Review of Stimulation Fluid Retention Mechanisms and Likelihood of Fluid Communication with Shallow Aquifers

–What's New and Different Since the 2004 EPA Study?

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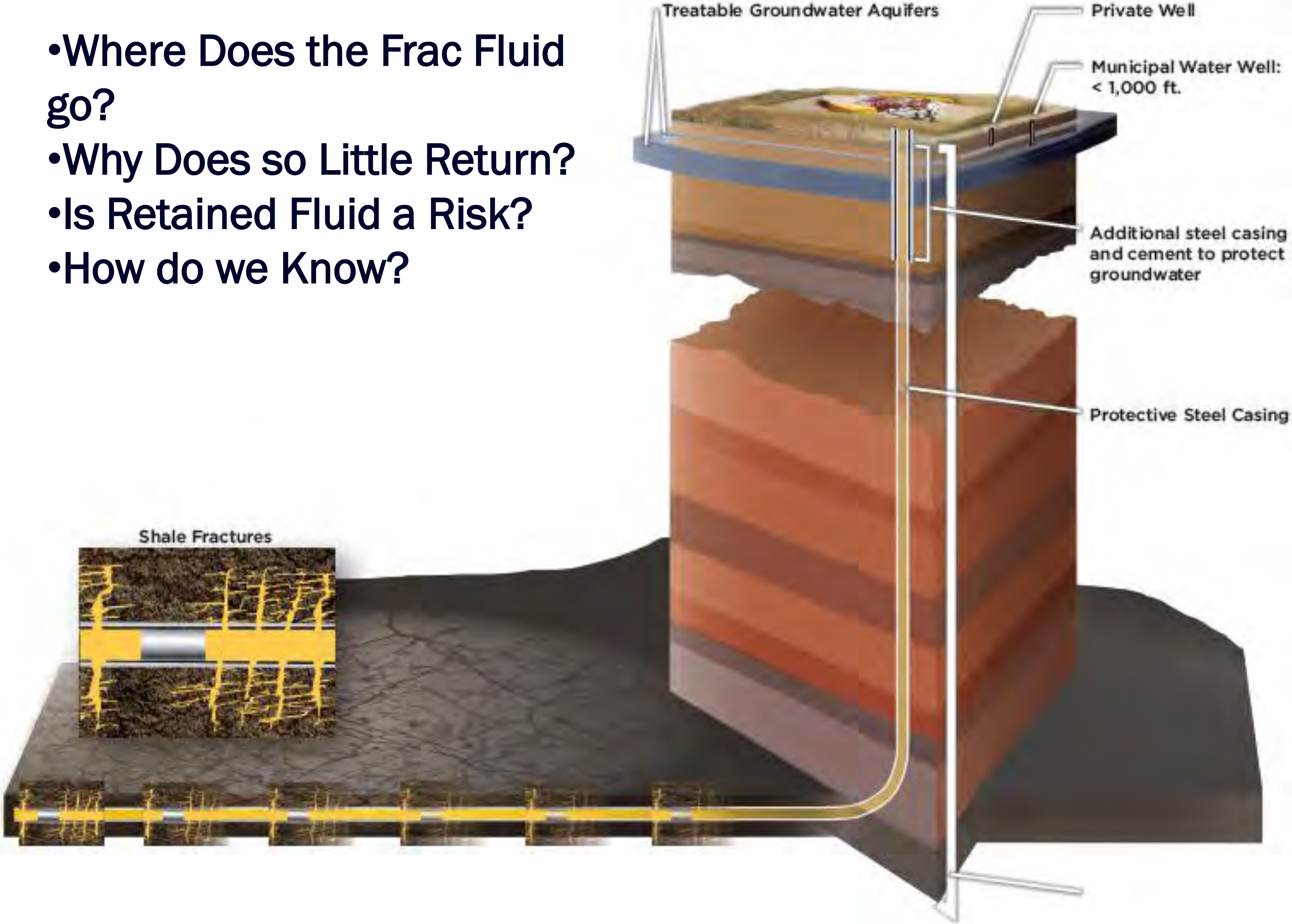
*I do not represent my primary employer in this matter; information and opinions do not represent the views of my employer and are presented on my own time with prior approval.

Why is it Relevant to Revisit the 2004 EPA Fluid Transport and Retention Discussion?

- There are differences between shale gas and shallow coal bed development that should be distinguished and addressed.
- Continuing Public Mistrust on the subject: *Public thinks of this fluid as “pools” of subsurface toxic waste that will eventually “float” to the surface.*
- Public looks to EPA for assurance on this topic.
- New Information and monitoring techniques have shed some light on mechanisms and fracture propagation.

- Where Does the Frac Fluid go?
- Why Does so Little Return?
- Is Retained Fluid a Risk?
- How do we Know?



Natural Fracture Generation

- Because pore space did not expand during burial of the Marcellus Shale, the generation of natural gas in this organic-rich unit resulted in an additional increment of pore pressure to such a magnitude that the rock cracked in a massive network of fractures![1]
- Resulted over-pressured characteristics indicative of a closed system.

[1] Engelder, Terry: "Unconventional Natural Gas Reservoir Could Boost U.S. Supply," Penn State Live (January 17, 2008).

Joints
Systematic
and
Widespread

Picture from November 2009 ***OilandGasInvestor.com*** *Peter M. Duncan founding president of MicroSeismic Inc. Horizontal well image courtesy of Bill Kappel USGS, Ithaca, NY*

Faults
Unsystematic and
Isolated

Shale Gas Production Mechanism

- Shale - both gas source and "sealed" reservoir
- Mechanisms by which gas is produced from a shale reservoir :
  - depletion of the free gas stored in the fracture network (natural and induced)
  - depletion of the free gas stored in the matrix porosity, and
  - Desorption
  - A dual porosity – triple mechanism system

Microfractures in organic rich shale. Hunt, 1995.

Why We Fracture Shale Gas Wells- Horizontal Wells are not Enough

- **Even Over-pressured Sealed Naturally Fractured Shale System Alone Will Not Produce Economic Quantities of Gas**
- **Goal is to give every gas molecule a high-speed path to the well-bore**
- **<u>The hydraulic fracturing process creates *not only tensile fractures*, but also *shears* existing fractures</u>**

