to be a problem and may hold significant gas reserves, however, more knowledge is needed about local geology.

Methane Contamination in Fresh Water Wells

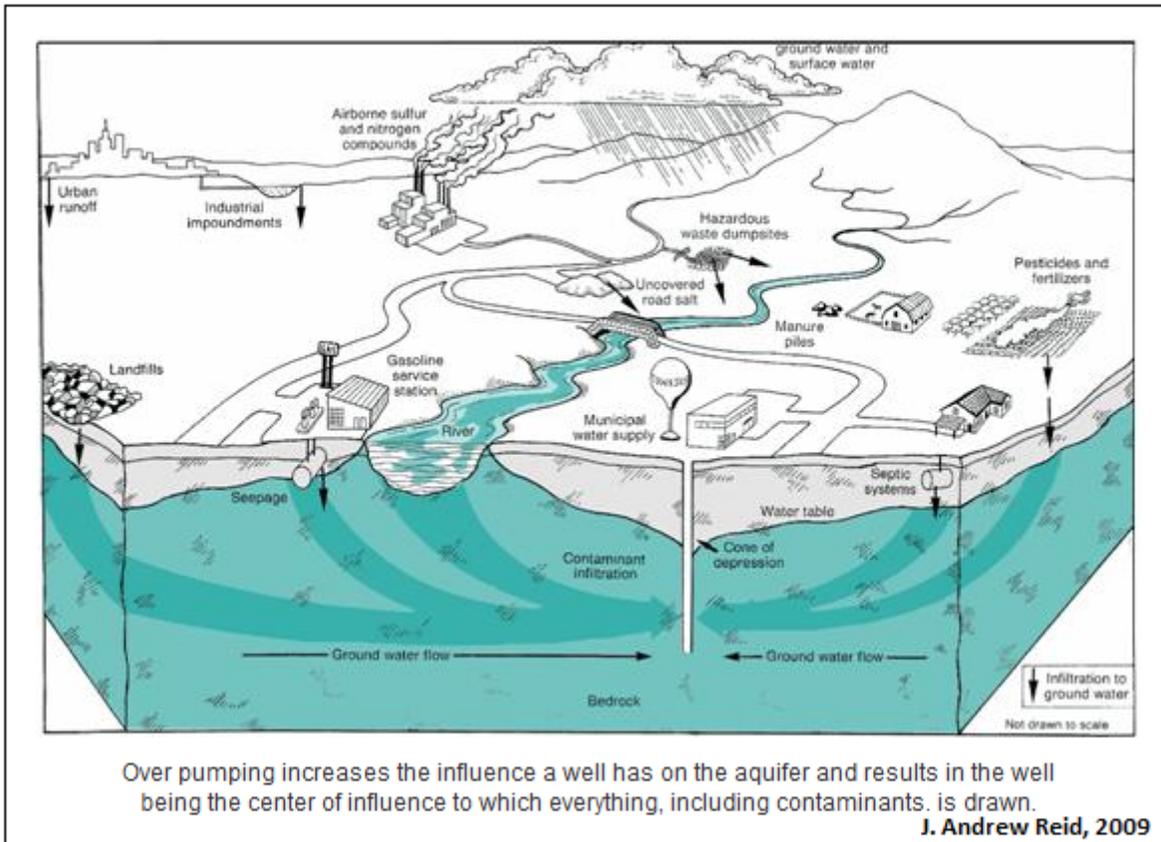
Many fresh water wells produce some level of odorless methane. Sources of methane in areas with no drilling activities include agriculture, livestock, wetlands, landfills and other sources where biogenic gas is generated from decaying or digesting vegetation. Seeps may contribute biogenic or thermogenic gas. Biogenic gas is nearly 100% methane with an occasional trace of ethane. Natural biogenic sources emit about hundreds of mcf/d of methane in the US according to the EPA (EPA, 2010). Thermogenic gas will contain methane and often 8% or more of C2 to C5+ ranges of the heavier gases and lighter oils. Thermogenic methane is also distinguishable from biogenic methane by testing the carbon isotopes.

Other water well sources of methane that may increase over time include water wells that have penetrated coal formations that are saturated with fresh water. Many coals contain enormous amounts of methane gas adsorbed onto the organic coal surfaces. Coal bed methane gas production wells access this gas supply by pumping the fresh water off the coal, allowing the methane to desorb and be produced. In fresh water supply wells that access water in shallow coal seams, methane content will rise as water is withdrawn if withdrawals outstrip the recharge rate. All sandstones and carbonates have methane adsorbed on organic materials within these rocks, but much less total methane content than coal. Withdrawing water in these formations will result in a rise in methane production in the water phase.

Many water wells in the US are poorly regulated and managed. The most frequent cause of well problems is in actually using the well too much – over producing or over drawing the water well's recharge rate. The action of using water faster than it can be replenished near the wellbore or in the aquifer in general, creates an access point for surface pollutants of many types. The sketch in Figure 26 is a simple but useful description of the problems.

Water wells should be located beyond the influence of septic, runoff, spill zones, and industrial operations of any type. Water well construction should feature adequate isolation with pipe and cement. Withdrawal should be matched to recharge rate.

Figure 26: Effect of Fresh Water Well Drawdown that is Higher than Replenish Rate (<http://www.wellmanager.com/wellmanager-environment.htm>)



Risk Reduction – sample water wells in the area (within $\frac{1}{2}$ mile of the well to be drilled) if possible and map methane seep areas or natural flow paths and decide on methods of avoiding active seep paths (if present) if fracturing is planned. Evaluate gas show logs and determine if fracturing is immediately necessary for economic production.

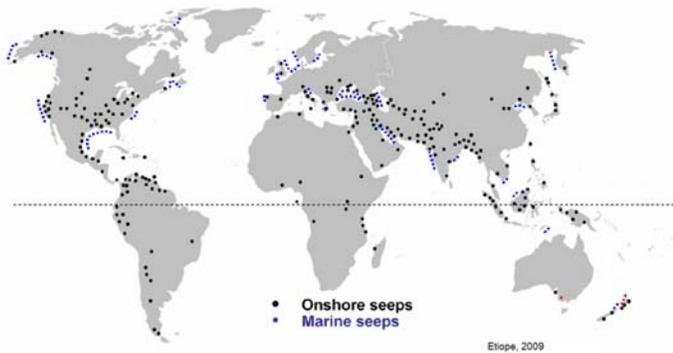
Mitigation – Check cement coverage and leakage with noise logs and repair cement if problems are found. Noise logs are normally useful for locating moderate to large wellbore annulus leak paths in gas wells. Other channel leak detection methods are available (Blount, 1991). Natural flows of methane (unconnected with drilling or fracturing activities) are very common, especially near shale or coal outcrops. A methane vent on the well is usually adequate for very small flows as these usually diminish or disappear in a few weeks (Keech, 1982). Methane recovery may be economic in larger flows. Most natural methane seeps are relatively steady in appearance of gas, but gas rate can be episodic.

