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Technical Issues Related to Hydraulic Fracturing and Fluid Extraction/Injection near the Comanche Peak Nuclear Facility in Texas

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Approved by: ______________________ Date: 12-03-07
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This data report presents the work commissioned to Dr. Ellen Rathje and Dr. Jon Olson, University of Texas-Austin, to assess hazards associated with oil and gas production in the vicinity of the Comanche Peak site. The report contained herein is the final paper provided and serves as input into Subsection 2.5.1.2.5.10 of the FSAR for Units 3 and 4, which addresses man-made hazards. Statements and conclusions presented are considered to be expert opinion. No formal calculations have been produced in support of these statements.

Technical Issues Related to Hydraulic Fracturing and Fluid Extraction / Injection near the Comanche Peak Nuclear Facility in Texas

Ellen M. Rathje and Jon E. Olson

1. Introduction

This report identifies potential issues related to hydraulic fracturing and fluid extraction/injection near the Comanche Peak Nuclear Facility in Somervell County, Texas. Hydraulic fracturing of a gas-producing formation is a well stimulation technique widely used to improve production rates in low permeability reservoirs. Fluid extraction involves the long-term production of the gas from a gas-producing unit, while fluid injection involves the disposal of water or liquid waste into geologic units. Two potential issues related to hydraulic fracturing and three potential issues related to fluid extraction/injection have been identified and are discussed in this report.

2. Geologic Setting

The Comanche Peak facility is located in north Somervell County within the Fort Worth Basin (Figure 1). Fluid extraction in this area involves gas production from the Barnett Shale, which is a low porosity ($n < 5\%$; Mayerhofer et al. 2006, Loucks and Ruppel 2007) and very stiff unit (shear wave velocity ~ 8,000 ft/s, $G \sim 2\text{x}10^6$ psi, $E \sim 5\text{x}10^6$ psi – derived from log data, see Appendix A). The Barnett Shale is located about 1,666 m (5,500 ft) below the surface and is approximately 150 m (500 ft) thick.

Gas production within the Barnett Shale has increased significantly over the last ten years (Figure 2), although other Paleozoic units in the Fort Worth Basin have been producing oil and gas for several decades (Texas Railroad Commission). Oil and gas well locations in the Fort Worth Basin, as well as the extent of the Barnett Shale, are shown in Figure 1. There are few wells in Somervell County, but activity can be seen immediately north in Hood county. More detailed gas well locations, along with production rates, are shown in Figure 3 for the area immediately surrounding the Comanche Peak facility. These data also indicate that current local production is concentrated in Hood County, particularly to the northeast of Comanche Peak. Nonetheless, it is possible that wells could become more abundant in Somervell County if the reservoir conditions are favorable.

Because of the low porosity of the Barnett Shale, enhanced production techniques are required to achieve enough gas production to make the process economically feasible. Thus, hydraulic fracturing is commonly employed. Hydraulic fracturing is a process that involves injecting fluid into the gas-bearing strata to induce fractures that allow the gas to flow more easily to the production well. These induced fractures are on the order of 0.1 to 0.25 in. thick and filled with sand or other high permeability materials (called proppant) so that they remain open and can conduct the gas to the well.

Fluid injection is also a common subsurface operation in the Fort Worth Basin. Typical injection operations consist of the disposal of associated water produced with oil and gas or hydraulic fracture water recovered in the well clean-up process. In 2002 (the latest data available from the Texas Railroad Commission online), there was no injection in Somervell County and volumes in adjacent counties were small, but nearby Palo Pinto county had a 2002 injected volume of 4,700,000 barrels (see Table 1 for injected volumes in counties adjacent to Somervell).

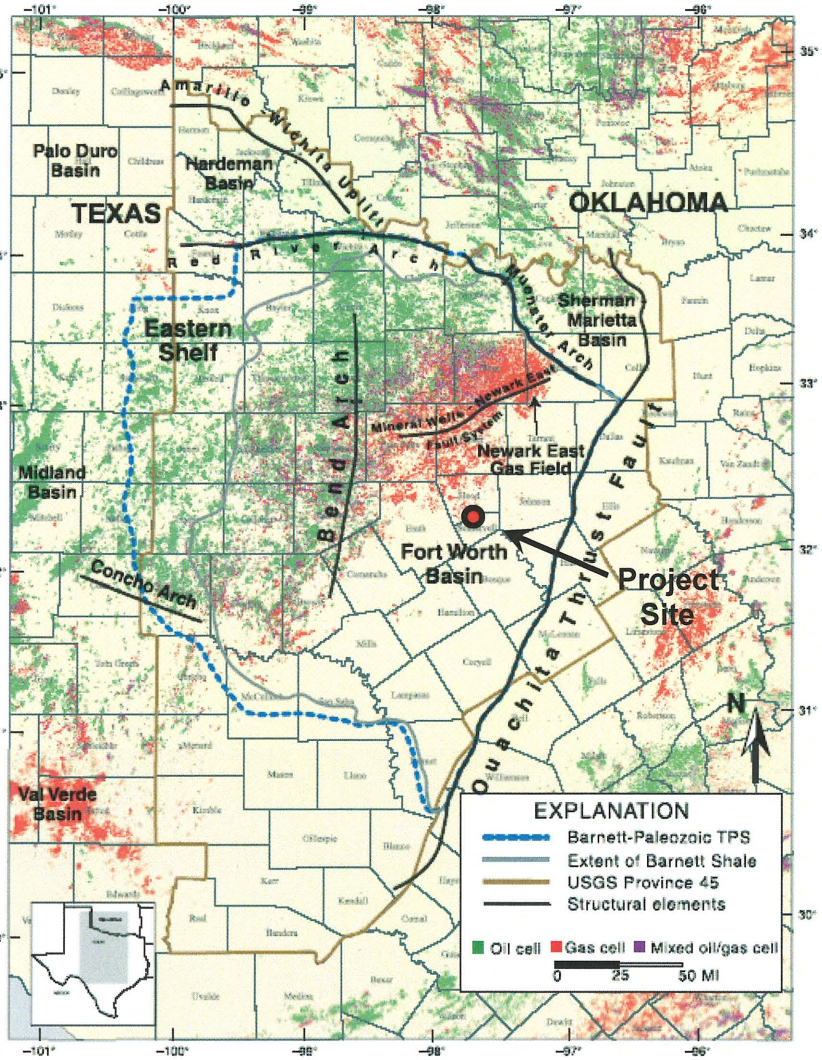

Figure 1. Geologic setting of study area (from Pollastro 2007)

Table 1. 2002 Injected Volumes in Counties Adjacent to Somervell

County	Injected Volume, bbls
Bosque	0
Hood	29,000
Erath	300,000
Johnson	0

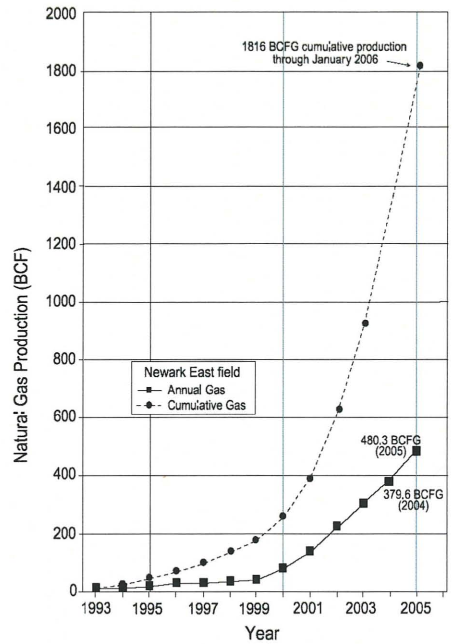

Figure 2. Gas production from the Newark East field in the Barnett Shale (from Pollastro 2007)

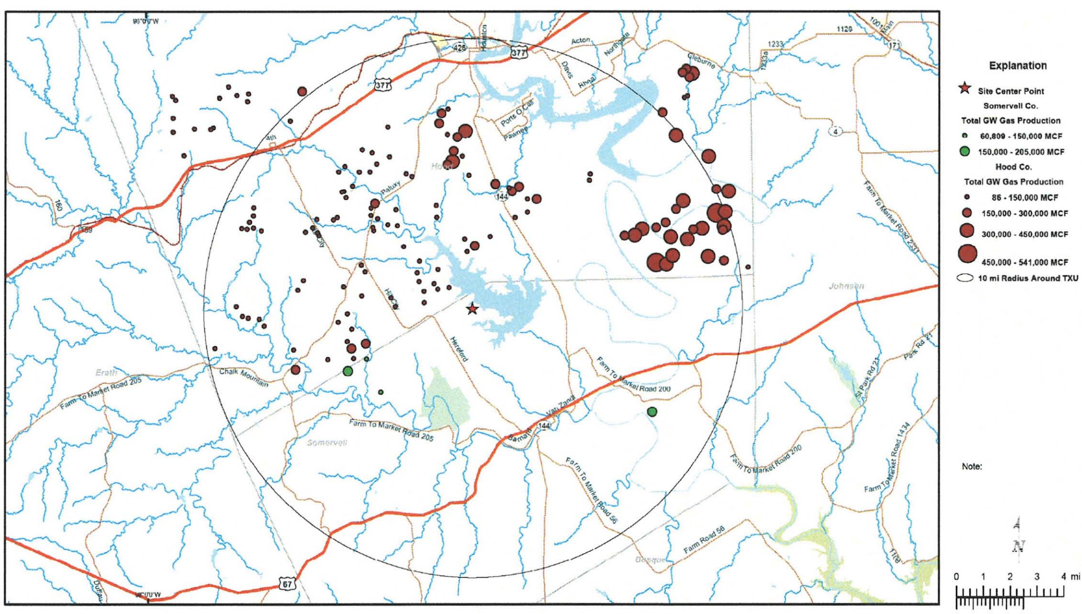

Figure 3. Gas production wells in the vicinity of the Comanche Peak facility (from WLA).

