EPA Hydraulic Fracturing Workshop
March 10th - 11th, 2011

NATURAL GAS: FUELING AMERICA'S FUTURE

"Fracture Design in Horizontal Shale Wells – Data Gathering to Implementation"

Tim Beard

Sr. Engineering Advisor - Completions

Chesapeake Energy Corporation

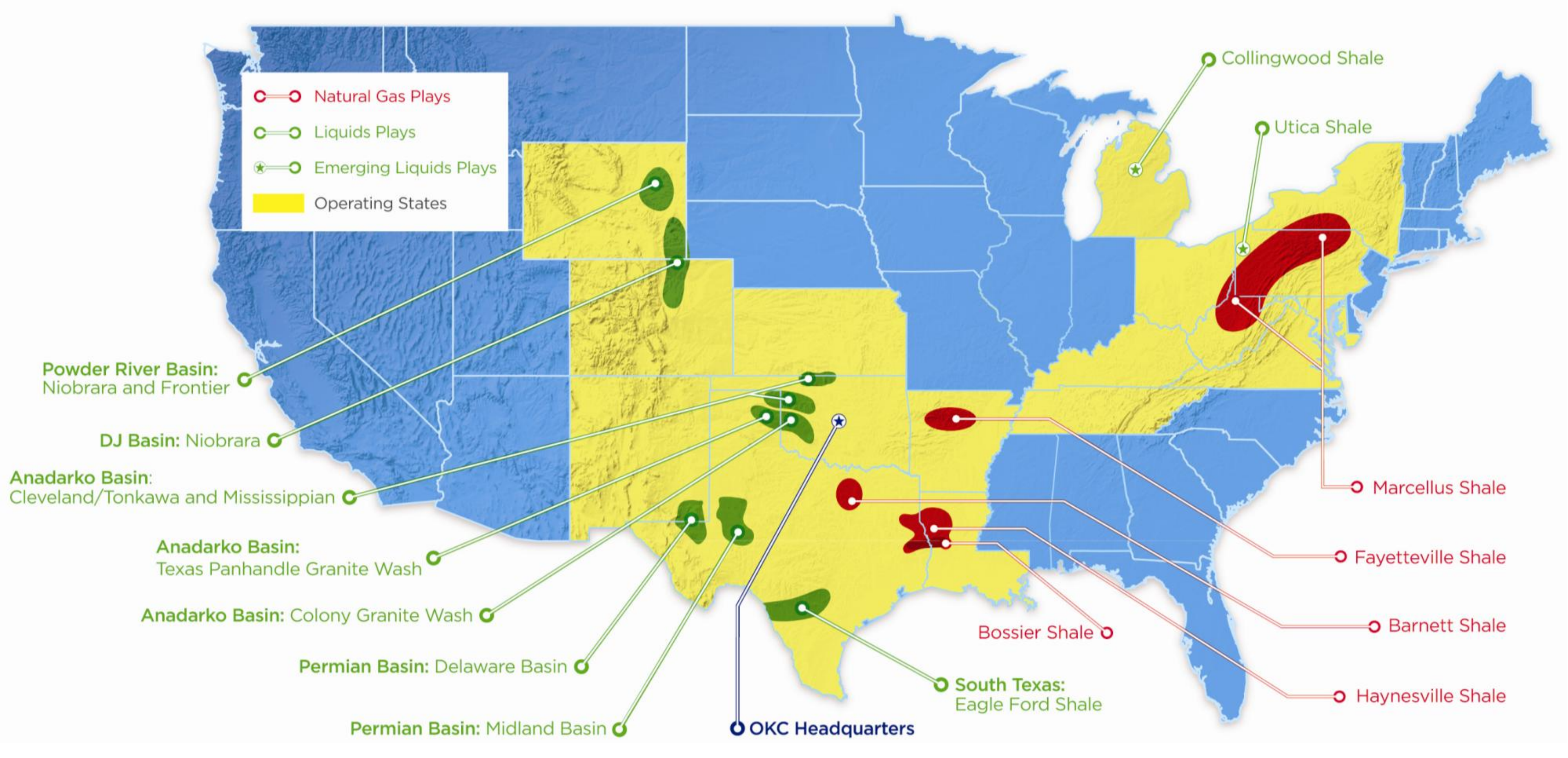
6100 N. Western Avenue | Oklahoma City, OK 76118 | 405-935-8000

AskChesapeake@chk.com | chk.com | NYSE: CHK

Presentation Overview

- Goal
- Planning
  - Data
    - Measuring
    - Validating
  - Properties Needed in Modeling
  - Designing the Hydraulic Fracture
  - Frac Models in Vertically Heterogeneous Formations
- Execution