Natural Seeps of Oil and Gas: Effect on Pollution and Effect of Fracs and Wells on Seeps

There are literally thousands of natural oil, gas and salt water seeps that come to the surface, both on-shore and off-shore (Etiopo, 2009; History of Natural Seeps in Northern San Juan County; Natural Gas Seeps in Santa Barbara; Quigley, 1999; Corthay, 1998; USGS web site on seeps). The earliest historical written record of natural oil and gas seeps in the western hemisphere was that of Sir Walter Raleigh's account of the Pitch Lake in Trinidad in 1595. In 1632, a Franciscan wrote of the oil springs of New York. Canadian First Nations used bitumen from the Athabasca oil sands to waterproof their birch bark canoes. A Finnish scientist reported and mapped the "oil springs" of Pennsylvania in 1753; probably the same ones that Edwin Drake followed to drill the first US oil well in 1859. On the west coast, there are literally thousands of oil seeps in California including McKittrick Tar Pits, Carinteria Tar Pits and the La Brea Tar Pits. Early oil explorers used the seeps to locate potential oil sources. Many of these seeps have stopped flowing since drilled wells have produced the oil below the surface and lowered the driving pressure of the seep. The world's largest oil seep is the Coal Oil Point seep

in the Santa Barbara Channel in Southern California (actually a collection of dozens of submarine seeps). Oil and tar from this seep, which was used over 1500 years ago by local Chumash people, currently flows about 5,000 to 6,500 gallons of oil and nearly two million standard cubic feet of gas per day, but this current flow rate has diminished significantly over the past 20 years as the nearby Ellwood field has decreased the reservoir pressure in this section of the Monterey formation.

Crude oil and natural gas are natural products produced by thermally induced decay and modification of organic particles by historical burial and temperatures adequate to drive the maturation reaction. The heat and time change the organic material laid down with sediments from its organic state (algae, plant, marine animals, etc.) to oil and gas. The rock and marine sediments accumulated over many millions of years vary in composition from shales to sands to carbonates. The sequential deposition of rock layers formed millions of potential reservoirs, seals and traps that still retain perhaps up to half the oil and gas originally generated, the remainder having escaped to the surface where it was digested by colonies of bacteria and other single cell animals or oxidized by various reactions that consume oil. The escape of hydrocarbons to the surface continues today, propelled by pressures in the buried reservoirs along faults, and unsealed, low permeability channels to surface as natural oil and gas seeps. Literally thousands of land and subsea oil and gas seeps circle the globe, marking near-surface deposits and paths of oil and gas. Major areas of oil and gas creation are usually heavily marked by presence of natural seeps, Figure 27.



Small gas seeps are known throughout Appalachia, wherever shale outcrops or nears the surface, Figure 28.



Figure 28: YouTube Photo of the “Eternal Flame”, Shale Creek Preserve, Chestnut Ridge Park, New York State, Photo by Jessica Beal.

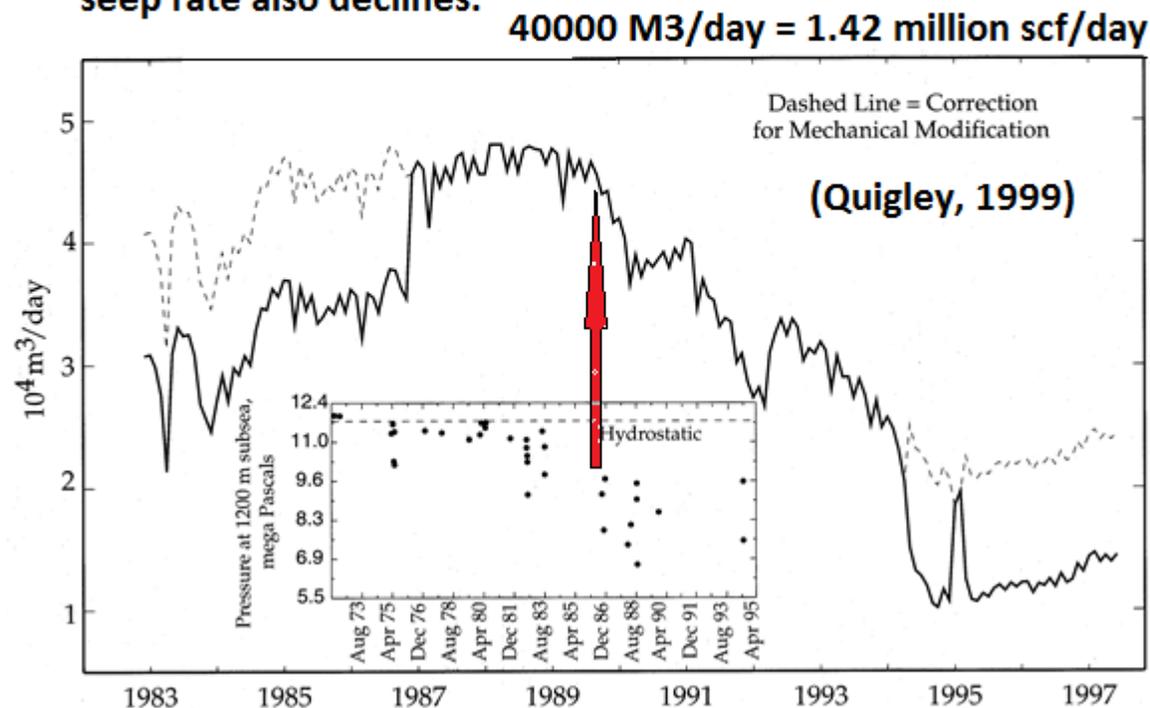
Not all gas seeps are natural and shallow wells can have an impact on seep rates.. The USGS and state geological societies investigate seep activities before and after well and coal mine development and some seeps are influenced, as a decrease or increase in methane emissions, by drilling and mining activities. USGS defines a seep as “a place where fluids, such as water, petroleum, or natural gas emanate from the Earth’s surface. Most

seeps are natural, but in some unusual circumstances man-made activities can create new seeps or change the rate of flow of natural seeps (Fassett, 1997).

The typical response, seen in shallow coals, shales such as the Monterey (California) and other formations, is to decrease the output from the seep by lowering the reservoir pressure and producing what would have seeped.

The exact amount of oil and gas emerging from these seeps is difficult to predict exactly since some of the smaller seeps are sometimes episodic in nature. In the Coal Point Seep area, tents over the offshore seeps have trapped some of the gas, allowing a test of the effect of wells producing from the reservoirs that feed the seeps. Figure 28, shows gas seep output measurements and the effect on the seep rates of reducing reservoir pressure through gas well production.

Figure 29: Changes in Natural Seep Output due Production
Dashed line is a correction for seep tent area change
Inset shows pressure decline in Holly reservoir from 1973 to 1995 - note that as reservoir pressure starts to decline, the seep rate also declines.



On the gas side, from a world-wide perspective, about 10 to 15 bcf of methane is estimated to be naturally vented by seeps and wetlands each day.

Risk Reduction – see the section on locating abandoned wells, which has information on locating both natural and man-made methane seeps.

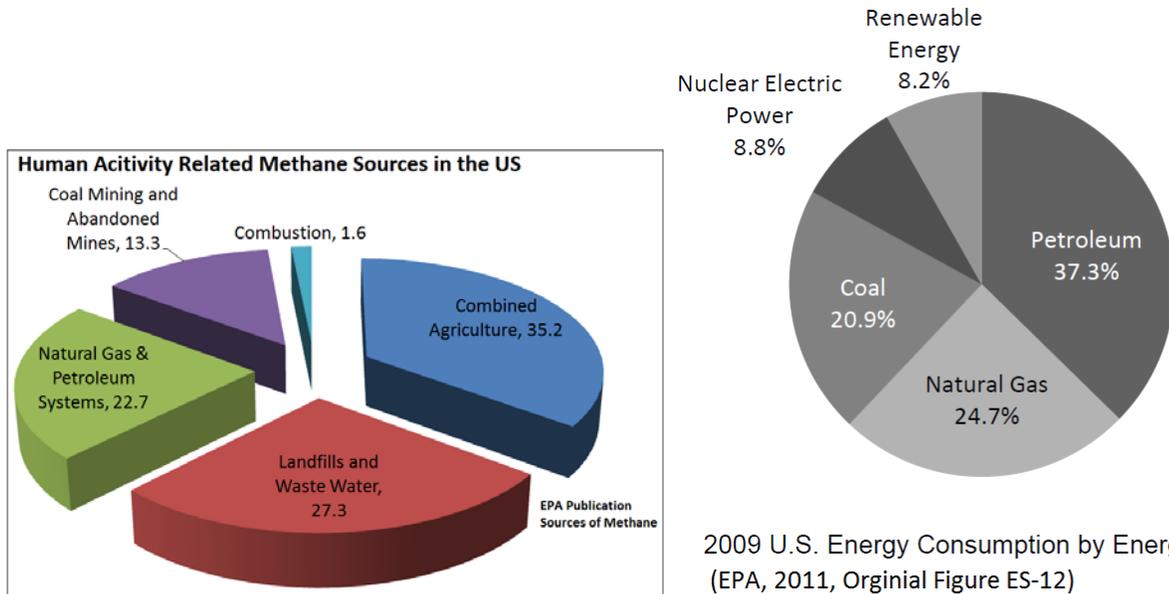
Mitigation – few treating methods will resolve an increase in seep rates, although the overwhelming experience is a reduction in methane seepage when wells are drilled and actively produced in the area. Good cement isolation is essential through areas of seeps and a longer cement column than normal may be necessary.