3. Technical Issues Related to Hydraulic Fracturing

Two potential issues have been identified related to hydraulic fracturing: changes to the rock properties and induced seismicity. These issues are discussed below.

3.1. Changes to rock properties

A hydraulic fracture is idealized as a single vertical plane of hundreds to a few thousand feet in total length, hundreds of feet in height, and a fraction of an inch in width. The actual size of a hydraulic fracture will depend largely on the amount of fluid and sand injected, the permeability of the formation, and the variation of the minimum horizontal stress over depth (which determines whether the fracture is contained in height growth or not). Hydraulic fracture diagnostic data from microseismic monitoring in the Barnett Shale suggests that hydraulic fracture growth is more complex than the simple idealization, with multiple strands forming as the propagating hydraulic fracture interacts with pre-existing natural fractures (Gale et al., 2007). Although there is no direct observation of subsurface hydraulic fracture geometry for the Barnett Shale, it is presumed that the created fracture approximates an orthogonal grid-like pattern (Coulter et al. 2004, Fisher et al. 2004), with minimum spacing on the order of 50 ft between fracture zones (which may be narrow vertical corridors of closely spaced fractures).

Rock fractures generally reduce the wave propagation velocities of rock (e.g., Pyrak-Nolte et al. 1990). Leucci and De Giorgi (2006) showed that for a fracture spacing of about 0.5 m and high-frequency waves (> 1 kHz), the shear wave velocity was reduced by about 30% for a sedimentary rock specimen under atmospheric pressure. Fratta and Santamarina (2002) provide a relationship (called Backus' average) that predicts the wave velocity of fractured rock (with the fractures filled with a material distinct from the intact rock) based on the characteristics of the rock and fracture infill material ratio. The velocity of the fractured rock is a function of the fracture ratio (equal to the fracture thickness / spacing between fractures), the velocity of the intact rock, the velocity of the fracture infill material, and the density of the intact rock and fracture infill material. Considering the intact shear wave velocity of Barnett Shale (8,000 ft/s) and assuming a shear wave velocity of 800 ft/s for the proppant filling the fractures and a fracture ratio of 0.0004 (fracture thickness = 0.25 in, fracture spacing = 50 ft = 600 in), the model presented in Fratta and Santamarina (2002) predicts less than a 5% reduction in shear wave velocity due to the fracturing.

Because of the broad spacing between fracture zones and the fact that they are filled with proppant and thus presumed to have high resolved compressive stress across them, it is unlikely that the induced hydraulic fractures will substantially alter the velocity structure of the formation. Finally, the standard practice for locating microseismic events caused by hydraulic fractures presumes the same velocity structure before, during and after the hydraulic fracture treatment, which lends support to our interpretation.

3.2. Induced seismicity

Induced seismicity caused by hydraulic fracture treatment injections is expected to be below measurable levels and thus of no danger to surface structures. Albright and Pearson (1980) reported magnitudes on the order of -6 to -2 for micro-earthquakes associated with injection related fracturing for hot dry rock applications, while Maxwell et al. (2006) reported moment magnitudes between -1.5 and -3.5 for hydrofracturing in the Barnett Shale. Conventional hydraulic fracture treatments as conducted for Barnett Shale gas production are expected to have the same level of seismicity. Finally, there are no known instances of hydraulic fracturing causing a damaging earthquake (Majer et al. 2007).

4. Technical Issues Related to Fluid Extraction/Injection

Three potential issues have been identified related to long-term fluid extraction or injection in the Comanche Peak area: changes to the rock properties due to the gas production, induced compaction/subsidence due to gas production, and induced seismicity due to gas production and fluid injection. These issues are discussed below.

4.1. Changes to rock properties

The extraction of gas changes the effective stresses in the gas-bearing strata due to a reduction in fluid pressure. This increase in stress can cause compaction (i.e. reduction in porosity / void ratio), as well as permanently increase the shear modulus / shear wave velocity of the rock. However, as mentioned above, because the Barnett Shale is very low porosity and has a large stiffness, it is unlikely that rock properties will change appreciably over the production life of the reservoir.

4.2. Induced Compaction/Subsidence

The compaction of the gas-bearing strata due to gas extraction can cause subsidence at the ground surface. The magnitude and extent of this surficial subsidence is affected by various factors, such as the depth of the gas-bearing strata, the thickness of the strata, the properties of the strata, production rates, and the details of the extraction process. Using the properties for the Barnett Shale derived from nearby log data (see Appendix A) and assuming a 207 bar (3,000 psi) reduction in fluid pressure in the reservoir (the expected maximum drawdown), the computed elastic compaction for the 150-m thick shale layer was on the order of 0.06 m (0.2 ft). These calculations can be found in Appendix B. Because this level of compaction is small and the Barnett Shale reservoir is fairly deep (>1500 m), the associated subsidence at the ground surface is expected to be negligible.

4.3. Induced Seismicity

4.3.1. Background

Small earthquakes (magnitude less than about 5) can be induced by fluid (gas, oil, or water) extraction (e.g., Yerkes and Castle 1976, Segall 1989, Frohlich and Davis 2002) or fluid injection (e.g., Seeber et al. 2004, Majer et al. 2007). There are almost no cases of human actions causing large earthquakes (Frohlich and Davis 2002).

The mechanism for induced seismicity due to fluid extraction is not immediately intuitive because the removal of fluid decreases pore pressures and increases effective stresses, a change that is generally expected to stabilize faults because it restrains slip (Segall 1989). However, the general consensus is that poroelastic changes in the in situ stress state are the driving cause of induced seismicity due to fluid extraction (e.g., Segall 1989, Van Eijs et al. 2006). The most notable location of seismicity induced by gas or oil extraction is the Lacq gas field in France, which experienced 44 earthquakes with $M_l > 3$ and 4 events with $M_l > 4$ over a twenty year period (Grasso and Wittlinger 1992, Maury et al. 1992). There have been some earthquakes in south-central Texas that have been related to local gas and/or oil extraction. The largest of these earthquakes was the 9 April 1993 m_bLg 4.3 event that occurred 80 km south of San Antonio with reported modified Mercalli intensities (MMI) as high as VI (Davis et al. 1995). The most significant damage occurred at the Warren Petroleum Plant, and included cracking of reinforced concrete foundation blocks, failure of one pipe connection, damage to steel bolts, and horizontal movement on the order of several centimeters. Frohlich and Davis (2002) estimate that of the 130 earthquakes that have occurred over the last 150 years in Texas and have been felt by residents, only 22 were induced by gas or oil production. Additionally, it is important to note that there has been significant gas and oil production within the state of Texas over the last century, including within the Fort Worth Basin, yet the seismicity rate remains relatively low (Frohlich, personal communication). In particular, the Texas seismicity catalog generated by William Lettis and Associates for the time period 1627 to 2006 shows no earthquakes greater than m_b 3 within the Fort Worth Basin.

The mechanism for induced seismicity due to fluid injection is the reduction in effective stress (due to increased pore pressures) and subsequent weakening of faults (Majer et al. 2007). The most notable example of seismicity induced by fluid injection is the seismicity associated with waste fluid injection at the Rocky Mountain Arsenal near Denver, Colorado in the mid 1960's. Here, 35 earthquakes greater than m_b 3 and three earthquakes greater than m_b 5 occurred over a five year period (Healy et al. 1969). The rate of injection in this area was approximately 50 to 60 million gallons per year over a three-year period. We found only one example of injection induced seismicity in Texas: the earthquake sequence associated with the Cogdell oil field of west Texas (Davis 1989, Davis and Pennington 1989). These earthquakes occurred in the Midland Basin in an area of fluid injection associated with secondary oil recovery (waterflooding). The net fluid injection in this area was 250 to 500 million gallons per year between 1960 and 1970, and was increased to 500 to 1,000 million gallons per year between 1970 and 1977. Over the time period from 1974 to 1982 seventeen earthquakes greater than m_b 2 occurred, including a m_b 4.3 earthquake in 1978. This earthquake induced minor damage and the maximum MMI was reported as V (Frohlich and Davis 2002). It is important to note that the injection rates at Codgell are an order of magnitude greater than the rates injected at Rocky Mountain Arsenal, yet the induced rate of seismicity and the size of events were considerably smaller.

4.3.2. Approaches to Assess the Potential for Induced Seismicity

It is relatively straightforward to determine whether an increase in observed seismicity is related to gas or oil production or fluid injection. In these cases, researchers consider the temporal relationship between the increase in seismicity, the initiation of production/injection, and the change in fluid pressure within the field (Davis et al. 1995). Additionally, seismologists consider the hypocentral locations of the earthquakes relative to the location of the gas or oil field/injection unit, as well as the presence of existing local faults (active or inactive) that can accommodate slip.

Conversely, it is difficult to predict a priori whether gas or oil production / fluid injection within a specific geologic unit will induce earthquakes. Empirical or analytical approaches have been proposed for this purpose, as discussed below.