CHK's Operating Areas



Low-risk, U.S. onshore asset base; Not exposed to economic, geopolitical or technological risks internationally or in the Gulf of Mexico

Shale Information

Shale Play	Fayetteville	Barnett	Eagle Ford	Haynesville	Marcellus
Average Depth From Surface (ft)	4,500	7,400	9,000	11,500	7,100
Bottom Hole Temperature (F)	130	190	260	320	145
Bottom Hole Pressure (psi)	2,000	2,900	6,200	10,000	4,600

What is the Goal of Hydraulic Fracturing?

- **Maximize the Stimulated Reservoir Volume (SRV) along the horizontal wellbore for a given well spacing to maximize hydrocarbon production within the zone of interest.**
  - Orientation and lateral length
  - Vertical placement within flow unit
  - Rock Properties/Mechanics
  - Stages/Perf Clusters/Isolation
  - Fluid and proppant selection

Planning

What data do we use?

What are the main variables that need to be factored into each frac design?

- Porosity and Permeability
- Lateral Length
- Brittleness vs. Ductility
    - Young's Modulus
    - Poisson's Ratio
    - Fracture Toughness
- Thickness
- Barriers
- Depth
- In-Situ Stress
- Maximum Principle Stress Direction
- Lithology of Pay
- Stress Anisotropy
- Natural Fractures
- Gas or Liquids Reservoir
- Temperature
- Reservoir Pressure

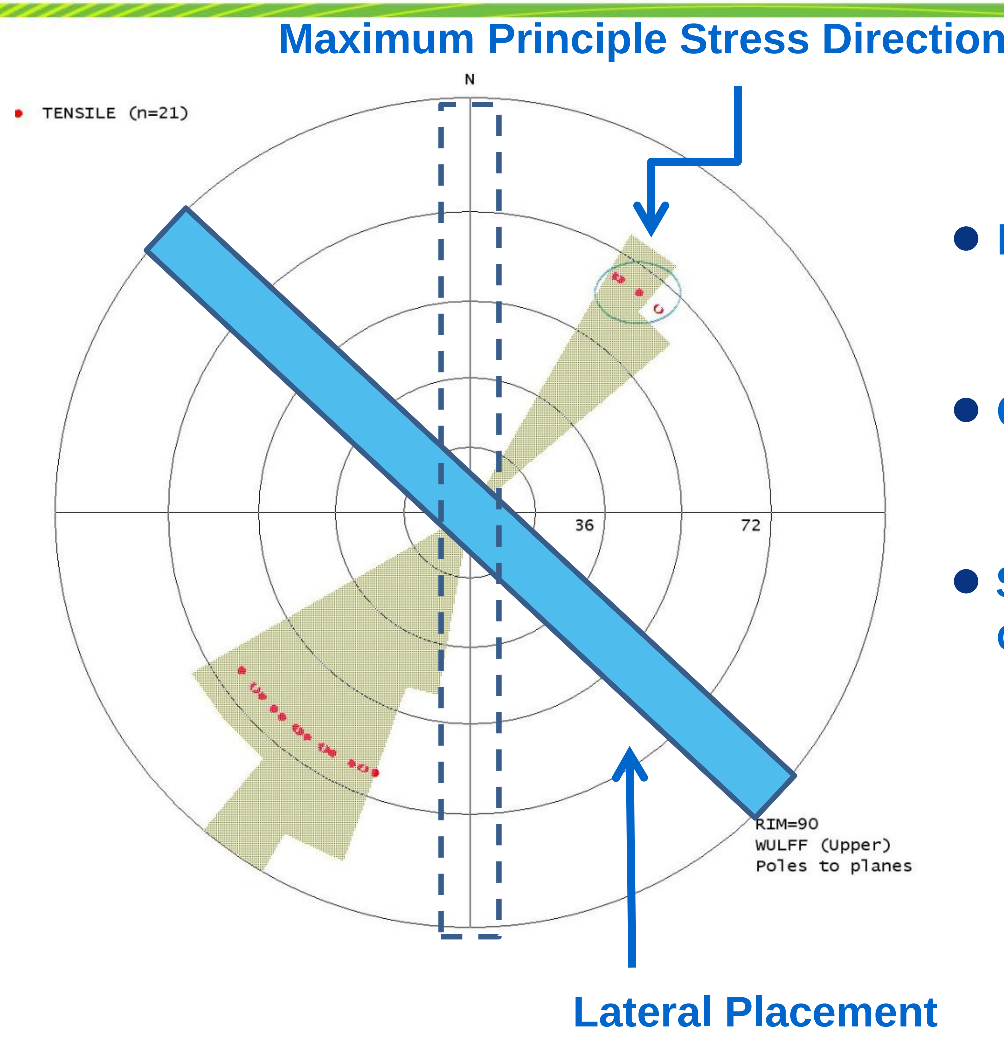
Wireline Log Data

- **Logs are run in regionally representative pilot wells over the zone(s) of interest.**
  - Triple Combo Log, Spectral Gamma Ray, Dipole Sonic Log, Formation MicroImager