Emissions from Production and Burning

Emissions from gas production come from direct emissions (methane venting during frac cleanup, lost gas or fugitive emissions and CO₂ from natural gas fuel combustion), and indirect emissions from trucks, pumpers and processing equipment used in drilling, fracturing and production. Although gas is a very clean burning, low emissions fuel, the emissions from fugitive emissions and the supporting diesel pumpers and trucks remains a

problem. Current research in replacing all or part of the diesel fuel with natural gas is being pilot tested in a number of places, but the fastest way to reduce emissions is to minimize water hauling truck traffic and transfer water with pipelines.

For reference, Figure 29 shows the approximate methane emissions for a number of human activities and energy sources in 2009.



Interestingly, the wedge of methane emissions accountable to natural gas operations is larger than coal, but gas produces roughly $\frac{1}{2}$ of the CO₂ as coal when burned. Of the four major methane gas contributors, gas is the only one from which methane emissions can quickly be brought under control by changes in well development operations. Note also that the methane emissions are a total from both gas production and oil production.

The biogenic sources of methane from agriculture, landfills and waste water treating are mixed gases that require significant treating to effectively separate and use, while the methane emissions from coal present a significant challenge to collect even a low grade fuel, often only a few percent in air at any time.

The 2009 U.S. Energy Consumption by Energy Source (EPA, 2011) shows a clear picture of methane usage as fuel, compared to other sources.

Abandoned Wells

Well abandonment has been tightly regulated for only about the last 60 years. Leaks from improperly abandoned and orphaned wells have been frequently traced to contamination of fresh water although fracturing is not implicated in the investigations. Many, if not most of these leakages occur from wells drilled and abandoned before the advent of hydraulic fracturing. Prior to the enactment of tested and monitored plug and abandonment legislation by the producing states, abandonment of non-flowing wells was at the whim of the operator. Most of these dry holes were plugged by an assortment of methods, most of them not considered permanent by modern standards. Most of the older, shallower wells pose a risk of fresh water contamination from the surface contaminants or seeps of formation brine to the surface. While deep well fracturing is not known to play a common role in connecting into these predominantly shallow wells, the risk that does exist can be minimized by an abandoned well survey before leasing or drilling.

Most US oil pay zones of 60 to 150 years ago were on the order of less than 100 ft to 2400 ft. Most newer wells, and especially the shales, are typically at depths of 3,000 to 12,000 ft. Improperly abandoned wells are more of a potential hazard for increasing fracturing risk if they are close to the new well (~1000 ft), in the primary fracture direction and are drilled to a similar depth.

Properly abandoned wells with cement and mechanical plugs set according to regulations and accepted engineering requirements are not a threat to water supplies, even if they are intersected by a fracture treatment from a deep well. Barriers and seals, both natural and added mechanical stops, are suitable for preventing communication to upper zones even at fracturing pressures.

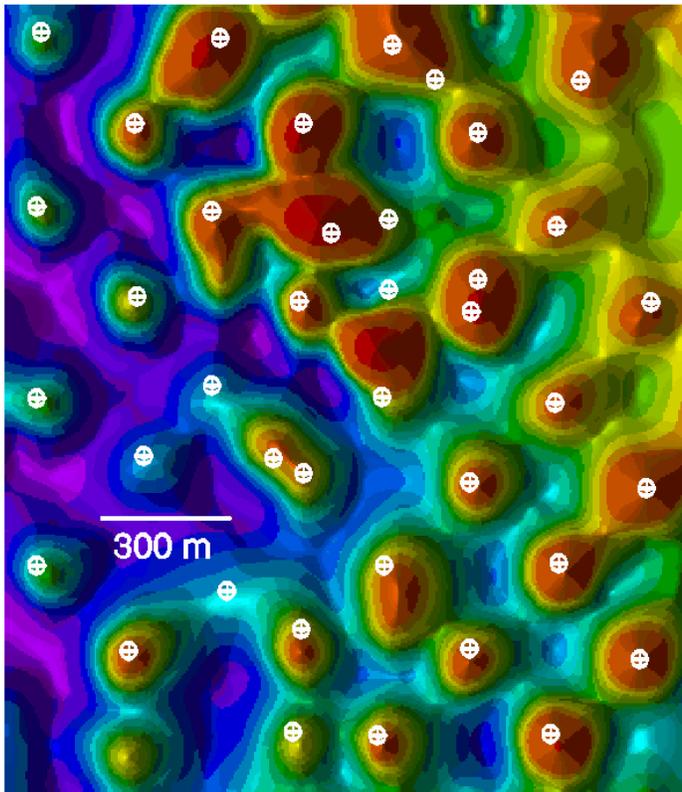
An abandoned well interference assessment should be part of the early exploration phase, possibly even before leasing is finalized or site preparation is started. Locating wells and even brine plumes migrating through the rock strata can usually be found by one or more of a set of usually inexpensive methods (Jordan, 2002). The technology was developed for assessing gas storage safety potential for regulated gas storage reservoirs and storage caverns, both of which operate at high pressures and frequent injection and withdrawal activities. The assessment follows a set protocol of checks including:

- Assess geological potential for migration: permeability, porosity, faults, geologic unconformities (traps and redirects), outcrops (potential vents), and hydrocarbon properties (viscosity, phases, etc.).
- Wide area surveys, including historical records and photos (old wells and sites), record of deep mines, corrective well actions (repairs and recompletions), and aerial or satellite surveys (Hammack, US DOE). These techniques quickly eliminate areas of low risk and concentrate efforts on high risk areas.
- Remote sensing when required (old locations suspected but not located), including aero or land magnetic surveys, infrared photography, ground penetrating radar, spatial pattern analysis, modified topography recognition, vegetation age changes and vegetation stress (locates brine and oil natural seeps).

An example of magnetic survey use in a known field is shown in Figure 30. This USGS photo is of an old field in Oklahoma with the well locations marked on top of the ground magnetic highs and lows. Such surveys can be run by the USGS or commercial services. Thermal and infrared photography are useful for locating natural gas seeps.

Magnetic Surveys for Locating Abandoned Wells

Figure 30



Abandoned and unrecorded wells may act as conduits for the contamination of groundwater supplies by oil field brines and other pollutants.

Carefully designed ground magnetic or aeromagnetic surveys can be used to locate abandoned wells by mapping the magnetic disturbances or "anomalies" produced by their steel well casings.

The U.S. Geological Survey (USGS) can, at the request of other Federal, State, or local agencies, conduct, process, and interpret such surveys, or it can aid in the design and monitoring of contracts for such surveys.

Red shades indicate high magnetic field values: blue shades indicate low magnetic field values. White symbols represent wells located on aerial photographs. The aeromagnetic data have been corrected for latitude-dependent effects under the assumption that all induced magnetization is parallel to the regional magnetic field.