Empirical Approach. Van Eijs et al. (2006) provide a quantitative, although empirical, methodology to predict the potential for induced seismicity due to future gas production. This methodology is based on an empirical model developed from observed seismicity and the characteristics of local gas reservoirs and production in the Netherlands. The empirical model relates the probability of induced seismic activity to three parameters related to the local reservoir and faulting characteristics: the pressure drop in the reservoir (ΔP), the stiffness ratio between the seal rock and reservoir rock (S), and the fault density (F). Using observations from 124 production fields, Van Eijs et al. (2006) derived thresholds for ΔP, S, and F related to the occurrence of induced seismicity. The most favorable conditions for future induced seismicity are represented by $\Delta P \geq 72$ bar, $S > 1.34$, and $F > 0.98$, with the corresponding probability of induced seismicity being equal to 0.52.

Although the Van Eijs et al. (2006) model was derived for a different geologic region, its application to the Fort Worth Basin provides a preliminary estimate of the potential for induced seismicity around Comanche Peak. Pressure drops (ΔP) larger than 72 bar (1050 psi) certainly are possible in the Fort Worth Basin based on initial reservoir pressures in the Barnett Shale of 200 bar (3,000 psi) or more (Frantz et al. 2005). The stiffness ratio (S) between the Barnett Shale and the overlying Marble Falls Limestone is close to 2.0 (derived from log data, see Appendix A), which meets the Van Eijs et al. (2006) threshold. Various information can be compiled to assess the fault density (F). The tectonic map of Texas (Figure 4) indicates a normal fault that extends approximately 50 miles from Tarrant County through Johnson County and into Somervell County. Within the Fort Worth Basin many NE-SW trending faults are observed within the outline of the Newark East Field that cut the base of the Barnett Shale (Figure 5). Two of these faults are within 10 miles of the Comanche Peak Facility. None of the faults in Figure 4 appears to reach the surface as mapped at 1:250,000 scale on the Geologic Map of Texas, Dallas Sheet, suggesting they are all pre-Cretaceous with regard to their time of activity. Figure 1 indicates that the nearest major fault (inactive) to the Comanche Peak facility is the Mineral Wells Fault, which is 60 miles north and extends from central Palo Pinto County ENE through Parker County to Wise County. Based on these data, local faults are present that could accommodate slip under certain conditions. However, the fault density (as defined by Van Eijs et al. 2006) for the region immediately surrounding Comanche Peak is estimated to be very low (<0.1). Despite values of ΔP and S that are favorable for induced seismicity, the small value of fault density ($F<0.1$) indicates a low probability of induced seismicity based on the Van Eijs et al. (2006) model. However, a more detailed assessment should be performed by WLA personnel.

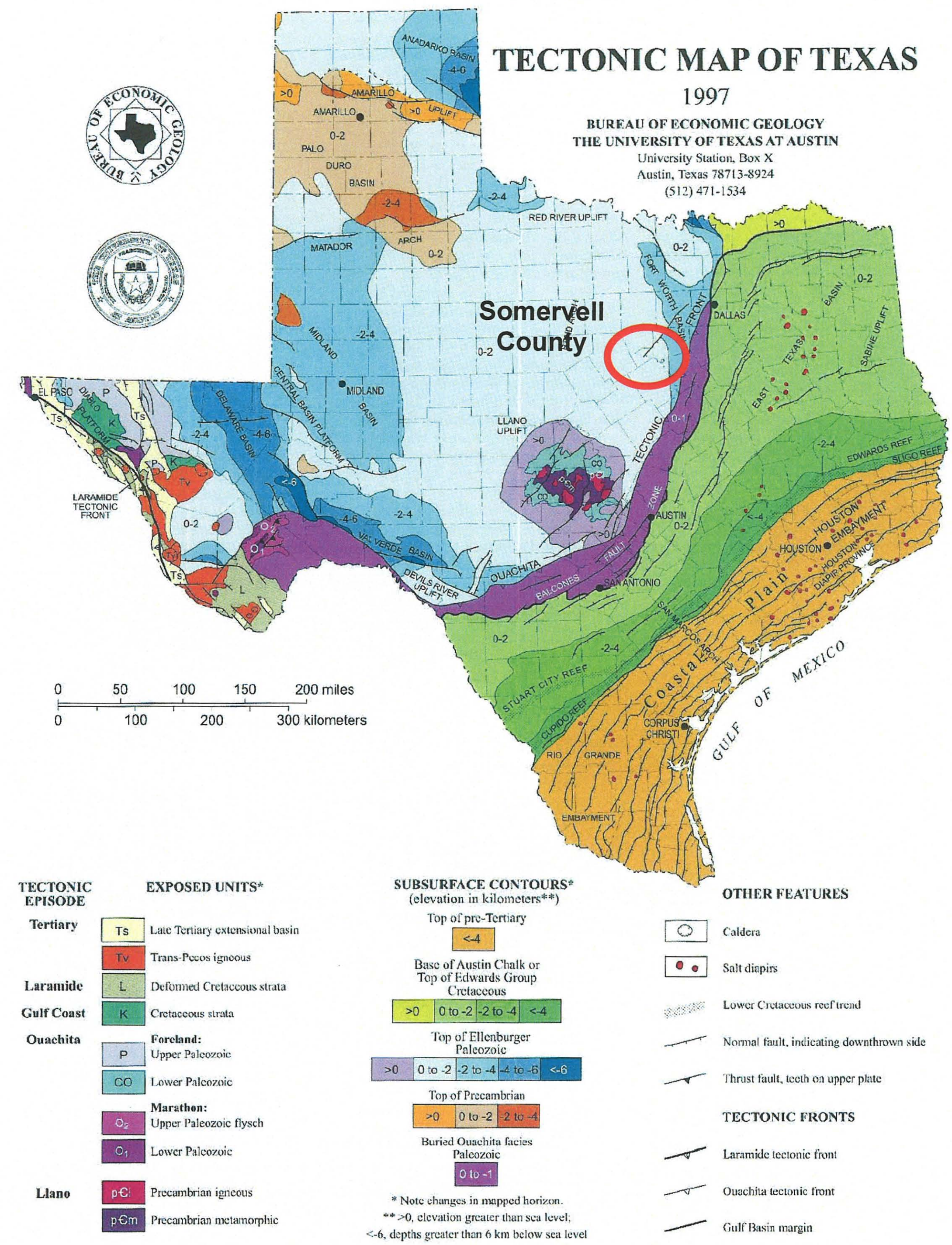

Figure 4. Tectonic Map of Texas
(Bureau of Economic Geology, University of Texas at Austin)

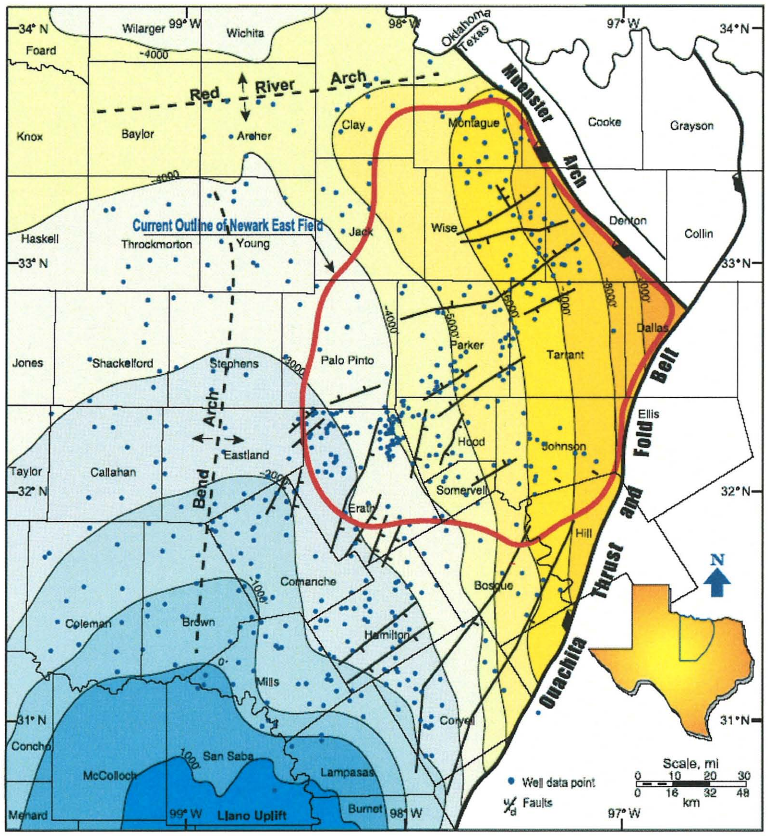

Figure 5. Regional geology and general structure at the base of the Barnett Shale (Zhao et al. 2007)

In terms of predicting design ground motions for seismicity induced by gas production, Van Eck et al. (2006) used probabilistic seismic hazard analysis (PSHA) to evaluate the seismic hazard within the Netherlands due to induced seismicity from gas production. In this analysis, the magnitude-recurrence relationship was modeled as truncated exponential and the model parameters were derived from the observed seismicity over a 17 year period ($M_{L,min}$ = 1.5, $M_{L,max}$ = 3.5). Using a modified version of Campbell (1997), the seismic hazard for peak ground acceleration was evaluated for return periods of 10 and 100 years. These return periods are short, but the authors argue that these short return periods are appropriate because gas production usually extends for only a few decades. The resulting ground motions for 10 and 100 year return periods are quite large (0.25 to 0.45 g) at distances of 0 km, but attenuate to below 0.1 g at distance greater than about 5 km. These PGA levels are quite large, but the corresponding values of peak velocity are on the order of 4 to 7 cm/s indicating that the ground motions are rich in high frequency and thus less damaging.