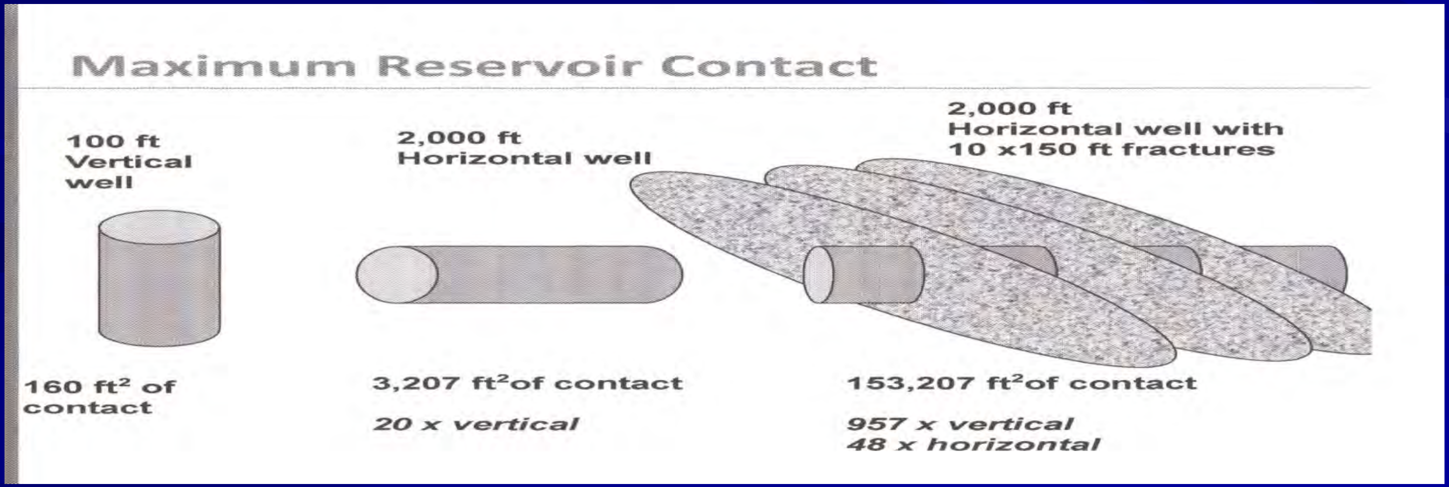


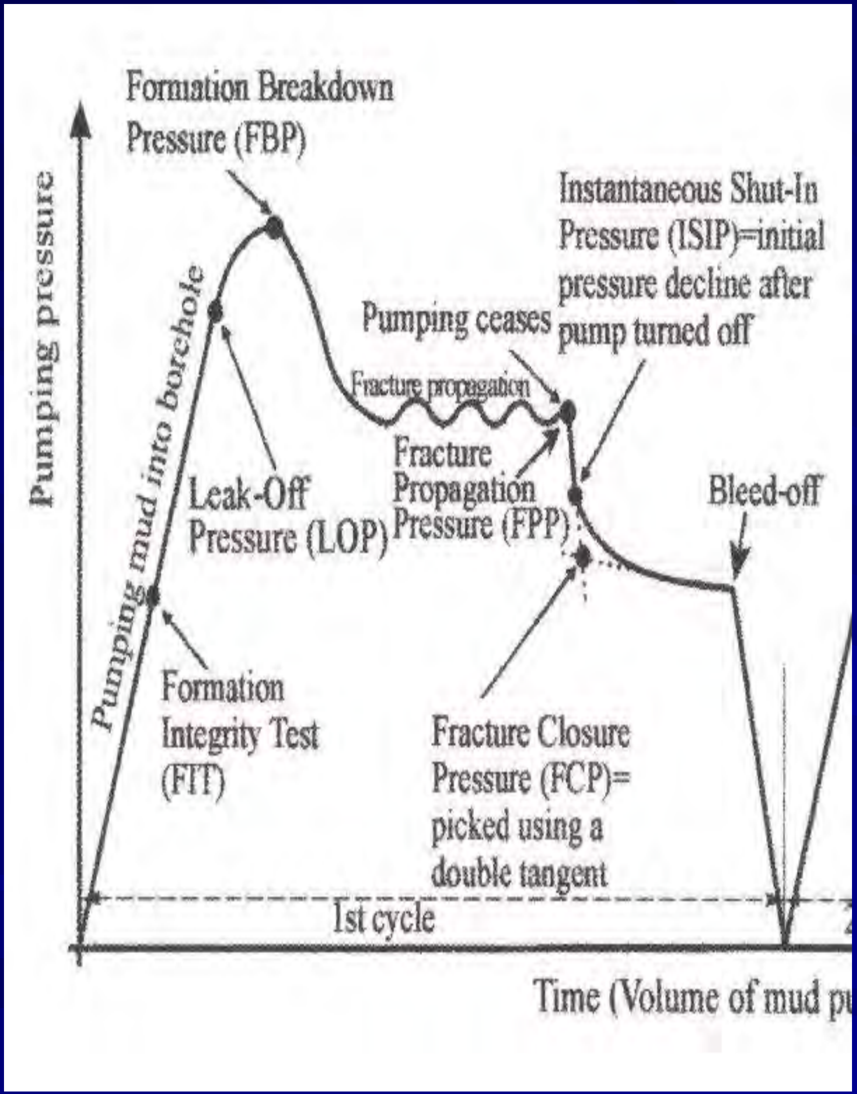
Diagram from: Packer's Plus: Good Fracturing Practices in Horizontal Wells Multi Stage Fracturing System Solutions

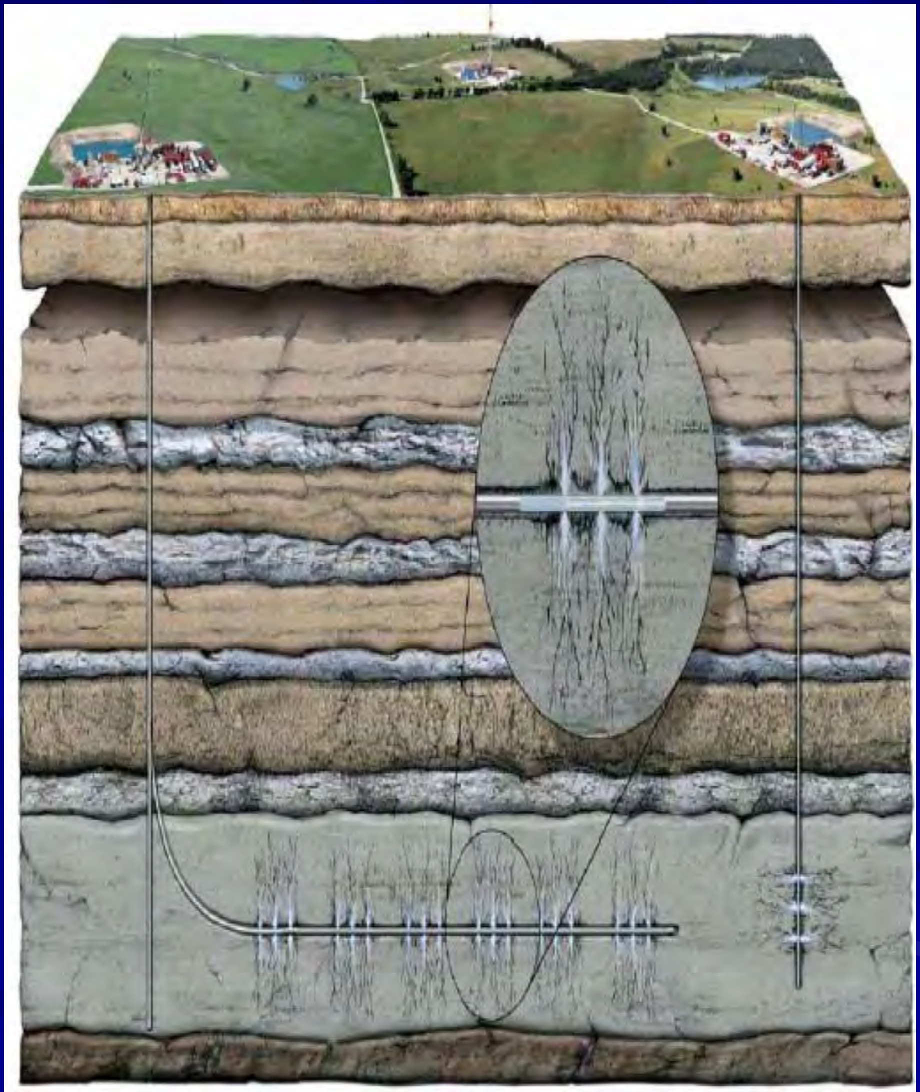
How Much Fluid Retained?