USGS Fact Sheet 163-95

Figure - Color shaded-relief total field aeromagnetic map over part of the Coon Creek oil field near Arcadia, Oklahoma.

After surveys of old wells, predrill investigation usually includes examination of the 3D seismic to select safest well path. Other considerations are abandoned mines, active wells, and specific major avoidance areas such as gas storage areas.

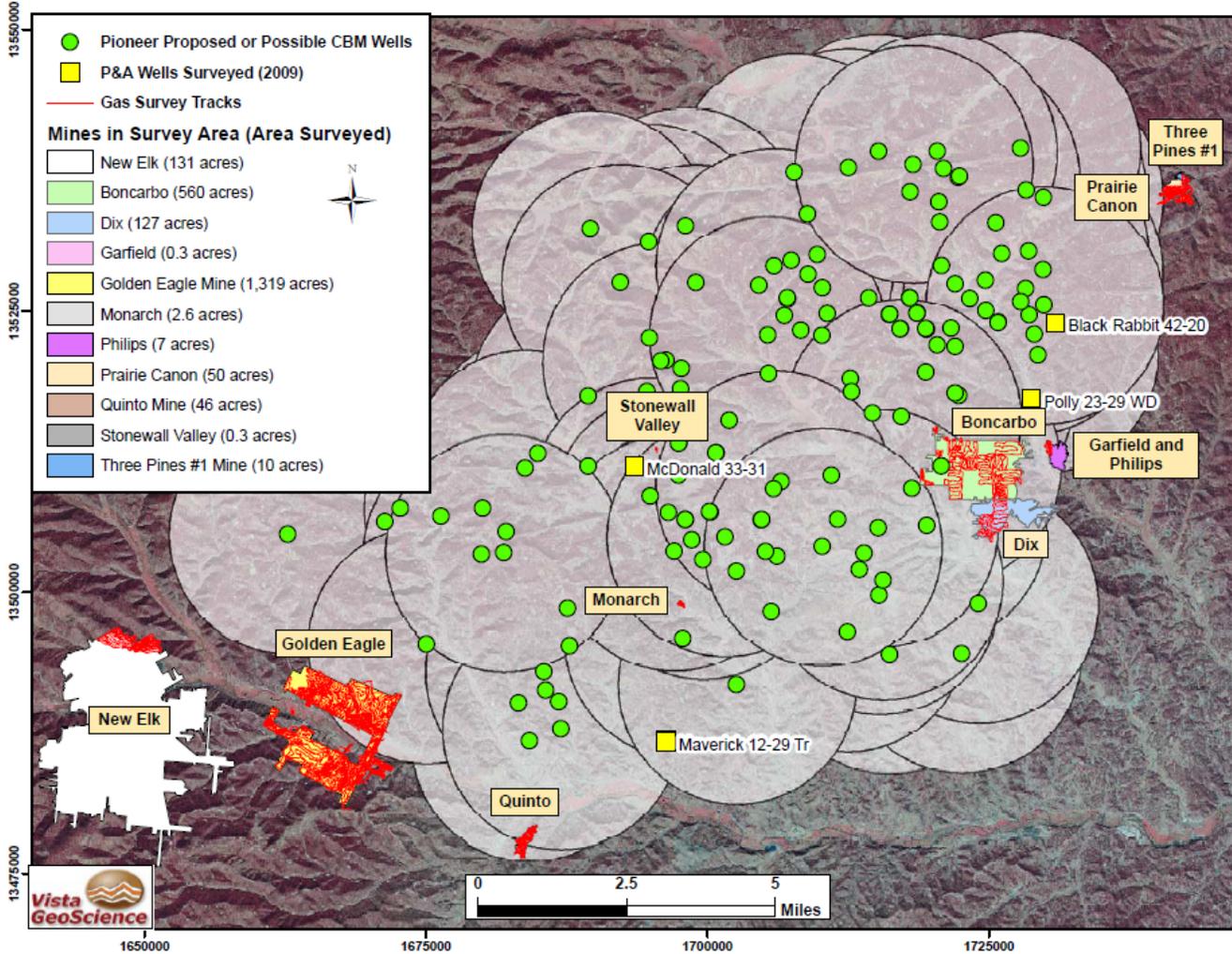
Figure 31 shows a predrill investigation that lists abandoned wells, high soil methane (water well testing needed before drilling), and coal mines (Senseshen, 2010). This type of investigation, along with searches for unmarked abandoned wells is critical to avoid several risk scenarios.

Figure 31 : Pre-Drill Survey of abandoned wells, mines and coal seeps.

vista Project No. 9041.01
Pioneer Natural Resources, Inc.

COGCC Rule 608 Soil Gas Survey Report
Las Animas County, CO

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Coal mines within the 2-mile buffer of proposed or possible CBM wells and P&A wells within ¼ mile of the wells. The New Elk mine is in a 2-mile buffer of new CBM wells proposed by Pioneer in mid-2010.
Senseshen, 2010

A Risk Matrix for Well Development Activities Involved in Fracturing

Risk is generated by uncertainty of the outcome of an action (Holton, 2004). The elements of risk as it is applied here consist of probability (belief that a detrimental event can occur and that a frequency can be predicted for that event) and severity (or impact) of that event. The fracturing transport probability is as simple as using insurance tables on wreck frequency, fuel spills, truck roll-overs and some equipment failures where reliability data exists.

Potential pollution from the specific act of fracture pumping is not an easy prediction to make since the bulk of the evidence for actual cases of pollution is negative and the documentation of claimed detrimental results are absent or discounted by scientific and engineering investigation (Jackson, 2010). This creates significant uncertainty

around the unmeasured or un-measurable part of any impact of pollution from the specific act of fracturing. Unfortunately that is the best we can do with the available scientific information.

Where solid information is not available, a “worst case scenario” was made by imagining a route of transfer (cement channel, breach of casing, etc.) and calculating the amount of frac fluid and the associated chemical in that fluid that could possibly be lost during the frac job via that flow route in the time of the average fracturing stage (assumed average 3 hours). Monitoring (a low side risk differentiator) was envisioned to lower the probability and/or the impact by decreasing or eliminate the frequency of an event occurring and/or to minimize the impact.

The following is a hazard analysis which, when combined with a probability estimation, will produce risk estimates for the various activities in fracturing for potential of ground or surface fresh water contamination. The main fracturing activity studied will be slick water hydraulic fracturing in shale formations. The pollution potential will include examination of pollution routes for frac fluids, chemicals, returned fluids, unreturned fluids, seismic disturbances, natural seep alteration, penetration of aquifers by fracs and emissions from fracs. Water sources specifically protected from contamination include fresh and brackish water aquifers (refer to Table 3); sources that are suitable for economic levels of treating to make drinking water. The objective is to identify high risk elements of fracturing activities and to assign appropriate risk reduction actions.

Context: The first action in this study is to separate well construction issues from fracturing issues. Well construction issues, specifically the design, supervision, application, testing and monitoring of well construction, are influenced by a company’s design philosophy and commitment to a sound design. Any well activity that begins with a sub-standard well will likely fail, regardless of the quality of the well activity. The root cause of problem would be the well construction, not the well activity.

Fracturing issues, defined here as the transport of fracturing materials to the well, the specific act of fracturing, the recovery of frac fluids from the well prior to production and the transport of fracturing materials from the well, offer similar base-line impact and probability, regardless of the operator, given adherence to lawful and safe operational practices. Reduction in base-line impact and probability comes from a company’s commitment to use and optimize practices that reduce the impact of the event and/or the probability of the event.

A separate risk analysis would be needed for drilling, production, abandonment, and other operations.