Analytical Approach. The analytical approach to predicting fluid injection or withdrawal induced earthquakes is based on assessing the effective and total stress changes in and around a producing reservoir and analyzing that stress change with respect to a failure criterion for fault slip. Segall and Fitzgerald (1998) outline a method where they model a finite, elliptical shaped reservoir in a two-dimensional half-space and compute the in situ stress variations induced by pore pressure change. They then evaluate the stress change in the context of a Coulomb friction criterion for slip on pre-existing faults.

Pore pressure changes in the reservoir can promote earthquakes in the reservoir itself or in the surrounding rock. In areas where the in situ stress is conducive to normal faulting (i.e., the vertical stress is the maximum principal stress), such as the Fort Worth Basin, Segall and Fitzgerald (1998) state that normal faulting within the reservoir may be induced by the poroelastic shrinkage associated with pore pressure reduction. This shrinkage increases the shear stresses in the rock, which promotes slip. However, slip and associated earthquakes are promoted only under certain conditions with respect to reservoir mechanical properties because pore pressure reduction also increases effective stresses and reduces the tendency for faults to slip. Using the mechanical properties derived from the Officer's Club #1 well and the equations outlined in Appendix C, we found that it is unlikely that pore pressure reduction in the Barnett Shale will cause earthquakes in the reservoir itself (within the Barnett). The computation suggests that pre-existing faults in the reservoir would be less likely to slip as gas production progresses.

However, based on the analysis of Segall and Fitzgerald (1998), the most likely place for earthquakes to occur in normal faulting regions is just outside the boundaries of the reservoir, where the poroelastic-induced increase in shear stress is still large, but unlike in the reservoir, there is no change in pore pressure. Consequently, there is no competing fault strengthening effect outside the reservoir to counteract the increase in shear stress. This does not guarantee faults will slip on the reservoir periphery – it merely suggests that given sufficient stress changes, the periphery is the region most likely to experience fault slip.

The definition of the periphery or outer boundary of a reservoir can be difficult given the constant infilling and/or expansion of drilled areas. Segall and Fitzgerald (1998) state that the key condition to cause conditions favorable to slip at the reservoir periphery are large gradients in pore pressure. Since the Barnett is an extremely low permeability rock (permeability is on the order of 10 microDarcies), there should be large pressure gradients at the edge of the stimulated (hydraulically fractured) region around every well. Consequently, to some extent (depending on well placement and spacing), every well can be considered to be a test to whether gas production in the Barnett Shale will induce earthquakes. Greater depletion will increase the likelihood of seismicity, but to date (Figure 2 shows production began about 10 years ago and accelerated 5 years ago) there have been no significant seismic events.

The idea that the periphery of the reservoir is the area of greatest seismic risk suggests that it might be detrimental to allow gas production development all around the Comanche Peak site but not within it. This could potentially cause a detrimental concentration of fault slip inducing stresses in the immediate vicinity of the site. Our analysis suggests that the likelihood of significant seismic activity is unlikely even under these conditions, but the analysis of Segall and Fitzgerald (1998) suggests that putting a production exclusion zone within a given radius around the site would not improve the seismic risk factors unless the radius of such a zone was sufficient to guarantee the region of high pore pressure gradient at the edge of production was sufficiently far away from the site so that if an earthquake were produced, its effect would dissipate before reaching the site. Assuming all of the assumptions of Segall and Fitzgerald (1998) are valid, the optimal condition to reduce seismic risk around the site would be uniform pressure reduction throughout the local region to minimize high pore pressure gradients.

As discussed, the Barnett Shale in the Fort Worth Basin is a target for gas production and pressure reduction, but other subsurface formations may be targeted for the injection of fluids (typically water). Water injection may be used for secondary oil recovery (waterflooding) or waste disposal. Because of its large extent, the Ellenburger Limestone, which is stratigraphically below the Barnett Shale, is a prime target for injection. Such injection may increase fluid pressure in the subsurface, reducing the effective stress on faults and promoting slip. As mentioned earlier, there are documented examples of injection-induced seismicity. However, Davis and Pennington (1989) find that even though modeling suggests that reported injection pressures in oil and gas fields under water injection in Texas should cause fault slip, only one field (Cogdell) was known to have seismic activity. Their conclusion to explain the apparent discrepancy between predicted fault failure and known seismicity was that much of the failure actually may be aseismic. In addition to changing the stress state, the injected fluid is suspected to weaken the faults to such an extent that they creep to relieve shear stress.

4.3.3. Induced Seismicity Relative to PSHA Model for Comanche Peak

Current procedures used to perform PSHA for nuclear facilities incorporate background seismicity zones (C. Fuller, WLA, personal communication). The earthquake recurrence models for these background seismicity zones are derived from the observed earthquakes with body wave magnitudes (m_b) greater than 3.0. However, the minimum m_b magnitude that is considered to be of engineering significance is 5.0, and smaller magnitudes are not considered in the PSHA analysis to derive design ground motions.

It is very uncommon for induced earthquakes to exceed m_b 5.0. However, the earthquakes induced by injection at the Rocky Mountain Arsenal were larger than 5.0, so it is important to consider what characteristics might be favorable to generating earthquakes larger than 5.0. In the case of the Rocky Mountain Arsenal, injection took place in naturally fractured, otherwise non-porous, Precambrian crystalline rock (Hsieh and Bredehoeft, 1981). In such a situation, where there is little to no pressure diffusion into the pore space, injected fluid would be confined strictly to flow within the natural fractures, and thus could reduce effective stresses over very large fractures areas. Larger magnitude earthquakes require large slip areas, so injection into naturally fractured crystalline rock might reasonably be expect to result in larger induced earthquake magnitudes. Although the Barnett Shale and the Ellenburger limestone of the Fort Worth Basin are competent sedimentary rocks, the crystalline rocks of Colorado would be much stronger. Greater rock strength (and stiffness) allows for greater build-up of stress that can cause larger earthquakes. Finally, Healy et al. (1969) suggest that the Rocky Mountain Arsenal injection was releasing built up tectonic stress locked in the rock. Because the Denver area is one of more recent tectonic activity (the Laramide Orogeny, ended ~25 mya, and ongoing post-Laramide uplift) than the Fort Worth Basin (last major tectonic event was the Ouchita Orogeny which ended ~300 mya), the shear stress magnitudes and active tectonic strain rates are expected to be larger in Colorado than in North Texas, and consequently this may limit potential earthquake magnitude.

Based on the information collected, it appears very unlikely that any earthquake induced by gas production or fluid injection in the Fort Worth Basin would be larger than m_b 5.0, and therefore the enhanced seismicity that potentially would be induced would not need to be taken into account in the PSHA.

5. Recommendations

Various issues have been identified related to well stimulation, long-term gas production, and long-term fluid injection in Fort Worth Basin near the Comanche Peak facility. The only issue that presents any concern is induced seismicity due to gas extraction from the Barnett Shale or fluid injection into the Ellenburger Limestone.

It is judged unlikely that seismicity will be induced in the Fort Worth Basin as a result of gas production or water injection based on the following: (1) although Texas has had intense oil and gas activity, as well as fluid injection, for nearly 100 years, there have been very few instances of associated seismicity, and none documented in the Fort Worth Basin of m_b 3 or greater, and (2) the technical assessment of the potential for fault slip in the Barnett Shale due to gas production is low. Additionally, even under the most favorable conditions, the largest earthquake that likely would be induced would be on the order of m_b = 4.0 to 4.5 (based on observed, human-induced seismicity within Texas), yet these magnitudes are smaller than the minimum magnitude considered in PSHA for nuclear facilities.

Our final technical recommendations for the Comanche Peak facility include:

- Develop a local seismic monitoring program that can detect small earthquakes (m_b = 1 to 3). Monitor the location and size of each earthquake, and periodically (i.e. every six months) investigate whether the rate of seismicity is changing. Because fluid injection slowly builds pressure in a reservoir, it is likely that seismicity, if conditions were favorable for it to occur, would build in intensity with time, allowing remedial action before an event of damaging magnitude would occur.
- A moratorium on injection within a certain distance of the site might be considered to reduce potential future risk of induced earthquakes. Such a restriction should have little economic effect on the region (this is not limiting economic development of a resource), so it seems a reasonable measure considering the uncertainty in assessing the true risk.
- The production of gas development should be allowed to proceed naturally to avoid the project site being a place of pore pressure gradient which could potentially increase the risk of seismicity.
- Further study may be warranted to more comprehensively model the potential risk of seismicity along the lines of the methods of Segall and Fitzgerald (1998) and Davis and Pennington (1989). A problem with the modeling approach is the inability to eliminate uncertainty in the input data (in situ stress magnitudes, permeability distributions, locations and condition of pre-existing faults, etc.), so local monitoring of $m_b < 3$ earthquakes is probably a preferable initial route.

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Appendix A. Analysis of Officer's Club #1 Well, Quicksilver Resources, Inc., Newark East Field, Hood County, Texas

Acoustic logs can be readily processed for mechanical properties data, and those mechanical properties can be used to infer in situ stress information (Blanton and Olson, 1999). The magnitudes of the minimum and maximum principal stresses can be used to assess how close a formation is to the Coulomb shear failure envelope. Although such an analysis cannot assess the magnitude of slip or whether the slip will cause an earthquake, it can be used to evaluate whether changes induced by humans may make seismicity more or less likely. This will be discussed in Appendix C.

The Officer's Club #1 well provided compression and shear wave travel times to enable the calculation of elastic mechanical properties. There was no density data available, so a value of 2.5 g/cc was assumed. This assumption could result in an error of 10% or less, as density for the low porosity Barnett is not expected to vary by much, and the elastic moduli depend linearly on density.