- **Inject Average 4+ million gallons of fresh water plus 4500 gallons of chemicals and 1400 gallons HCL** (Range Resources and others)
  - Approximately 1000 gallons of combined scale reducer, friction reducer and biocide per *million gallons* of water
  - Plus another 300 gallons of HCL per million that is expected to immediately react and decompose into inorganic salts and CO_2
- **Produced Fluid?:**
  - Less than a million gallons of water is produced to the surface over the life of the well
  - Rates decline and become more saline over time

Why Does so Little Water Return to the Surface and Does it Matter?

Mini-frac (cased hole) or leak-off test (open hole) pressure test versus time, showing definitions of pressure terminology

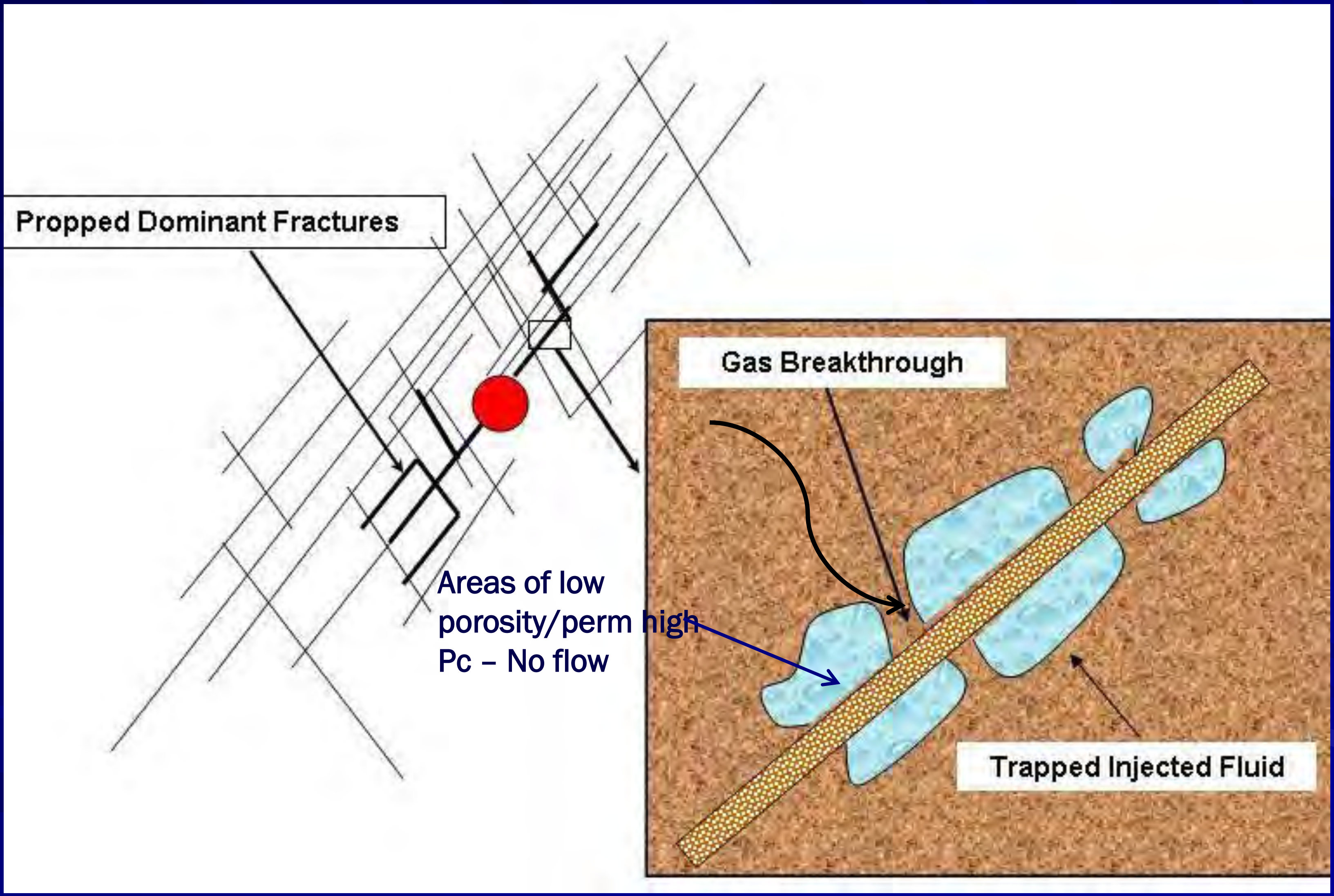




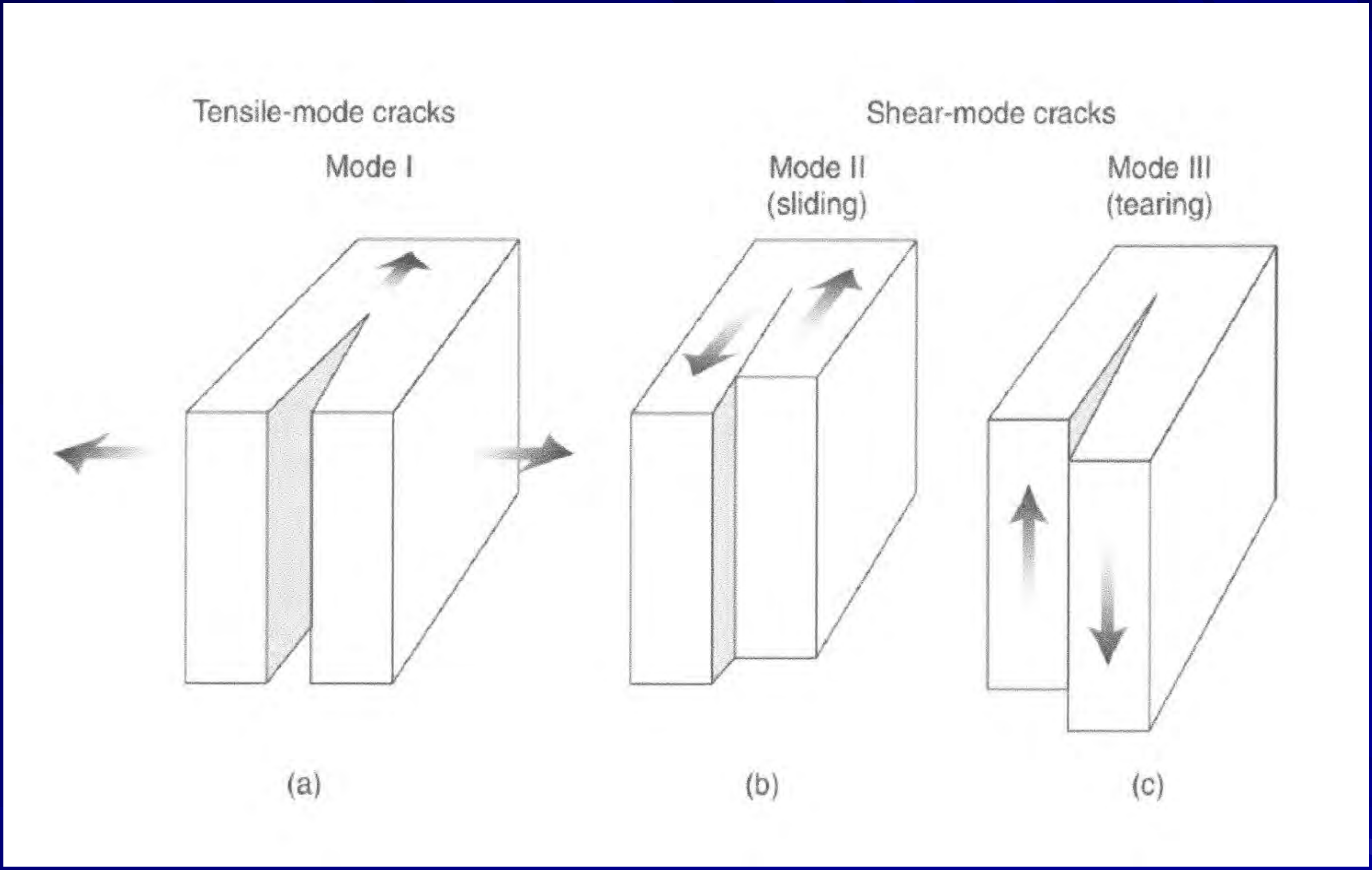