Variances in local transport incident occurrence and local geology necessarily make a hydraulic fracture risk evaluation a local analysis. There cannot be a single detailed over-all frac risk analysis. General analyses can be constructed but the user must specify a range of occurrence suitable for the areas to be compared. Many of the factors discussed will be further influenced by the operator’s experience, geological and engineering skill, ethics and projection of well design life and well functions during that life.

For purposes of maximum usefulness, this matrix will apply for a multi-stage fractured horizontal well using slick water fracs and minimum chemicals associated with current slick water fracturing application. Total volume of the frac fluid used on one well will be five million gallons (reference Table 4) in ten total stages and four million pounds of sand will be pumped with the fluid.

Local variances include:

- Traffic wreck incidence frequency, from state-to-state and road types from 2-lane rural to controlled access interstate.
- Transport design type – double hull and compartmentalized vessels used for fuels vs. single wall tanks used in fresh water transport.
- Transported material type – fresh water, salt water, diesel fuel, dry additives, liquid chemical additives and sand, all pose different environmental impacts. Fluids in transport may have about the same spillage frequency, but vessels hauling the loads will be designed differently and may be regulated differently.
- Toxicity and biodegradability of the spill – the risk posed by the material should determine the level of safeguard taken; i.e., low for fresh water, higher for diesel, highest for persistent (non-

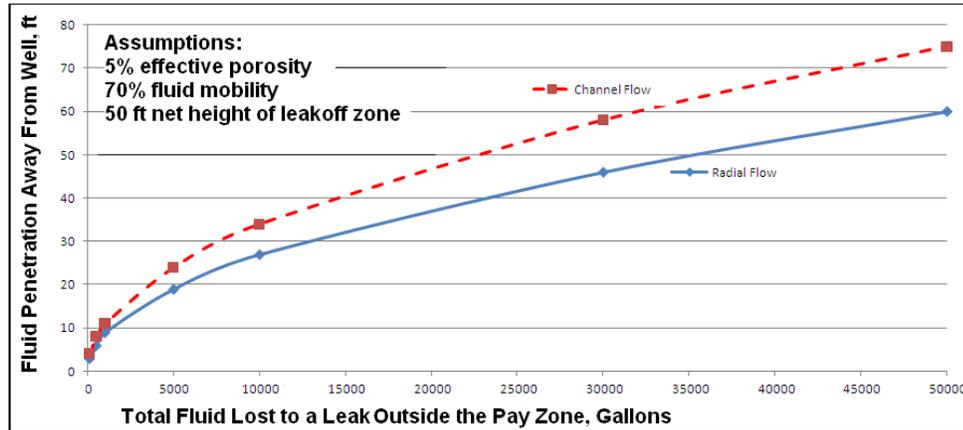
biodegradable) toxins if used. This is also a “highlighting” or risk reduction exercise to identify and replace materials with significant impact.

- Ability to recover the spill – liquid additives vs. dry additives; tanks vs. crash resistant totes; haz-mat response time and success. Local terrain is also a factor. Unless other data is available, no recovery is assumed for a loss of a liquid load following a truck wreck, although Haz-Mat operations are often successful in recovering fuel and chemicals stranded in tanks and impoundments. Eighty percent of any dry chemical oilfield fracturing chemical being transported is assumed recoverable (author’s experience).
- Volume of the spill – e.g., a ruptured side saddle fuel tank on a truck (150 gallons or 567 liters) vs. a spill of a whole load of a diesel refuel truck (3500 gallons or 13,250 liters). Haul capacities of typical transports were taken as volumes for spill potential.
- Well Construction – overpressure related incident – these are fairly constant across a region with the lower frequency being in areas where there is a high incidence of fracturing with common knowledge of adequate fracturing application for fracturing in the area. Prior to the frac job, well casing is tested to the pressure expected in fracturing plus a safety factor. Casing ruptures are very rare and are immediately seen by annulus pressure monitoring.
 - Cement isolation – cement top too low or cement job does not isolate the non-fractured thin gas productive zones. This is not directly connected with fracturing, but is a factor of inadequate cement coverage of gas zones (see the section on Well Construction). The cement is tested by the pre-frac pressure test. This is generally seen as methane migrating from a thin shale that is open to the annulus and pressures up a shallower zone. This type of event will produce methane increases in neighboring water wells but will not show frac chemicals. This type of behavior is not reported where there is adequate coverage of high quality cement and thus outside the scope of fracturing risk.
 - Channel leakage through long sections of the cement is rare. The possibility is usually eliminated by the required pressure test of the cement job and completion of repairs prior to a frac. In the event of a leak, the risk of frac fluid migrating more than a few feet in the small, usually discontinuous mud channels is very low and decreases even further with increasing depth. In deep wells (greater than 2000 ft.), with hundreds of feet of cement and dozens of natural rock barriers, this risk disappears.
 - Pipe design is insufficient for the job – potential exists for the fracture pressure to rupture the casing and cement sheath and communicate with fresh water sand. With two or more steel and casing barriers, this risk is significantly lower. Because this would be an improperly designed well, this is not considered in frac risk except in an overpressure situation.
 - Both the channel leak and the ruptured casing impact scenarios are considered as possible, but highly improbable. Leaks exactly at fresh water sand depths during the frac are a worst case scenario. The impact of such a leak through radial (outward flow) or even flow along a high permeability or fractured channel (estimated as a concentration of flow into 25% of the available porosity) would require thousands of gallons of fracture fluid to escape to create an invasion zone more than a few feet from the wellbore, Figure 31. Hydraulic fracturing durations are usually 20 minutes to 4 hours. Fluid movement through small channels in these short time periods will be on the order of 100 to 1000 gallons for a thousand foot channel of ¼” average diameter in four hours. Worst case penetration is 12 to 20 feet away from the well.

Even for extremely large volume loss from mechanical failures, the penetration distance is still very limited to the effects of rapidly increasing total porosity of the rock as the potential “impact”

zone is projected outward. Note from Figure 31 that even extreme volume losses of frac fluid, i.e., volume losses in the tens of thousands of gallons (which would be quickly noticed in the real world), would not penetrate even 100 ft in worst case channel flow.

Figure 32: Estimated penetration distances for radial flow and channel flow as a result of a leak during fracturing.



- Depth of intervals – Fracture height growth is limited by natural rock barriers and leakoff of frac fluid into permeable rock. As demonstrated by micro-seismic monitoring during fracturing, fractures rarely reach a vertical growth of a few hundred feet above the pay zone (reference Figures 18 & 19), particularly when frac rates are tailored to specific intervals. Shallower zones, nominally those less than 2000 ft would have the highest potential for hydraulic fracturing communication into a fresh water sand, although even for this potential event, there is no documented proof. The deeper the well, the less likely such an event would be. Deeper zones have more separation, more frac barriers and more permeable rock that would sap frac fluid away from the stimulation. For this analysis the transition depth of shallow (higher risk) to deeper well (lower risk) will be set at 2000 ft (610 m); selected based on separation of fresh water sands with a maximum depth of 1000 ft (305m) with a 1000 ft separation to the pay zone. Most commercial shale reservoirs are at 3500 ft (1067 m) to 11,000 ft (3354 m) deep, with an average depth of about 7000 ft (2134 m).
- Fracture Intersection
 - Fractures intersecting other fractures or other wells at the same depth in a pay zone are likely as the wellbore spacing (distance between wellbores at the depth of the pay zone) is diminished. Shale wellbores are intentionally set close together because fracture penetration is dominated by extensive natural fractures that limit overall frac growth. This type of fracture intersection was seen by the author on about 10% of wells (about 1 or 2 in 10 fracs in a typical affected well) in the Barnett during 2008. No incident of communication back to the near-surface fresh water sand was experienced or is known. Fracture intersection at depth and below the main cap rock or seal does not create a problem unless the intersected well is open to a fresh water zone.
 - Fractures intersecting an abandoned well are a rare, but known occurrence. If the well is properly abandoned, there is little or no risk of fresh water contact or contamination. If the well is an old, improperly abandoned well, the casing strength cement quality and the pipe strength must be considered low unless proved otherwise by testing. The low pressure of these old wells would very likely create an immediate pressure drop in any frac treatment that entered the old well, prompting investigation. Even when intersected, a properly abandoned well will withstand fluid movement towards surface. No documentation could be found for this type incident, but estimates from field personnel active in fracturing application over several decades indicates the figure is about 1 intersection or less in 10,000 fracs. The EPA has proposed a study on this subject.