The equations used to calculate the elastic parameters were:

$$R = \frac{V_p}{V_s} = \frac{\Delta t_s}{\Delta t_p}$$

$$\nu = \frac{0.5R^2 - 1}{R^2 - 1}$$

$$G = F_{dyn-stat} * 1.34x10^{10} * \frac{\rho_b}{\Delta t_s^2}$$

$$E = 2G(1+\nu)$$

$$K_b = \frac{E}{3(1-2\nu)}$$

$$\alpha_p = 1 - \frac{K_b}{K_g}$$

where R is the ratio of compression to shear wave velocity, ν is Poisson's ratio, G is the shear modulus, E is Young's modulus, K_b is the bulk modulus, α_p is Biot's poroelastic constant, and K_g is the bulk modulus of grain material making up a rock. $F_{dyn-stat}$ is the dynamic to static correction factor, which accounts for the frequency dependence of elastic moduli. For hard rock such as the Barnett, a reasonable assumption is $F_{dyn-stat}=0.9$.

The horizontal stress equations used for the analysis were (Blanton and Olson, 1999)

$$\sigma_{xx} = \frac{\nu}{1-\nu}(\sigma_{zz} - \alpha_p P) + \alpha_p P + \frac{E}{1-\nu^2}\varepsilon_{xx} + \frac{E\alpha_t \Delta T}{1-\nu}$$

$$\sigma_{yy} = \frac{\nu}{1-\nu}(\sigma_{zz} - \alpha_p P) + \alpha_p P + \frac{\nu E}{1-\nu^2}\varepsilon_{xx} + \frac{E\alpha_t \Delta T}{1-\nu}$$

where σ_{xx} and σ_{yy} are the horizontal stresses, σ_{zz} is the vertical stress, P is the pore (reservoir) pressure, α_t is the thermal expansion coefficient (assumed to be $5x10^{-6}/°F$), ε_{xx} is the tectonic strain (determined from calibration data as described by Blanton and Olson, 1999), and ΔT is the geothermal gradient times the depth (accounts for thermal expansion stresses experienced by rock during burial). The vertical stress was computed as the integration of the density data, which in this case was the assumed 2.5 g/cc value over the entire depth range. The log displays follow, but average parameters representative of the Barnett Shale used for other analyses in the report are summarized in Table A.1.

Table A.1. Average Mechanical Properties of the Barnett Shale Interpreted from the Officer's Club #1 Well

E (Young's modulus)	5×10^6 psi
G (shear modulus)	2×10^6 psi
ν (Poisson's Ratio)	0.15
α_p (Biot's poroelastic constant)	0.65
V_p (compression wave velocity)	12,000 ft/s
V_s (shear wave velocity)	8000 ft/s

For the horizontal stress calculations, the reservoir pressure gradient was assumed to be 0.5 psi/ft (Frantz et al., 2005, report a range of 0.45 to 0.52 psi/ft), the geothermal gradient was assumed to be 12°F per 1000 ft (based on the static bottomhole temperature of 135°F at 6250 ft from the Mark IV Energy, Buck Davis No. 1 well in Bosque County), and the average value of the minimum horizontal stress gradient over the Barnett Shale interval was assumed to be 0.6 psi/ft (Fisher et al., 2002; Ketter et al., 2006).

For the calculation of Biot's poroelastic constant, the grain material modulus for the shale section was assumed to be that of quartz, $K_g \cong 6 \times 10^6$ psi. This value was too low to be used for the Marble Falls and Ellenberger Limestones, as the bulk modulus of the rock often exceeded 6×10^6 psi. Since the non-porous grain material that makes up the rock should always be more stiff than the porous assemblage of those grains, a higher grain modulus was used for the carbonate sections, $K_g \cong 6 \times 10^6$ psi.

Another possible source of error in the log analysis is that the pore pressure gradient for the Barnett Shale was used for all other formations as well. The Barnett is slightly overpressured, but we did not find any pore pressure information for the other formations at this locality. In addition, no attempt was made to correct for gas effects on the measured acoustic velocities. It is presumed that for high stiffness, low porosity rock like the Barnett Shale, the correction would be small.

Figure A.1. Velocity profile through the Barnett Shale from the Officer's Club #1 well.

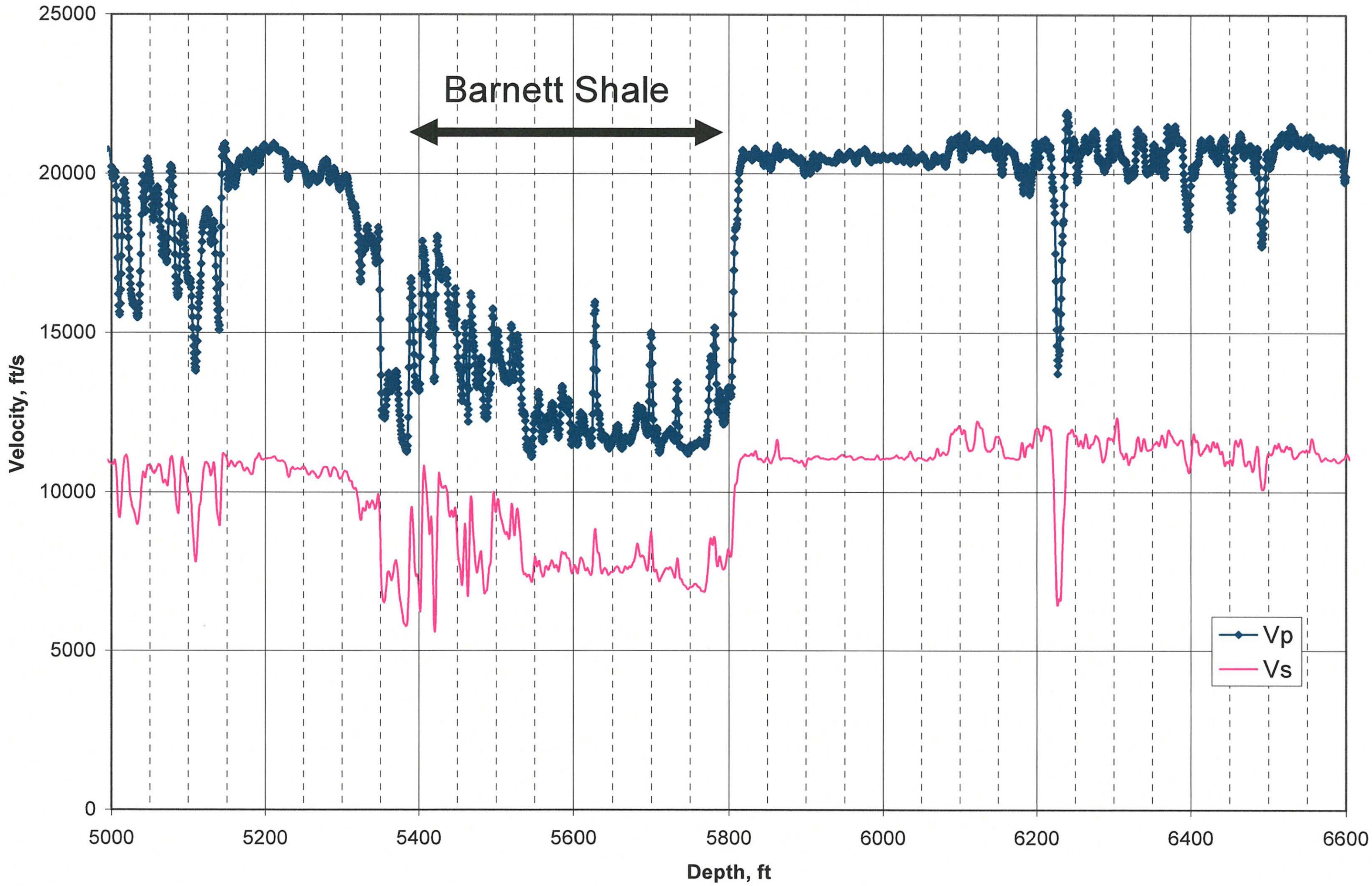


Figure A.2. Elastic moduli through the Barnett Shale calculated from the Officer's Club #1 well.