http://spec2000.net/10-closurestress.htm

Mechanisms for Fluid Retention

- Fluid **"leak-off"** into the fracture face. In formations with low permeability and low water saturation this fluid is permanently phase trapped by capillary forces.
- Hydrophilic clay **adsorption** and **swelling** in pore throat.
- Narrow fracture branches (shear fractures as opposed to tensile fractures) trap fluid by capillary forces and **stranding**.
- Fluid in **proppant packs** may be unable to move as fluid prefers going around the packs.
- Fluid may move by **gravity** to the bottom of the fractures and unable to move as reservoir flow dynamics slow with depletion. (Daneshy, 2010)



Adapted and Modified from Penny, Pursley, Holcomb, SPE paper 94274 April, 2005



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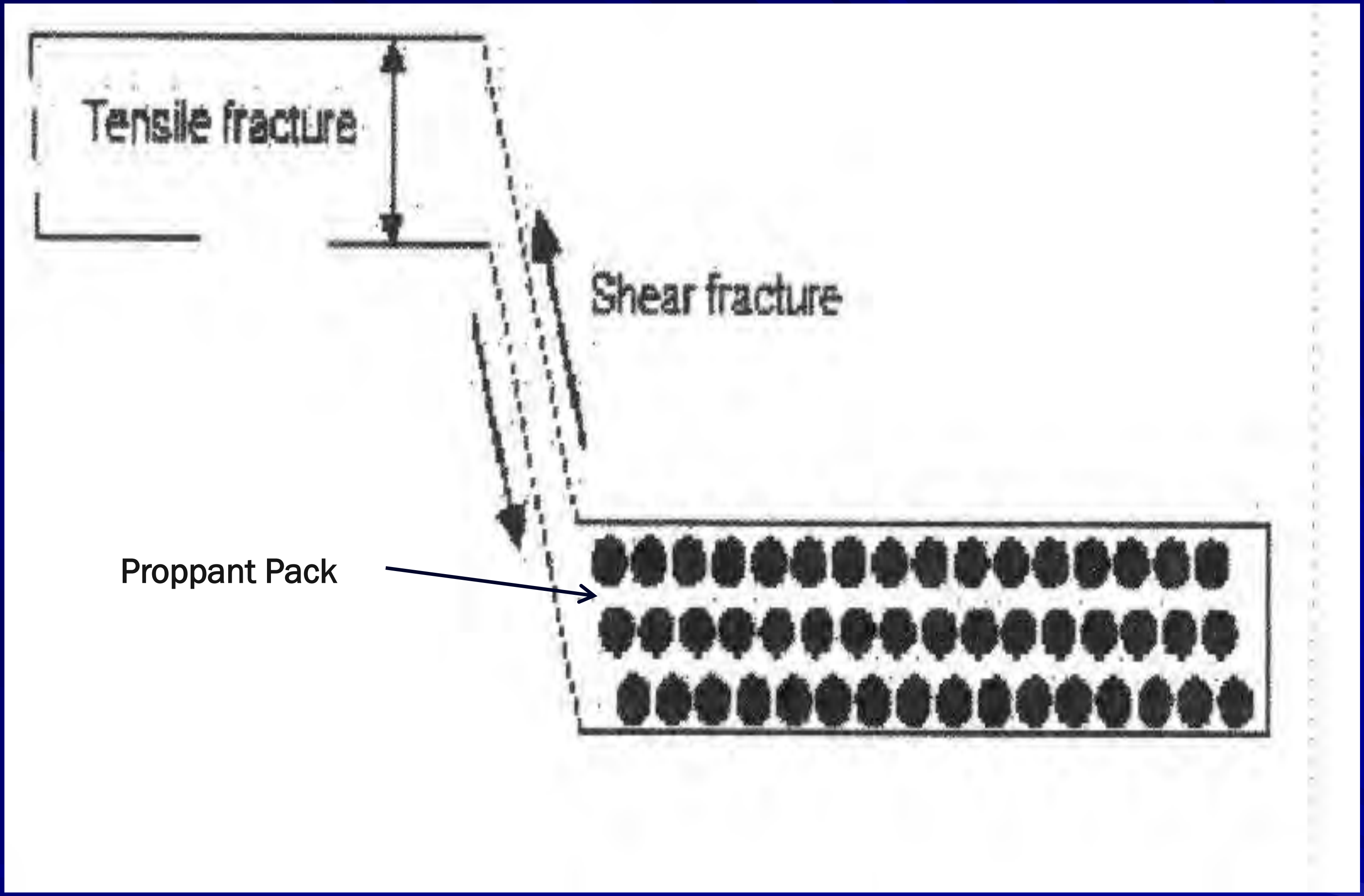