- Other Factors – these are fracturing incidents that may or may not have an impact on fresh water pollution but many have a detrimental effect.
 - Earthquakes – Fracturing is a rock breaking action and will create seismic events that may create very small fault movements in rare cases (reference Figure 25). Direct connection of hydraulic fracturing to creation of measurable earthquakes is very rare with the main effect being mainly related to deep well injection of fluids, some of which may be produced fluids. Millions of seismic events of a magnitude of 3.0 (a “felt” tremor) and less are recorded every year, the vast majority are in areas where no drilling or fracturing is taking place (reference Table 9). Measurable earth tremors have been reported in areas of gas production including The Netherlands (high rate gas injection and withdrawals in a gas storage reservoir), Ft. Worth TX (Barnett shale gas production), Guy Arkansas (probable connection to deep well disposal), Colorado (military fluids disposal) and some historical reports in Eastern Europe (high rate gas production). Nearly all of these areas were in active fault areas (most previously unknown). No cases were found where moderate (magnitude 5.0) or large (magnitude 6.0) were directly confirmed to be caused by hydraulic fracturing or injection.
 - Seeps – natural seeps can be affected by oil or gas production, usually decreasing the outflow of the seep. In rare cases (only one known), fracturing of zones coincided with increase in seep outputs. The USGS has mentioned this possibility and terms it very rare (Fassett, 1997). One case in Canada is known in the past 14 years.
- Normal Fracture – no events, no leaks, no spills and no known intersections with wells that result in pollution. The “normal” occurrence is estimated at about 95% (probably a very conservative rate for “normal” operations).

Traffic related spills were estimated from rural interstate truck traffic, with truck wreck and truck rollover frequency estimates from NHTSA, FHWA and some state data. Twenty-five miles one way (spill rate disappears with an empty transport) and 1500 total trips/well (worst case). Contamination events are those known and documented by regulator or third party testing that was available on intranet search engines. Records of these events have been unevenly kept up to recent times and poorly kept in the 50's through the 80's, thus potential error is unavoidable. Pollution information that was politically motivated, obvious propaganda, from studies without scientific methods, lawsuit claims, and/or oil and gas industry-influenced data was not considered.

The frac specific estimates are **NOT** intended as accurate statements of individual service provider, operator or overall frac risk, there are simply too many unknowns and too wide a variable range. These data are modeled after general slick water frac practices. These risk estimates are better viewed as a comparison of the potential outcomes of the well development activities leading up to, during and after hydraulic fracturing.

The widely held prediction that spills from transport and well construction problems would be the biggest hazards has been borne out by documented cases of road accidents, spills during those accidents and others during fluid transfer. Road accidents and problems in transfer will have a different basis in different parts of the country as road design, weather and terrain changes. The flat areas of west Texas, for example, have a different accident frequency for trucks than mountainous areas with narrow roads, cold weather extremes and other factors not optimum for moving large equipment and/or high density tanker truck traffic. There is a realization in the industry that decreasing truck traffic is a key to reducing many problems faced by the industry and the public.

The level of spill damage varies from a minimal impact of a load of fresh water with no added chemicals to a severe impact of loss of a transport load of diesel fuel. The spill rates of diesel are generally low and compare to the spill rate of regular transport of gasoline and diesel to neighborhood service stations.

Spills of salt water, now increasingly used to replace fresh water in many fracturing jobs are more problematic than fresh water transport. The salinity of most reused produced water ranges from saline to brine (TDS of water suitable for fracs is about 50,000 ppm and less). Impact from such a salt water spill is compared to the amount of salt placed on icy roads in some states. (Salt usage is from state estimates and run 200 to 300 lb./salt per lane per mile per application) (source - Road Salt Use, EPA Road Salt document).

Potential pollution events:

1. Spill of a transport load (130 bbls or 5440 gallons) of water without chemicals.
 - a. High Side - Spill of a transport load of clean salt water of 35,000 ppm TDS (same salinity as sea water) – Total salt amount = 159 lb. of salt, (about the same as placed on ¼ to ½ mile of two lane in one application when treating icy roads (EPA salt reference). Wreck incident rate was 0.26 wrecks per million miles (Range of values was 0.18 to 0.26) with a rollover rate (spill) rate of 3.4% of wrecks. Assuming all the water was hauled by truck (unusual), 915 truck trips of 25 loaded miles. **Calculated frequency is 20 transport related spills in a million fracs (odds against 50,000 to 1)**
 - b. Low Side – Spill of a transport load of clean fresh water. It is generally identical to the raw feed water for municipal water supplies. Consequence is taken as very minor. Wreck incident rate was 0.26 wrecks per million miles with a rollover (spill) rate of 3.4% of wrecks. **Calculated frequency is 20 transport related spills in a million fracs (odds against 50,000 to 1)**
2. Spill of 500 gal concentrated liquid biocide or inhibitor.
 - a. High Side – transported in single wall, or non-crash proof container. 1 truck per frac, **Calculated frequency is 0.022 spills in a million fracs (odds against = 4.5 million to 1)**
 - b. Low Side – dual wall container (crash resistant), <25% loss. (frequency same as 2a)
3. Spill of 500 lb., dry additive, DOT approved totes, <10% loss.
 - a. High Side – toxic materials(**frequency same as 2a**)
 - b. Low Side – non-toxic (biodegradable, non-ED, non-bioaccumable) or food grade. (**frequency same as 2a**)
4. Spill of 300 gal diesel from ruptured saddle tank on truck in a road-way wreck
 - a. High Side – single wall fuel tank. 1500 trucks, 50 miles, 10% spill rate, **Calculated frequency is 195 transport related spills in a million fracs (odds against 5,100 to 1).**
 - b. Double wall tank, fuel tank relocation, or effective Haz-Mat fuel recovery. **Calculated frequency is 66 transport related spills in a million fracs (odds against 15,000 to 1).**
5. Spill of 3500 gallons (standard field location refueler) from road-way wreck.
 - a. High Side – older model refueler (non-compartment, single wall, no recovery. 5 trucks, 50 miles, 10% spill rate, **Calculated frequency is 1 transport related spills in about a million fracs (odds against 1 million to 1).**
 - b. Low Side – compartmentalized and effective Haz-Mat fuel recovery. **Calculated frequency is 0.5 transport related spill in about a million fracs (odds against 2 million to 1).**
6. Spill or leak of 500 bbl (21,000 gallons) of well-site water storage tank – no additives.
 - a. High Side - clean salt water of 35,000 ppm TDS (same salinity as sea water) – Total salt amount = 613 lb. of salt, (about the same as placed on 1 to 1-½ mile of two lane road in one application when treating icy roads⁹⁴. **Estimated frequency 1 in 1,000 fracs (odds against 1000 to 1)**