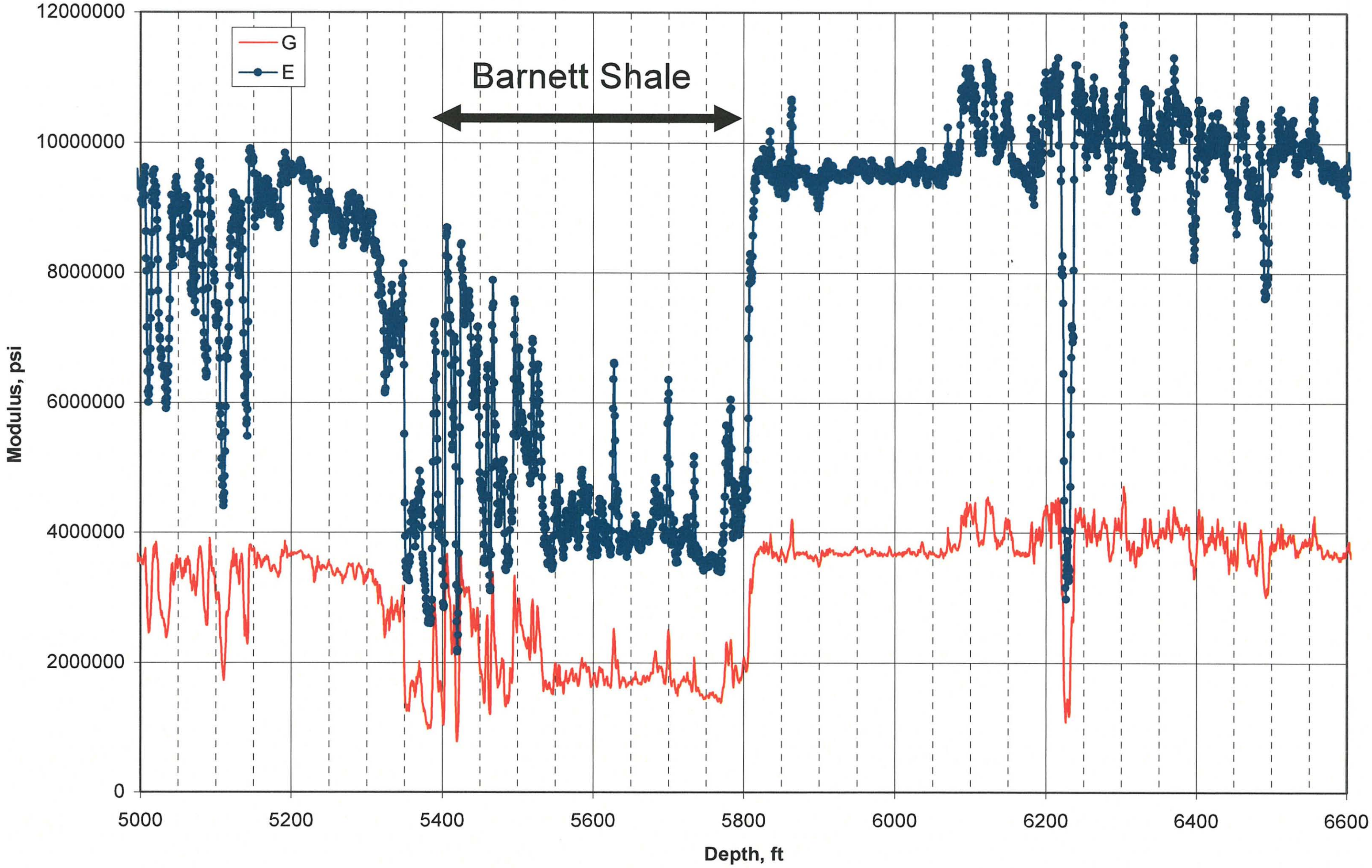


Figure A.3. Elastic constants (Poisson's Ratio and Biot's alpha) and gamma ray profile through the Barnett Shale from the Officer's Club #1 well.

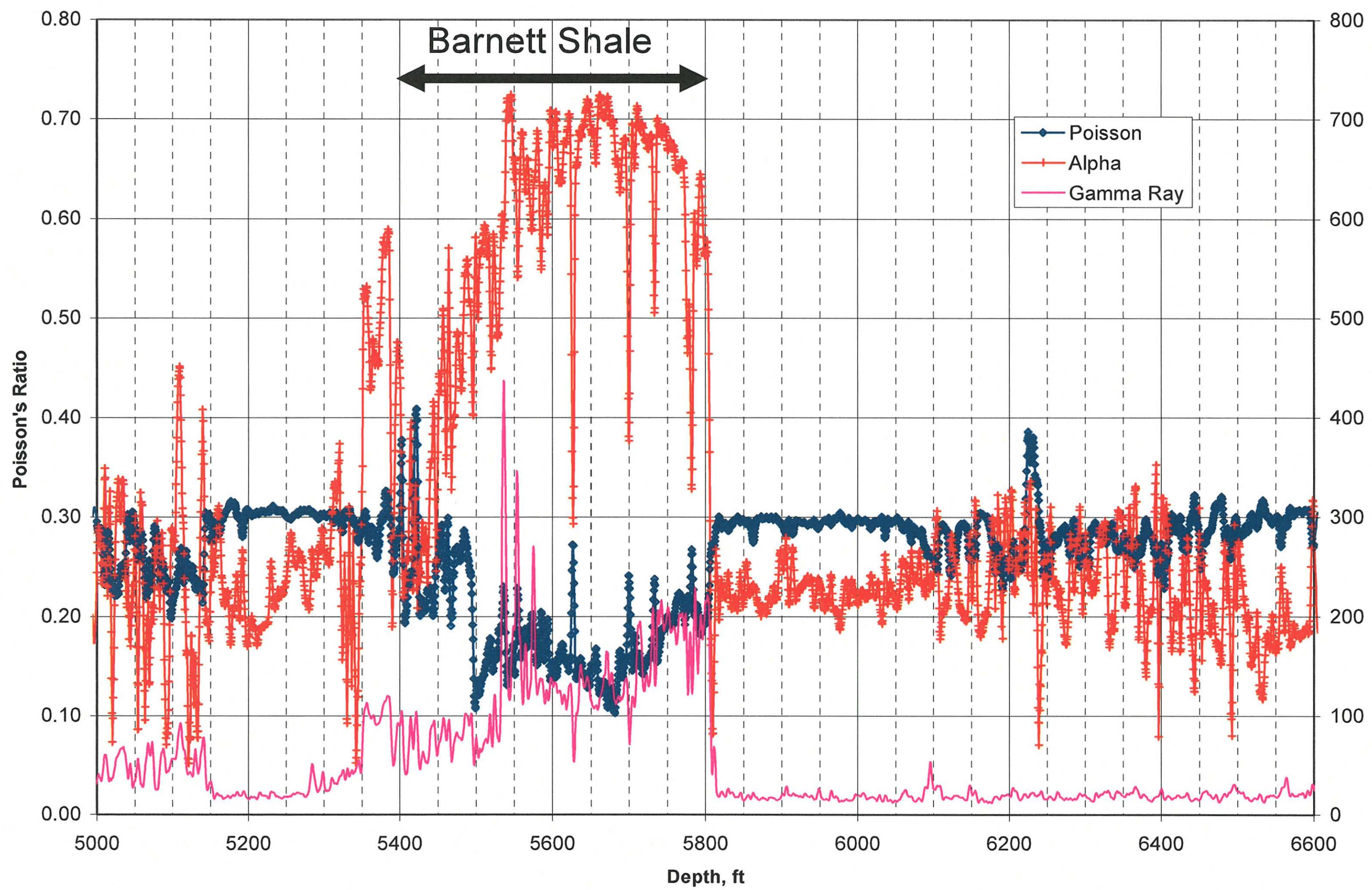
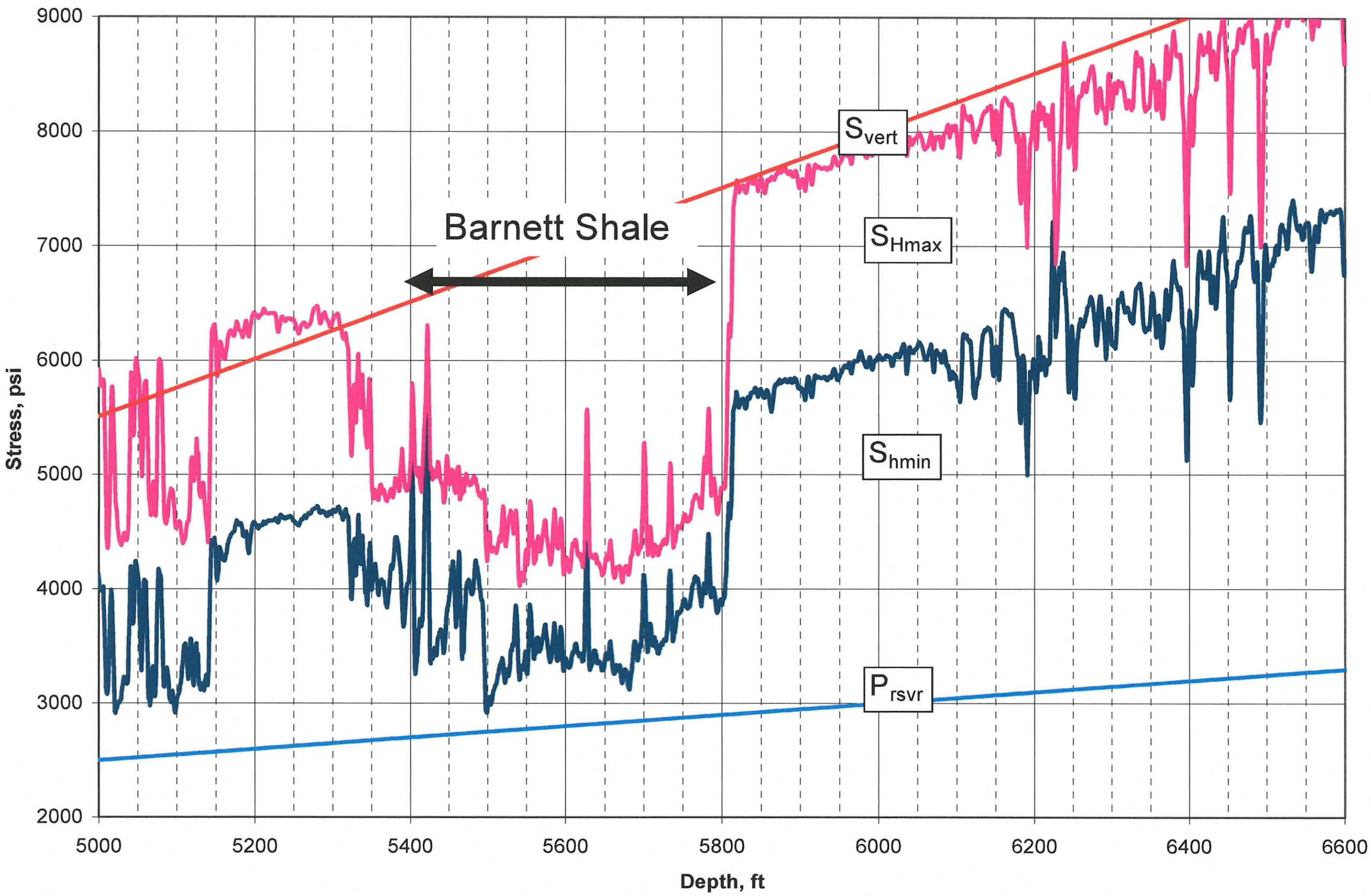


Figure A.4. Interpreted stress profile through the Barnett Shale from the Officer's Club #1 well.