Modified from Daneshy, 2010 E&P Magazine

Other Considerations

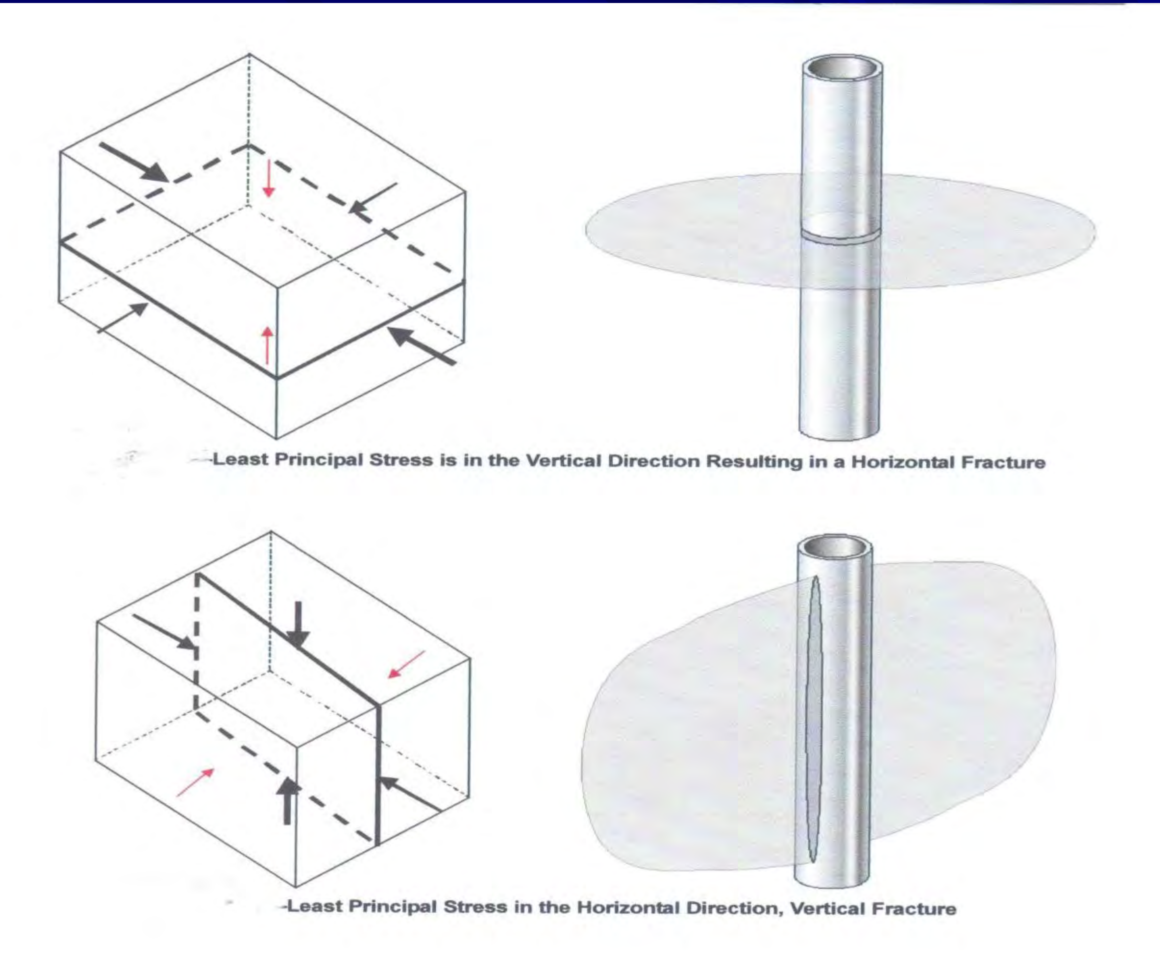
- Vertical Separation:
  - The developable formations separated from potential aquifers by at least 3,000 feet (and probably more) of sandstones and shales (of low permeability).
- Pressure Applied Limited Time
  - Fracturing pressures applied for short duration , while the required travel time for fluid to flow from the shale to the aquifer under those pressures is measured in years
- Pore Volume
  - The volume of fluid used could only fill a small percentage of the void space between the shale and the aquifer and the already diluted chemicals would be further diluted by the formation water. (100 million gal/acre with 3000 ft of separation from aquifer - 16 billion gal/160 acres)

Other Considerations cont.

- Adsorption
  - Some of the additives would be adsorbed by and bound to the organic-rich shales.
- Flow Direction – Pressure Sink
  - Any flow of frac fluid toward an aquifer through open fractures or an unplugged wellbore (remote) would be reversed during flowback, with any residual fluid further flushed by flow toward the production zone and well bore as pressures decline in the reservoir during production. (Pressure Sink)
- Anomalous Stimulation Pressures
  - The fracturing contractor would notice an anomaly if conditions led to the inability to maintain the predicted fracturing pressure.
- History
  - The historical experience of hydraulic fracturing in tens of thousands of wells is consistent with the analytical conclusion.

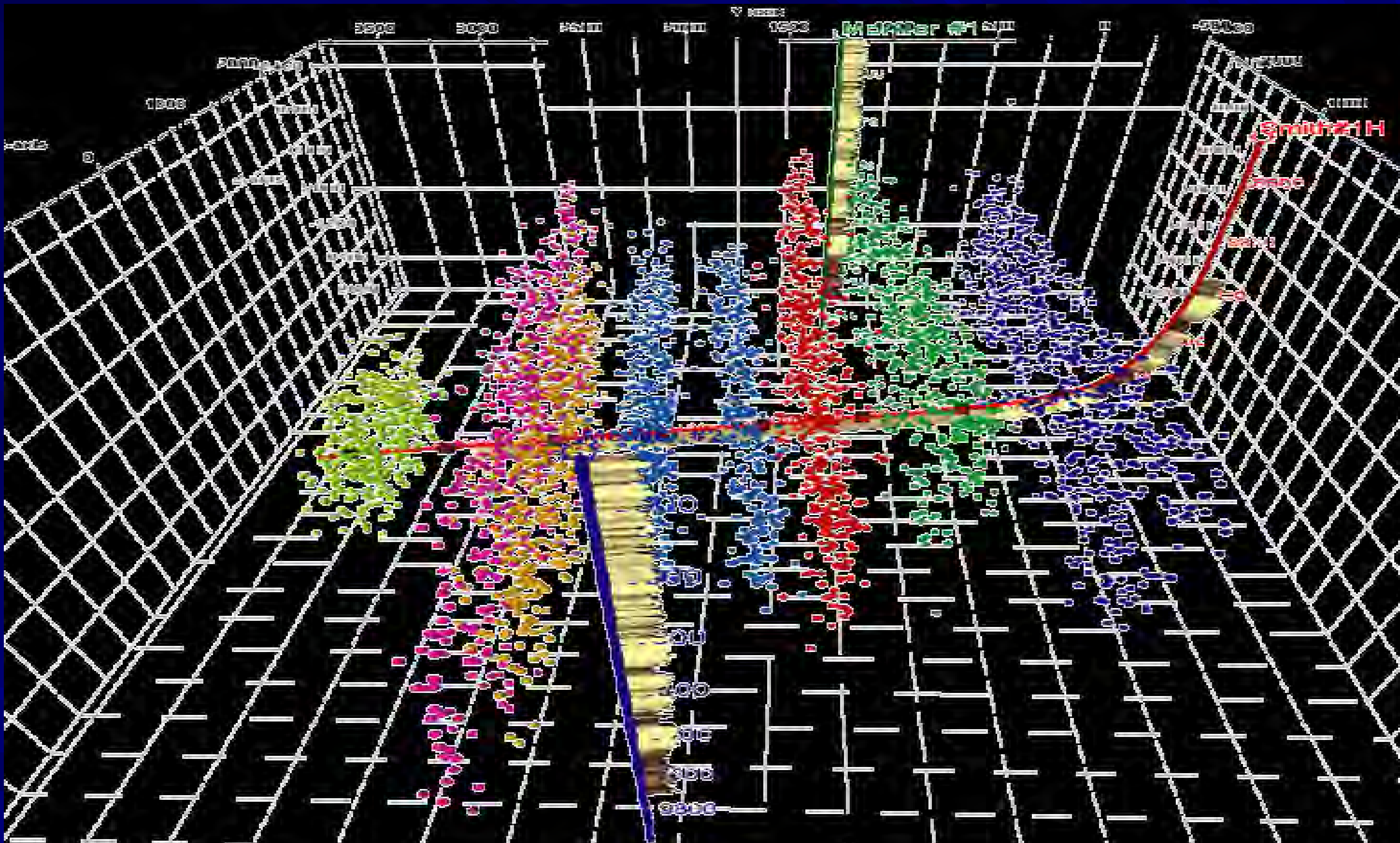
Likely Development Depths for Large Volume Stimulations?