- b. Low Side – fresh water spill. **Estimated frequency 1 in 1,000 fracs (odds against 1000 to 1)**
7. Spill of water treated for bacteria control
- a. High Side – spill of 50 gallons frac water containing 0.0003 gallon. (1.1cc) biocide. **Estimated frequency 1 in 10,000 fracs (odds against 10,000 to 1)**
- b. Low Side – spill of 50 gallon. frac water treated with UV, ozone, or chlorine dioxide. **Estimated frequency 1 in 10,000 fracs (odds against 10,000 to 1)**
8. Spill of diesel while refueling pumpers.
- a. High Side -50 gal. of diesel from ruptured or leaking hose. **Estimated frequency 1 in 10,000 fracs (odds against 10,000 to 1)**
- b. Low Side – using routed fuel lines in pad ops. Volume reduced to drips. **Estimated frequency 1 in 100,000 fracs (odds against 100,000 to 1)**
9. Spill of 500 bbl (21,000 gallons) of stored frac water backflow containing routine levels of frac chemicals in recovered slick water frac fluid.
- a. High Side – non-“green” chemicals, high end of barium, heavy metals and salt range **Estimated frequency 1 in 1,000 fracs (odds against 1,000 to 1)**
- b. Low Side – “green” chemicals, low end of heavy metals, barium, & salt range. **Estimated frequency 1 in 1,000 fracs (odds against 1,000 to 1)**
10. Fracture pressure ruptures surface casing at exact depth of fresh water sand.
- a. High Side – no active monitoring of pressure or response to pressure changes. Contaminates aquifer with 50,000 gallons (190 m³) with 1.25 gallon (4.7 l) total of biocide lost with water. **Estimated frequency 1 in 100,000 fracs (odds against 100,000 to 1)**
- b. Low Side – with active monitoring & “green” chemicals – (1 minute to shut down and pressure fall off below leak rate entry pressure), loss of ~4200 gallons (15.8 m³) **Estimated frequency 1 in 100,000 fracs (odds against 100,000 to 1)**
11. Frac water cooling pulls tubing out of packer, placing frac fluid in sealed annulus with standard pressure monitoring.
- a. High Side – loss of 2 bbls (84) gal with non-“green” chemicals through surface wellhead valve. Total loss of 0.0005 gal (1.9cc) of biocide. **Estimated frequency 1 in 1,000 fracs (odds against 1,000 to 1)**
- b. Low Side – no loss of fluid (stays contained in the annulus) **Estimated frequency 1 in 1,000 fracs (odds against 1,000 to 1)**
12. Frac opens mud channel in cement on a well less than 2000 feet deep. Lost 6,000 gal (22.7m³), a leak rate through ¼” (6.3 mm) channel of 25 gal/minute (95 l/min.) for the entire 4 hour frac. Channel flow outwards focused in 50 ft (15m) of zone but lacks pressure to frac. Total penetration into formation equals 27 ft.
- a. High Side – Non-“green” chemicals and channel leak is not repaired, allowing gas to reach an upper formation. **Estimated frequency 1 in 1,000 fracs (odds against 1,000 to 1)**

- b. Low Side – “green” chemicals and channel leak is found and repaired after the frac.
Estimated frequency 1 in 1,000 fracs (odds against 1,000 to 1)
13. Frac opens mud channel in cement on a well greater than 2000 feet.
- a. High Side – Low cement top (500 ft of cement) – and exposure to annular areas directly below water sands. Probable frac fluid loss of 6,000 gallons would fill the annulus but not leak off significant fluid into shallow formations (lack of focused pressure). If the leak is not found and repaired, higher pressure methane gas from the pay zone may create high pressures in upper zones. **Estimated frequency 1 in 1,000 fracs (odds against 1,000 to 1)**
- b. Low Side – High cement top (all gas productive sands covered and no gas migration). No leakage possible. **No impact – frequency unimportant**
14. Frac intersects another frac or wellbore in a producing well within 1000 ft of the treated well and in the pay zone. This is actually very common in closely spaced wellbores with shale wells on close spacing. The impact of fracturing into another well in the same horizon is virtually zero so long as the well has the proper wellbore integrity.
- a. High Side – The well intersected with the frac has poor mechanical stability (poor cement, corroded pipe, leaking packer, etc.) and leaks a similar amount to a ruptured casing example. **Estimated frequency 1 in 10,000 fracs (odds against 100 to 1)**
- b. Low Side - no fluids lost outside of pay zone on either well. Wells in the fracture growth plane are mechanically sound. **No impact – frequency unimportant**
15. Frac intersects an abandoned wellbore
- a. High Side – well is improperly abandoned and fluid is able to travel up the abandoned wellbore, losing 50,000 gallons (190 m³) with non “green” chemicals at the surface of the abandoned well. (Only two cases known). Biocide lost equals 12.5 gallons (47 l). If lost to the formation, channel flow would extend 75 ft (22.8 m). **Calculated frequency 2 in a million wells, Odds against in a frac 500,000 to 1.**
- b. Low Side – Pre-drill search is conducted to locate near-by abandoned wells and mines. Checks for surface seepage also a risk decreasing step. No problems if well is properly abandoned – no fluid lost. **No impact – frequency unimportant**
16. Frac to surface through the rock strata – shallow well (less than 2000 ft or 610 m).
- a. High Side –50,000 gallons (190 m³) non “green” fluid travels along a surface penetrating fault and only one case was found (during pressure testing in the drilling phase in very shallow competent pay zone at a few hundred feet depth). Other possibilities are in areas with poor rock seal. Used a worst case projection of 10 cases worldwide (assume 2 million fracs) for shallowest wells (no cases with deeper well fracturing are known). **Worst case estimate of 5 in a million fracs, (odds against in a frac 200,000 to 1).**
- b. Low side – same fault scenario with one known case, 50,000 gallons (190 m³), 75 ft spread of “green” chemicals through channel flow. **Worst case estimate of 5 in a million wells, (odds against in a frac 200,000 to 1).**
17. Frac to surface through the rock strata – deep well (greater than 2000 ft or 610 m)
- a. There are no documented or even rumored cases of this type of occurrence. **No frequency – impact unimportant**

18. "Felt" earthquake resulting from hydraulic fracturing of magnitude = or greater than 5) (excludes deep well disposal)
 - a. High Side – fracturing into a fault with sufficient length mile (probably clearly visible on 3D seismic) might produce a tremor, depending on formation stresses, depth pressure, rate and volume pumped. Severity increases with length of fault and ability to release stresses by pumping. No directly attributable cases reported. **No Frequency**
 - b. Low Side - if investigation of geologic hazards such as faults by 3D seismic, areas of possible fault activation can be substantially avoided. Occurrence could be effectively eliminated. Impact of small fault activation is near zero. **No Frequency**
19. Frac changes output of a natural seep at surface. Normal outcome in shallow wells is to decrease the output of the seep.
 - a. High Side – Drilling shallow wells, or completing wells with insufficient cement and/or very large fracs in areas near natural seeps of oil or gas could increase seep output, normally for a short time. Impact is expected to be minor. **Estimated frequency of 1 in 100,000 wells (with ten stages each) (Odds against in a single frac 1 million to 1)**
 - b. Low Side – wells actually drain the seep pathways and decrease the seep flow. **No impact, frequency unimportant**
20. Emissions (methane, CO₂, NO_x, SO_x, etc.)
 - a. High Side – conventional operations on scattered single wells (no pads), using gasoline or diesel powered equipment. **High frequency, moderate impact.**
 - b. Low Side – substituting methane for up to 50% of the diesel power, using pad operations to concentrate wells, grouping operations to reduce road miles, use of pipelines instead of trucks, electric engines wherever possible, using low pressure gas recovery at all operational steps, and minimizing fugitive emissions. **High frequency, low impact**
21. Normal Frac Operations without significant (reportable) spill, rupture, leaks, etc., of negative fracturing events. **From consideration of preceding data, the no-incident rate is assumed to occur from 99 to 99.9% of the time.**

Figure 33 is an estimate of base case fracturing risk with little use of technology. The estimates will have a range of consequence and occurrence depending on a variety of factors including local geology, expertise and experience of service infrastructure, operating company knowledge and ethics, and state regulations (including inspection and enforcement).

the blender immediately before being injected down hole. Water storage in double lined and monitored pits and portable single wall, steel tanks of 500 bbl (21,000 gallon) capacity.