Appendix B. Compaction Calculation for Barnett Shale, Newark East Field, Hood County

Using the mechanical properties data from Appendix A, Table A.1, the expected compaction, Δh, of the Barnett Shale reservoir section was estimated to be 0.18 ft, or a vertical strain of $\varepsilon v = \Delta h/h = 0.18$ ft/500 ft=0.0004. A pressure drop of 3000 psi was used as a worst case value (this would require bringing the reservoir pressure in the Barnett to 0 psi, an unlikely event), and the reservoir thickness was assumed to be 500 ft. The equation used follows Geertsma (1973) and is

$$\Delta h = -h\frac{(1+\nu)(1-2\nu)}{E(1-\nu)}\alpha_p \Delta P \qquad \text{(B.1)}$$

where h is reservoir thickness and ΔP is the pressure change (negative for depletion).

The magnitude of subsidence can also be estimated analytically given the compaction and reservoir geometry factors as outlined by Geertsma (1973). Above the center of a circular disk reservoir (z=0, r=0), the surface subsidence, u_z, can be calculated as a function of the compaction, Δh, as

$$u_z(z=0, r=0) = 2(1-\nu)(1-\frac{\eta}{\sqrt{1+\eta^2}})\Delta h \qquad \text{(B.2)}$$

where

η=D/R,
D=depth to the top of the reservoir, and
R=radius of the reservoir.

Based on hydraulic fracture extents reported from microseismic (Fisher et al., 2004), a reasonable radius for the reservoir would be R=2000 ft. Based on the Officer's Club #1 well, the depth to the top of the Barnett Shale is 5400 ft, giving a value of η=2.7. Using the predicted compaction of 0.18 ft, a Poisson' ratio of 0.15 (Table A.1), equation B.2 results in a predicted maximum subsidence at the surface of u_z=0.019 ft, or u_z=0.23 inches. This subsidence would be expected to decay very slowly away from the center of the depleted area, so differential settlement effects would be expected to be minimal as well.

Appendix C. Analytical Assessment of Fault Stability

Theory of Fault Stability and Derivation of Equations

The main emphasis of the derivations and calculations below is to assess whether production from the Barnett Shale will move faults into a state such that they are more or less likely to slip. This analysis is a qualitative assessment of the potential for slip on pre-existing faults in the Fort Worth Basin. The reason to state this as a qualitative assessment, even though the equations are quantitative, is because of uncertainty in the input data, particularly with regard to fault geometry and conditions and in situ stress magnitudes. There is also some uncertainty with regard to our understanding of the physical processes. As stated by Davis and Pennington (1989), although they computed that faults should slip in response to documented injection in many areas in Texas, they found in most cases there was no measurable seismicity. They concluded that there was instead aseismic slip in response to the driving stresses coming from injection, but the mechanisms were speculative.

Zoback and Healy (1984) and Barton and Zoback (1995) discuss the conditions under which pre-existing faults in the earth's crust will be critically stressed or poised for slip. Based on the Coulomb shear failure criterion, intact, unfractured rock, shear failure should fail when the principal stress state meets the following criterion (Zoback and Healy, 1984),

$$\sigma_1' \geq \left(\sqrt{\mu^2+1}+\mu\right)^2 \sigma_3' + \frac{2c}{\sqrt{\mu^2+1}-\mu}, \qquad \text{(C.1)}$$

where μ is the coefficient of friction, c is the cohesion, σ_1' is the maximum effective compressive stress (the vertical stress for normal faulting) and σ_3' is the minimum effective compressive stress (the minimum horizontal stress for normal faulting). Effective stress with respect to the shear failure criterion is defined as

$$\sigma' \equiv \sigma - P, \qquad \text{(C.2)}$$

where σ is the total stress and P is the pore (reservoir) pressure.

If we assume pre-existing, favorably oriented faults (such as the NE-SW faults shown in Figures 4 and 5), the cohesion can be assumed to be zero. We can then define a fault slip function, Φ, for a normal faulting stress regime as

$$\Phi = \sigma_{vert}' - \left(\sqrt{\mu^2+1}+\mu\right)^2 \sigma_{h\min}'. \qquad \text{(C.3)}$$

If $\Phi \geq 0$, fault slip is theoretically expected to occur. Thus, knowing the principal stresses, we can assess whether a fault is going to slip based on the Coulomb frictional sliding criterion. This does not, however, indicated anything about the magnitude of the slip or associated seismicity.

Because of our uncertainty of the initial state in the vicinity of Comanche Peak, we thought it best to evaluate whether changes caused by man-induced processes would make faults more or less likely to slip. A positive change would push faults toward slip, and a negative change would increase fault stability.

If the man-induced change we are evaluating is pore pressure change from gas production or water injection, we can evaluate the change in the components of C.3 as

$$\Delta\sigma_{vert}' = \Delta(\sigma_{vert} - P) = \Delta\sigma_{vert} - \Delta P, \text{ and} \qquad \text{(C.4)}$$

$$\Delta\sigma_{h\min}' = \Delta(\sigma_{h\min} - P) = \Delta\sigma_{h\min} - \Delta P. \qquad \text{(C.5)}$$

C.3 can then be rewritten to reflect only the change in susceptibility to slip as a result of pore pressure change, giving

$$\Delta\Phi = (\Delta\sigma_{vert} - \Delta P) - \left(\sqrt{\mu^2+1}+\mu\right)^2 (\Delta\sigma_{h\min} - \Delta P). \qquad \text{(C.6)}$$

The change in effective stress, which defines the strength of the fault, is given by ΔP. A reduction in pore pressure (ΔP<0) will increase the resistance to slip. The poroelastic change in the total stresses ($\Delta\sigma_{vert}$ and $\Delta\sigma_{hmin}$) modifies the shear stress resolved on the fault, because the shear stress is proportional to the difference in the extreme principal stresses (σ_{vert}-σ_{hmin} in the case of normal faulting). During depletion, the reservoir will shrink in size due to the poroelastic effect, and this induces a small tensile change in the total horizontal stress. The vertical stress is not changed appreciably because the weight of the overburden is unaffected by strains in the reservoir. Consequently, if the total vertical stress stays constant and the total horizontal stress decreases, the differential stress will increase, (σ_{vert}-σ_{hmin}), increasing the shear stress resolved on the fault and making slip more likely. The question remains, then, as to whether this increase in shear stress will be offset by the increase in effective stress (and frictional resistance) caused by pore pressure reduction.

Segall and Fitzgerald (1998) describe analytically how the poroelastic stress change can be calculated for a finite elliptical reservoir in an elastic half-space. The magnitude of the poroelastic stress change is primarily controlled by the shape of the reservoir and the elastic constants, in particular Biot's poroelastic constant, α_p. The poroelastic stress change as a result of oil and gas production has been observed in the field. Teufel et al. (1991) documented that for every unit change in reservoir pressure in Ekofisk field in the North Sea, the total minimum horizontal stress changed 0.8 units, or $\Delta\sigma_h / \Delta P \cong 0.8$. Salz (1977) documented a similar effect in the McAllen Ranch, Texas, field, with $\Delta\sigma_h / \Delta P \cong 0.5$. This means that not only are effective stresses influenced by changes in pore pressure in porous rocks, but that the magnitude of the total stress will also change, changing the shear stress resolved on pre-existing faults.

To compute the poroelastic change in horizontal stress, we make the simplification that the reservoir is laterally infinite, which is the pessimistic case. This results in the simple expression (Segall and Fitzgerald, 1998)

$$\Delta\sigma_{h\min} = \alpha_p \frac{(1-2\nu)}{(1-\nu)} \Delta P \text{, or} \tag{C.7}$$

$$\Delta\sigma_{h\min} / \Delta P = \alpha_p \frac{(1-2\nu)}{(1-\nu)} . \tag{C.8}$$

It is evident that the key parameters in evaluating poroelastic results for this simple case are Biot's poroelastic constant and Poisson' ratio. Using the average values for these properties indicative of the Barnett Shale (Table A.1), the poroelastic stress change ratio is expected to be $\Delta\sigma_h / \Delta P \cong 0.5$, similar to the number reported by Salz (1977) for the McAllen Ranch field.

Finally, incorporating the poroelastic stress change of C.7 into the fault slip criterion of C.6, and assuming there is no change in the vertical stress due to pore pressure change ($\Delta\sigma_{vert} \cong 0$), we can write an equation that describes the change in fault slip potential as a function of pore pressure change and elastic constants as

$$\Delta\Phi = \left[\left(\sqrt{\mu^2+1} + \mu \right)^2 \left(\frac{1-\nu-\alpha(1-2\nu)}{(1-\nu)} \right) - 1 \right] \Delta P . \tag{C.9}$$

If ΔΦ>0, fault slip is made more likely by pore pressure change, and if ΔΦ<0, fault slip is less likely. Since ΔP is negative for pore pressure reduction, the expression in the brackets (for convenience named here the "Coulomb factor") must also be negative to cause an increase in the likelihood of fault slip. Conversely, for injection ΔP is positive, so the Coulomb factor would need to be positive to make slip more likely under injection.