1. Least Principle Stress Vertical at < 2000 ft. so Fractures Propagate Horizontal *API*
2. We Need Depth for the Desired Over-pressured Conditions

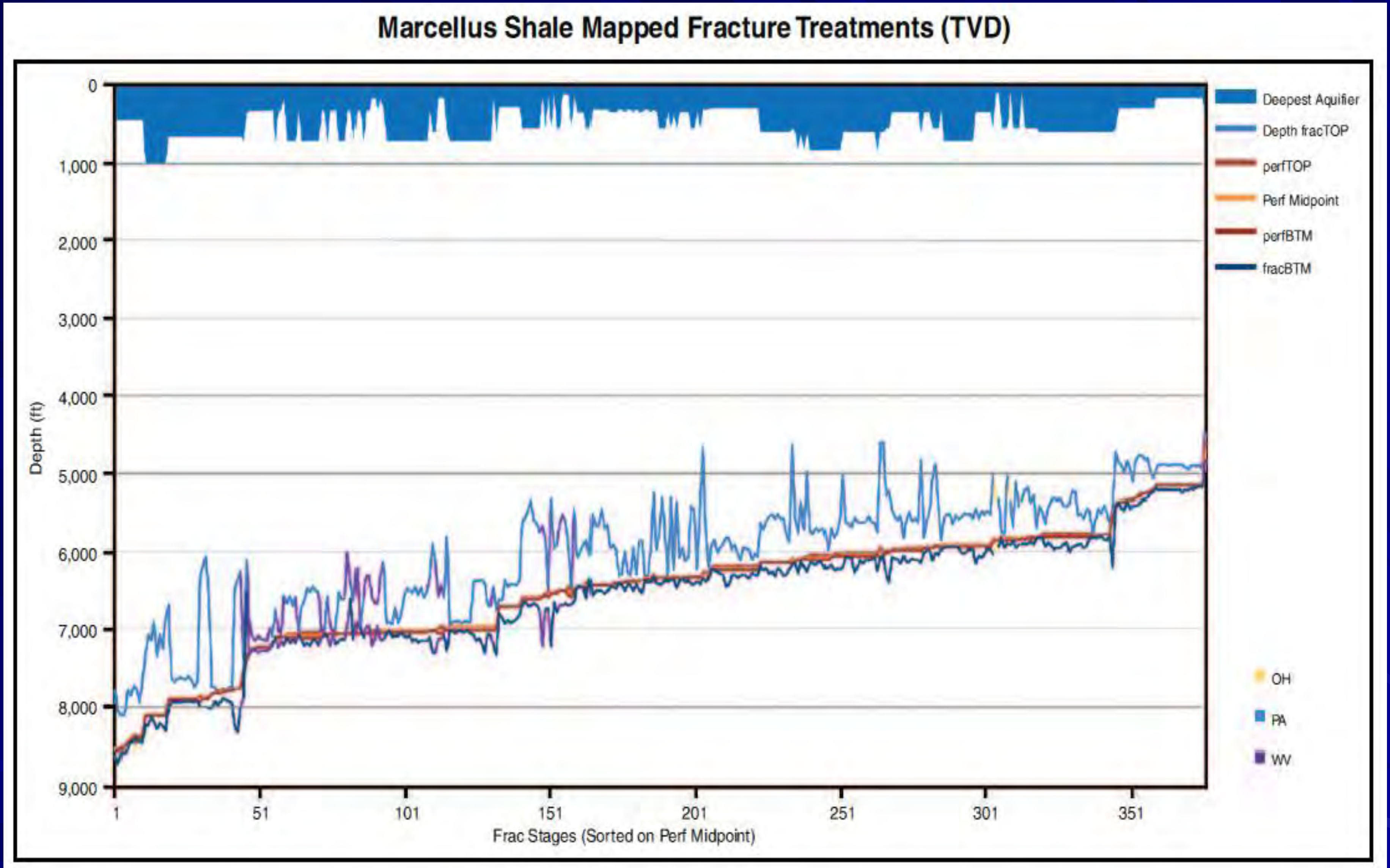


Picture Source API Hydraulic Fracturing Operations Well Construction and Integrity Guidelines
API GUIDANCE DOCUMENT HF1 FIRST EDITION, OCTOBER 2009
In NY, any proposed drilling less than 2000 feet deep or 1000 feet below USDW requires site specific SEQRA (7.1.5 dSGEIS)