- Frac Assumptions: Average frac duration 1 to 4 hrs., Average pump rate 80 bpm (3360 gal per minute), Average of 10 frac stages per horizontal well.

Table 16: Chemicals in a risk example of a four million gallon slick water frac (CAS numbers in Table 4).

Frac Material	Composition	Amount – Total Volume or Weight used in the well (all fracs)
Fresh or Salt Water as Frac Base Fluid	H2O	5,000,000 gal (8 large swim pools)
Sand (dry without any coating or treating)	Sand (silica dioxide)	3,000,000 lb. (would fill a 50 ft by 60 ft by 10 ft small barn)
Acid for perforation breakdown (2000 gal per stage)	HCl – 15% concentration (28% HCl used to treat water in swim pools). 20% HCl used to wash new brick on houses. Stomach acid is about 1% HCl. Not used on all jobs.	20,000 gal (about what a small city would use in a year in its private and public swim pools) – spends completely in the formation – no live acid returned.
Friction Reducer or FR	Polyacrylamide (used in baby diapers)	2,000 lb. (enough for 180,000 diapers)
Bacteria control	UV light (no chemicals), chlorine dioxide (no residual), chlorine, Quaternary Ammonium salts, and Tetrakis hydroxymethylphosphonium (THPS). - effective procedure used with preference to lowest toxicity	0 (for UV light) to 1500 lbs. for quaternary or glute compounds. (Working towards complete spending or biodegradation materials with aim to do it mechanically.)
Corrosion Inhibitor – for acid	Various – Quaternary Organic Amine base to Imidazoline	50 gallons total – not used if acid is not used

Analyzing the available frac data has produced only anecdotal information of stories of fracturing into an unknown and improperly abandoned well and having frac fluid communicate back to surface (two cases are “rumored” but no details or well names could be found). An EPA Study proposal for fracturing into abandoned wells (dated 2010) was proposed, but no further information was found.

Spill estimates from storage (primarily overflows) are made using double lined & monitored pits. Portable steel storage tanks offer less leak/overflow possibility, but more overhead and added corrosion potential. Many of the ponds, if only fresh water was stored, can be quickly turned over to the land owner for private use after drilling and completion operations are complete.

For water disposal, all 350 hauls are used with 50 miles round trip to disposal or treating site. Basing the spill rate on accident frequency in the entire 50 mile round trip is an effective doubling of the actual safety factor, since the liquid transport rollover rate is highly reduced when the truck is empty and the empty truck poses almost no spill potential outside of its own fuel. Many pad locations may have an onsite disposal well that negates this entire figure. Spill potential from a treating site is not directly estimated but is included in the transport estimation for spill loss.

Frac chemicals generally are spent (acid and biocide) on target mechanisms or adsorbed in the formation (corrosion inhibitors). Less than one-third of any polymer used may return and a trace of other chemical residual in a few cases (King, 1988; Woodroof, 2003; Asadi, 2002).

Other spill, leak and failure possibilities may exist, but the extremely low potential frequency of occurrence and/or the very low consequence tend to eliminate them from consideration. The frequency of occurrence and the impact of other events have been boosted to worse case to offset possible errors.

Conclusions

Drawing conclusions from this study involved an initial separation of well construction issues (where a company's design philosophy in a local geologic area can be a major risk differentiator) from the specific rock fracturing risk (where every company faces near-identical risks). Well construction, being a separate risk entity, is not considered here.

1. The primary conclusion that fracture treatments do not penetrate fresh water supplies in a properly constructed wellbore is derived from a preponderance of evidence from: monitoring fracture growth (microseismic, tracers, logging, tilt meters, pressure tests); absence of primary frac chemical components outside the pay zone; limitations placed on fracture growth by natural seals, frac tracers, frac barriers, leakoff and a 60 year history documenting frac containment in numerous geologic settings. **HOWEVER:** this conclusion is on a narrow topic of fracture pumping, and is not an innocent verdict on the entire well development process.
2. The potential for even a small amount of chemical contamination of underground or surface sources of fresh water from the specific act of fracturing, applied in adequately constructed wells with pay zone depth of greater than 2000 feet, is arguably less than one in a million fracs due to the self-limiting nature of fracturing leakoff and the numerous frac barriers found in every deeper formation sequence.
3. Height of fracture growth in deep wells is usually a few hundred feet above the targeted hydrocarbon zone but thousands of feet below the deepest fresh water sands. Documented by downhole microseismic, tilt meters, tracers, logging and other methods (Fisher, 2010).
4. The potential for chemical contamination of underground or surface sources of fresh water during all phases of well development comes exclusively from: road transport of fracturing components or fuel, on-sight storage and surface mixing of fluid components, and failures in well architecture caused by inadequate well construction methods, usually centered on inadequate cementing operations.
5. From construction of a dual risk analysis, featuring non-technical vs. technical application of fracturing, there is sufficient confidence that frequency of spills or leaks from higher risk events (transport, storage and well construction) can be sharply reduced by more attention to the root cause of these spill or leak events.
6. With proper well construction, there was no documented case located of fracturing chemical migration to a fresh water aquifer or to the surface from a zone deeper than 2000 ft. Cases of suspected contamination by chemicals in shallower zones are known, with many, if not all, linked to poor isolation of the well during the well construction phase.
7. Although the impact of spill and leak events are generally low, they can be decreased further by reducing number, amount (concentration and/or activity), toxicity and environmental permanence of chemicals used in fracturing. Chemical rating systems that focus on these issues should be a part of the planning for any frac treatment.
8. For targeted hydrocarbon pays of less than 2000 ft depth, state regulators with knowledge of local geological systems may need to set specific limits on well depth, frac volume, rate, or type of fluid. The special case of fracturing in very shallow wells, particularly those at depths less than about 2000 ft or with fresh water within 1000 ft of the hydrocarbon containing formation, is cause for concern and additional evaluations of geology, frac rates and volumes are required.
9. Methane presence is commonly recorded in water wells across the country and may predate any drilling or fracturing in the area. These methane occurrences may be biogenic or thermogenic methane and can be widely linked to natural seeps of methane gas, both continuous and episodic. Methane may increase during a water well's life as water is produced, as a result of liberating methane that was adsorbed in and onto organic materials in the sediments. This type of methane increase is particularly active in fresh

water containing coal seams and high clay content shales. As the fresh water aquifer levels are drawn down, the methane adsorbed on the organics will desorb and overall methane content in the water well will increase. Avoiding coal seams and high organic source rocks by proper cement isolation in the fresh water wells is required to minimize this problem.

10. Potential for increasing methane in nearby water wells from oil and gas well development activities can be increased by poor cement isolation and inadequate cement level in surface or production strings.
11. Transparency is, by necessity, a two-way street and needs to be addressed by all parties in the discussion. The oil and gas industry needs to explain its processes, identify chemicals to the public and improve the well development process where needed. The oil and gas industry must work to replace the few toxic chemicals we use (primarily biocides and a few surfactants) with chemicals that are low impact and biodegradable; perhaps a similar approach to that used successfully in the North Sea. The public needs to understand what the industry is doing and be able to engage on a local and national forum with a solid base of understanding. Media should disclose its bias and lobbying support.
12. High quality research papers using accepted scientific methods and without overt or covert political objectives and/or corporate influence do not appear to have received equal attention or air time in a media driven by sound bites. This must change if decisions are to be made on facts.

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