Application to Barnett Gas Production

The Coulomb factor is plotted in Figure C.1 for a range of Poisson's ratio and Biot's poroelastic constant, assuming a lower bound friction co-efficient of μ=0.6 for typical crustal rocks (Zoback and Healy, 1984). Based on the data from Table A.1 (ν=0.15, α_p=0.65), the most likely value of the Coulomb factor for the Barnett is +0.45. This means that pore pressure reduction in the Barnett Shale is likely to make faults within the reservoir section *less likely* to slip. This conclusion is consistent with those of Segall and Fitzgerald (1998) , where they found that Biot's poroelastic constant had to be higher than a certain threshold value in order to expect pore pressure reduction to cause fault slip. Our analysis shows that the Barnett's poroelastic constant would need to be greater than 0.8 for pore pressure reduction to increase the likelihood of fault slip.

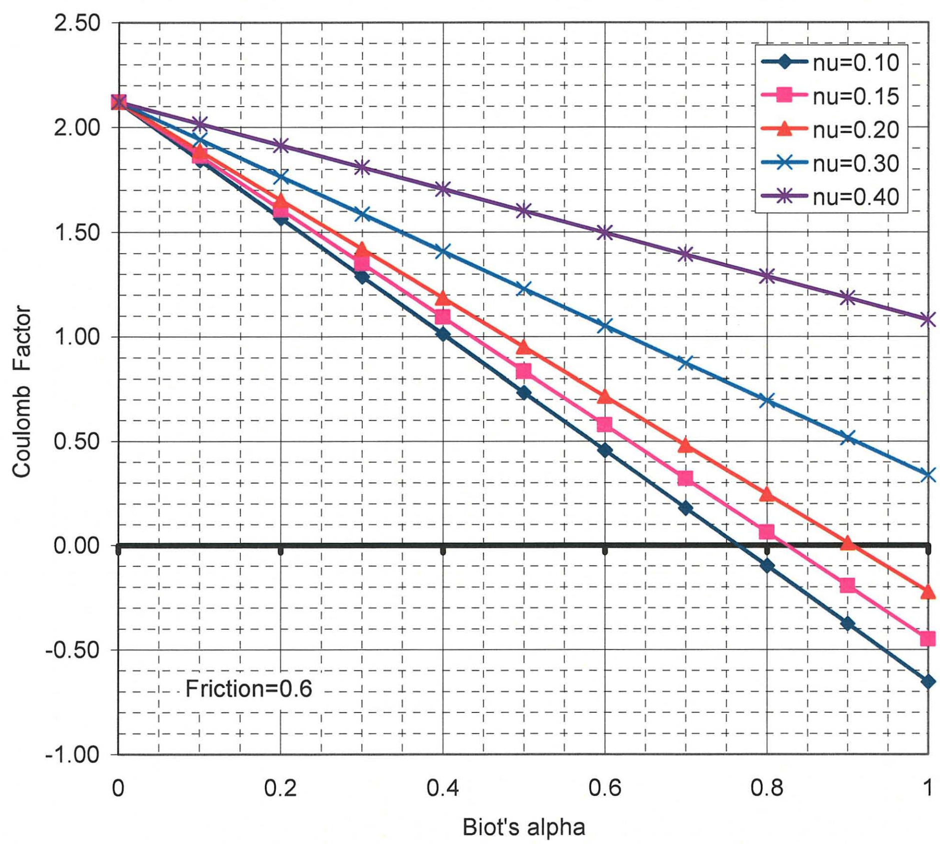


Figure C.1. Coulomb factor as a function of Poisson's ratio and Biot's poroelastic constant.

Application to Ellenberger Water Injection

Using the mechanical properties of the Ellenberger from Appendix A, the likely Coulomb factor would be +1.7 (using log values of ν=0.3, α_p=0.25). A positive value means, again, that faulting would become less like during pore pressure reduction, but under injection, pore pressure increase would make fault slip more likely.

What is the Current State of Fault Stability?

It was stated earlier that this analysis will focus on the change in fault stability because the initial values for in situ stresses, fault geometry and condition, etc., had a fair degree of uncertainty. However, our data does allow an estimate of the present state of fault stability in the Comanche Peak area, based on the log data of Appendix A. Using equation C.3, the present slip state of faults can be assessed. If the value of the Coulomb Failure stress, Φ, is greater than 0, the theory predicts that favorably oriented faults should slip. If the value is less than 0, then the faults should be stable. The accuracy of this assessment depends strongly on the validity of the equations and models inherent in calculating mechanical properties and in situ stress from the log, the accuracy of input parameters such as pore pressure and density (which was estimated constant over the entire interval), and the presumption that slip is governed by a Coulomb frictional shear criterion (Zoback and Healy, 1984).

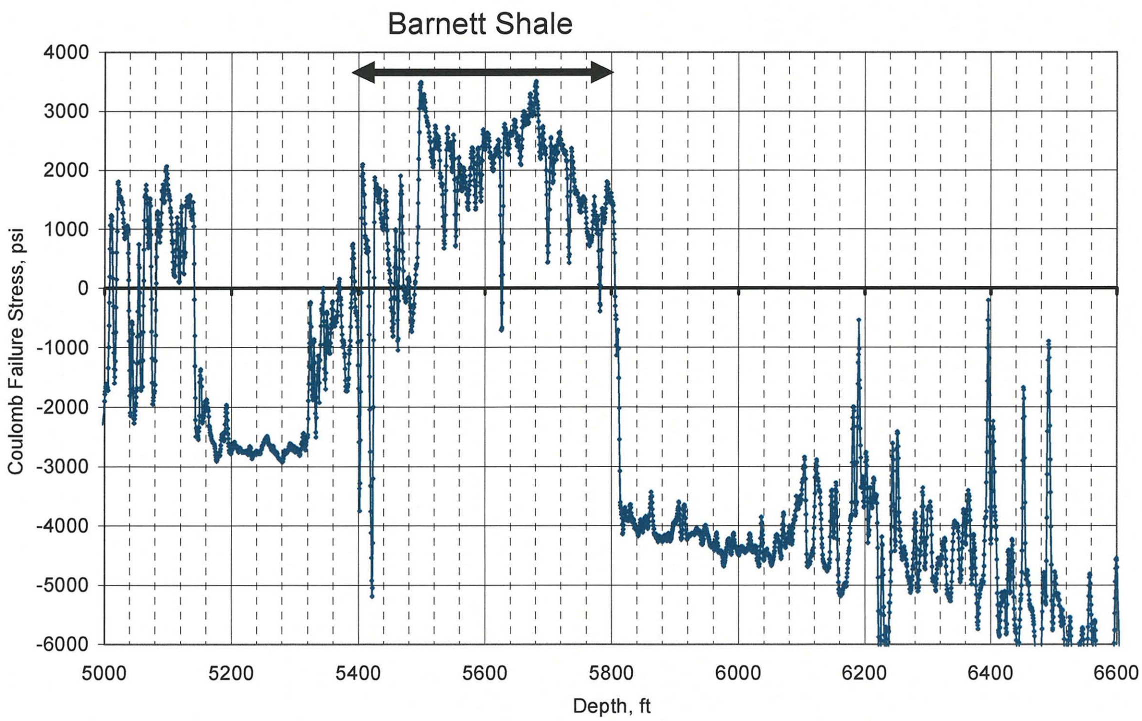


Figure C.2. Evaluation of present state of fault stability from the Officer's Club #1 well. Values of Coulomb Failure stress greater than 1 indicate likely slip or shear failure on favorably oriented faults.

The results in Figure C.2 suggest that the Barnett Shale should presently be in a fairly unstable condition with respect to fault slip, considering the Coulomb failure stress is greater than zero. It must be emphasized that this implies slip only on pre-existing faults that are favorably oriented (dip about 60 degrees and strike perpendicular to the minimum horizontal stress) and have no fault plane cohesion (cohesion has been assumed to be zero). Pre-existing faults that are not favorably oriented or that have some cohesion due to cementation are not predicted to slip, nor is intact rock predicted to spontaneously fail. In addition, the analysis of the impact of pore pressure reduction states that ongoing gas production will reduce the likelihood of faults to fail in the future within the reservoir section. Is Figure C.2 consistent with observation in the Barnett Shale? Perhaps, considering that hydraulic fracturing operations, which only locally increase pore pressure, cause a wide distribution of very low magnitude seismicity. If the Barnett were at an initial state that was very stable to fault slip, it seems unlikely there would be as much microseismic activity. The low magnitude of the Barnett seismicity induced by hydraulic fracturing could be attributed to the localized nature of the stress and pressure changes and the limited size of pre-existing fractures in the formation, or at least the limited size of pre-existing fault segments that slip.

In assessing the Ellenberger Limestone, it plots significantly below zero, indicating fault stability. The Barnett had a positive Coulomb Failure stress of 2000 psi, and is evidently only experiencing microseismicity due to hydraulic fracture injections. The Ellenberger Limestone plots at -4000 psi or less, suggesting it would take a very large stress change or pore pressure change to induce seismicity in this formation. This argues for low seismic hazard risk due to fluid injection in the Ellenberger in the future.