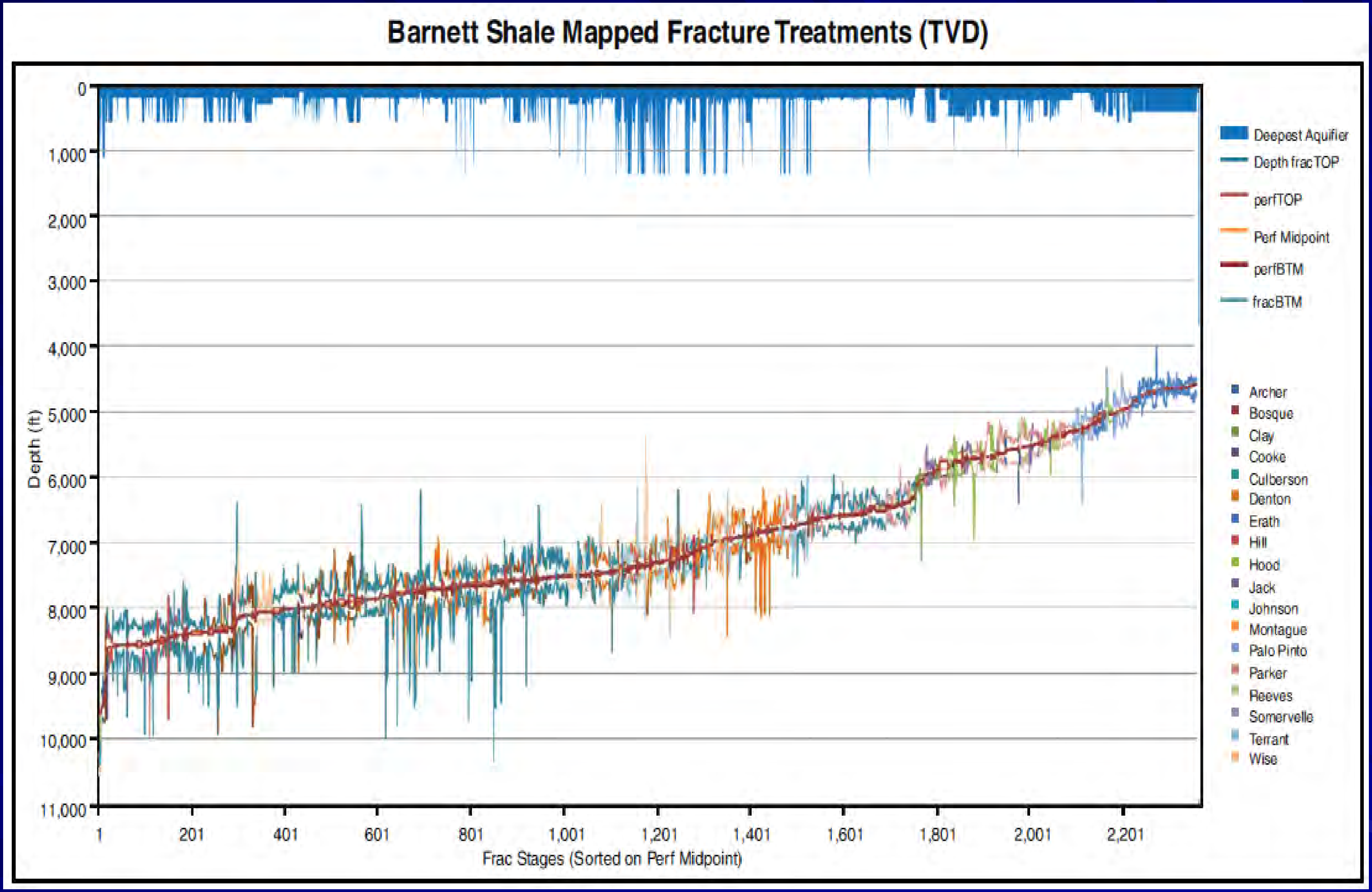
How Do We Know Fractures Height is Limited?



Packer's Plus: Good Fracturing Practices in Horizontal Wells Multi Stage Fracturing System Solution
http://www.packersplus.com/pdfs/Good%20Fracturing%20Practices%20SPE%20Dallas%20July%202010.pdf



American Oil and Gas Reporter, July 2010 Kevin Fisher, Pinnacle Resources



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Recommendations

- Examine the New Literature on Fracture Propagation and Water Retention Mechanisms Since 2004 EPA Study.
- Distinguish between the various types, sizes and depths of fracture stimulation.
- Seek help from industry on simulation and extensive micro-seismic data already collected.
- Convey conclusions decisively to public .

Review of Stimulation Fluid Retention Mechanisms and Likelihood of Fluid Communication with Shallow Potential Aquifers in Shale Gas Development

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The statements made during the workshop do not represent the views or opinions of EPA. The claims made by participants have not been verified or endorsed by EPA.

What happens to injected fluid in the subsurface and whether or not it is a risk to potential sources of drinking water has previously been reviewed by others including EPA in the 2004 study of possible effects on USDW from hydraulic fracturing of shallow coal bed reservoirs (EPA, 2004). However, as opposed to coal bed methane development where stimulation volumes were relatively small, fluid recoveries high, and depths shallow; the development of shales and other "tight" formations involve large fluid volume stimulations in long horizontal wells with typically very low fluid recoveries but at generally deeper target depths. It is therefore prudent to revisit distinguishing and relevant aspects of the fluid retention subject.

Relevant factors to consider include explaining low overall fluid recoveries occurring with most horizontal well stimulations in low permeability, assessing if there are any potential induced or natural paths with conductivity from the target formation to the shallow aquifers and if so is there a persistent driving force toward the shallow aquifers. While this abstract addresses primarily Devonian and Ordovician shales, the concepts are applicable to many other low permeability naturally fractured formations.

With continued increase in temperature and pressure during rapid burial and dewatering, organic matter within shale was converted into natural gas. Because permeability was low and burial rapid, pore space could not expand sufficiently to accommodate the gas generated. The gas generation thus resulted in an incremental pore pressure to such a magnitude that the rock cracked in a massive network of natural fractures. (Engelder, 2008) As more hydrocarbons were generated, the cracks continued to grow until they opened into full scale joints or natural hydraulic fractures which culminated in significant over-pressuring as the gas was unable to escape the relatively closed system. Although other overlying organic rich shales have similar fracture mechanisms, such complex joint systems do not likely extend conductively very far vertically. Certainly other tectonic related faulting occurs in the subsurface but it is rarely systematic (Engelder, 2009).

When these natural fractures are then subsequently hydraulically fracture stimulated in horizontal wells, the wells typically exhibit good gas production but poor or slow fluid recovery. The fluid recovery factor is usually significantly less than 50% and in horizontal wells in low permeability formations such as Marcellus, the recovery of total produced water, which includes both injected and natural formation water, is often less than 20% of total injected fluid volume. The relative contributions to fluid entrapment are still not completely understood or quantifiable but include:

1. Fluid “leak-off” into the fracture face. In formations with low permeability and low water saturation this fluid is permanently phase trapped by capillary forces related to pore size, size distribution, and wettability.
2. Hydrophilic clay adsorption and clay swelling restricting flow.
3. Narrow fracture branches (shear fractures as opposed to tensile fractures) trap fluid by capillary forces and stranding especially beyond the zone of production influence.
4. Fluid in proppant packs may be unable to move as fluid prefers going around the packs.
5. Fluid may move by gravity to the bottom of the fractures and unable to move as reservoir flow dynamics slow with depletion. (Daneshy, 2010)

Permanent fluid retention by the formation is possible via the fluid leak-off mechanism since some fracture fluid is injected and imbibed into the reservoir rock surrounding the fracture (Penny et al, 2005) . These low permeability facies have extremely small effective pore throat radii and/or micro-fracture widths, high irreducible wetting phase saturations and significant capillary pressures that generally increase as permeability decreases (Kalfayan, 2008). As the well is produced, the produced gas must overcome the capillary pressure at the formation-fracture interface. When the gas does succeed in breaking through the fluid at the interface, the gas flows through the point of least resistance leaving a large portion of injected water phase trapped in the reservoir rock and at the reservoir-fracture interface. While low permeability limits the leak-off penetration, the larger surface area of the off-balance fractures compensates for this effect and can allow a substantial volume of fluid to become trapped in the formation. Some authors believe that this leak-off effect in low permeability formations is limited and accounts for less than 25% lost fluid but indeterminate because of the uncertainly of complex fracture surface area (Daneshy, 2010).

Although Marcellus shale is generally characterized by relatively high quartz contents (60%) and relatively low clay content (muscovite-illite 30%, kaolinite 2.4%) relative to some other shale, hydrophilic clay content in shales may contribute to water retention in shale through adsorption and pore throat constrictions due to swelling (Boyce and Carr, 2009). Nevertheless this mechanism is likely to contribute somewhat to injected water retention and could result in permanent retention.

Recently, Daneshy and others have theorized that the dominant factor responsible for water retention in naturally fractured shale is simply the interaction of three types of induced fractures: tensile, sliding shear and twisting (Daneshy, 2010). Tensile fractures that grow perpendicular to the least in-situ stress and that have historically formed the basis of standard design models are the easiest to initiate and close easily when injection pressure ceases. This type of fracture would probably not retain significant water except by the leak-off mechanism previously discussed since most water would be easily expelled upon closure of unpropped fractures after stimulation pressures are released.

In contrast, the sliding shear and twisting type fractures are created by shear forces resulting from higher pressure and both tend to close less readily than tensile fractures. These sliding shear and twisting fractures can also act to prevent tensile fracture closure. These shear fractures are often created by interaction between planes of weakness due to the pre-existing natural fracturing and they act to locally divert the fracture into complex branching patterns where significant fluid can be stranded in complex fracture networks (Dahi-Taleghani, 2009). When the width of the branch fractures is narrow enough, the capillary forces can also contribute to keeping the water permanently trapped in place.

Another proposed water trapping mechanism occurs when the fluid is trapped in proppant packs while gas flows around the pack instead of through them (Daneshy, 2010). Since the fracturing fluid is higher density than the gas, any mobile water will displace to the bottom of the fracture and within a short period of time, the local flow velocity is not sufficient to lift the fracturing fluid. This leaves the water trapped at the fracture bottom and may partially explain why water recovery is much more efficient early in production while fluids are moving at higher rates (Daneshy, 2010).

In addition to retention mechanisms, the fracturing pressures which could potentially drive fluid from the target shale formation toward an aquifer are only applied for short periods of time (hours for each stage), while the required travel time for fluid to flow from target to a shallow aquifer under continually hydraulically induced pressure gradients is measured in years. This is the inverse of an injection disposal well where injection pressure is continual and ever-increasing. Calculations done by ICF showed that the maximum rate of seepage under continual injection pressure in the absence of fractures through strata lying above the target shale zone under ideal flow conditions would be substantially less than 10 ft/day or 5 in/hr of pumping time during sustained stimulation pressures (ICF, 2009). Even if the water could be moved, the developable shale formations are typically separated from potential shallow aquifers by thousands of feet of relatively impermeable laminated strata requiring decades or more of continual pressure application to move fluid that distance. Continually decreasing well pressure during production also implies that eventually there would be little energy to move fluid through the low permeability shale and thus trapped for geologic time. Water outside the zone of influence would have neither permeability pathway nor sustainable pressure differential to move fluid either.

Additionally, the volume of fluid used to fracture a well could only fill a small percentage of the void space between the deeper target formation and the shallow aquifer. The already highly diluted chemicals (typically about 1,000 gallons per million gallons of fresh water) would be further diluted by the formation water and the void space above. Assuming an average of 10% porosity above the target zone, the void volume for each 1,000 foot column below the aquifer would be greater than 32 million gallons per acre (ICF, 2009). Obviously, the deeper the target zone, the higher the void volume and dilution factor. A typical Marcellus well with 160 acre drainage (8 wells per 1280 spacing unit) at 3,000 feet of separation from the USDW would contain approximately 15.4 billion gallons of saline water thus introducing a significant dilution factor on the already highly diluted stimulation fluid. Presumably some of the chemicals in the additives used in hydraulic fracturing fluids would also be adsorbed to and bound to the organic-rich shales or decompose with time, temperature and fluid interactions within the hot saline formation waters.

From a fluid flow perspective, any chance of flow toward an aquifer through the remote chance of a conductive open fault to the shallow aquifer or through an unplugged wellbore would be reversed when the horizontal well is produced subsequent to fracture stimulation. Any residual fluid would be further flushed by flow back toward the production zone and into the well bore as pressures decline in the reservoir during production. In any event an experienced stimulation engineer would recognize any unusual occurrence as an anomalous change in injection rate and pressure thus forcing stimulation cessation. The historical experience of hydraulic fracturing in tens of thousands of wells is consistent with the analytical conclusion.

Even though stranded water is likely either immobile or directed toward the producing well, it is prudent to examine the potential height of induced fractures. Prior attempts to address fracture height containment were focused on formation elastic properties and the theory that the higher Young's modulus can act as a barrier to fracture propagation. More recent experiments indicate that elastic moduli contrasts are insufficient to stop vertical growth although they may help in redirecting and changing fracture width and conductivity. Daneshy and others have argued that blunting at the fracture tip, especially in naturally fractured shales, is a more plausible explanation for observed fracture height containment that typically exceeds modeling predictions (Gu, 2008). The mechanism is not yet well modelled but has been observed in coal mines and indicated by microseimic mapping (Daneshy, 2010). Other authors postulate that in-situ stress in layered formations (cookie effect) is the more controlling fractures resulting in shear dampening. (Lewis, date unknown)

While the mechanisms for controlling fracture height have been widely discussed and investigated, direct evidence that induced fracture heights are limited is now abundant through micro-seismic monitoring. This was recently illustrated convincingly by Fisher for both Marcellus and Barnett shale stimulations where an extensive micro-seismic database demonstrated consistently large separation between the deepest groundwater sources and the shallowest induced fracture (Fisher, 2010). This is not surprising given theories that shear failure (slippage) results in blunting of the fracture tip thus limiting vertical growth via fracture reorientation near an interface. However, while such newer theories minimize the historical Young's modulus contrast contribution, it is interesting that the Fisher data show Marcellus fracture growth essentially confined within roughly the bounds of the underlying Onondaga limestone and overlying Tully which had been historically theorized as bounding layers because of high elastic modulus. Whether this is simply coincidence is unknown.

In any event, induced fractures do not appear to extend far above the target zones and the injected water that does not return to the surface through production is likely trapped by a combination of capillary, geo-mechanical-proppant stranding and adsorption mechanisms which render the injected water essentially immobile. Unlike shallow coal seams where fluids may be injected in close proximity to the aquifers and thus may migrate through the aquifer, the deeply buried shales have extremely low permeability and low vertical fluid flow potential. Once the stimulation pressures, lasting only a matter of hours to days are released, fluid flow within the zone of influence is toward the wellbore pressure sink so that even if water was mobile it would move preferentially toward the wellbore.

While development depth is a factor to consider in high volume stimulations, operators indicate that that large volume fracture stimulation of shales at depths less than approximately 3,000 feet are unlikely and even if small stimulations eventually occur at shallower depths, the induced fractures begin to curve from vertical to horizontal because the least principle stress direction rotates to vertical at depths less than approximately 2000 feet. Some states such as NY have already proposed a site specific review of large volume stimulations (>80,000 gallons) whenever the target formation is less than 2000 feet deep or within 1000 feet of the deepest potential fresh water supply. Extensive ongoing water well testing is also proposed to monitor any changes in the drinking water sources.

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