- **The data gathered from the logs is utilized to do a petrophysical analysis and to calculate the rock mechanical properties of the reservoir to determine pay intervals, barriers, etc.**

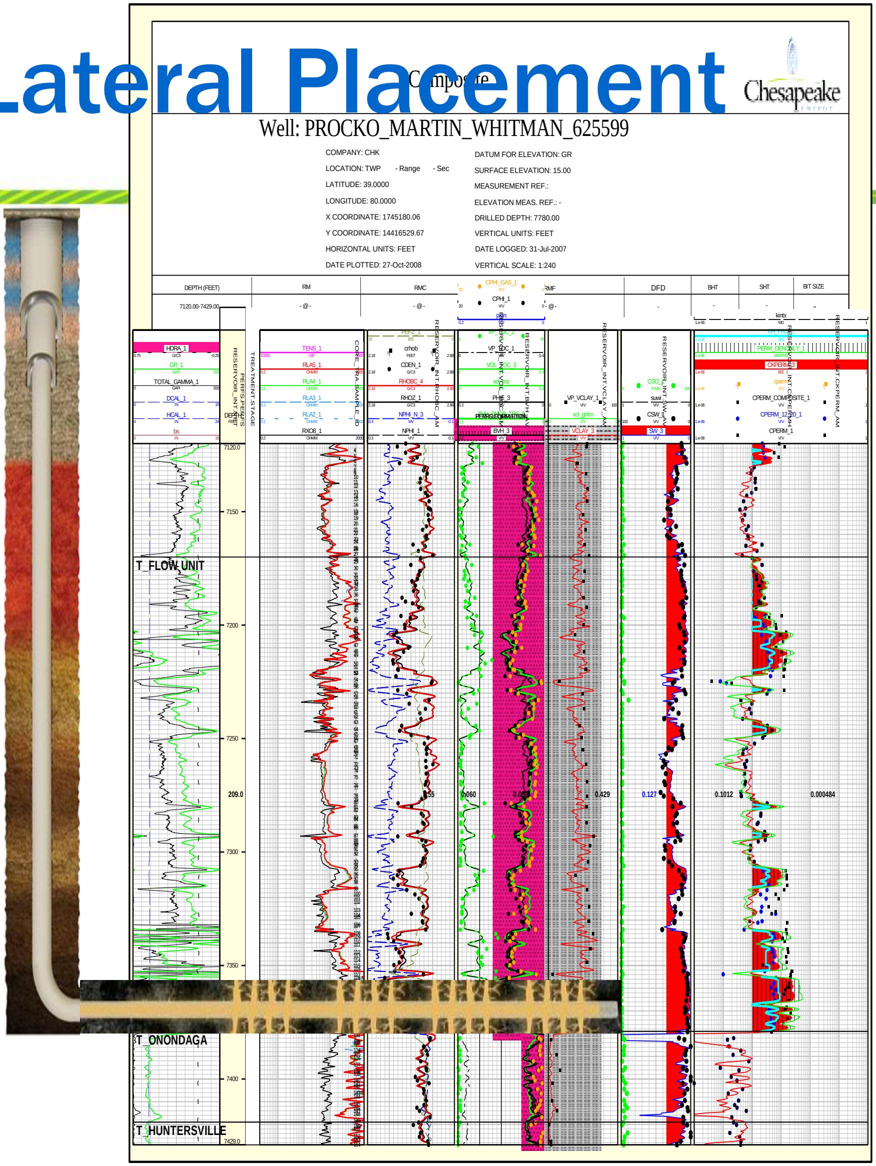
- **FMI and multi-caliper log data are also used to determine a maximum and minimum principle stress direction and to determine if there are natural fractures present.**

Lateral Orientation



- Perpendicular to maximum principle stress
- Optimize transverse fracturing
- Slight variations for more efficient pattern development

Lateral Placement



- Target highest quality rock with consideration given to stress profile and fracture geometries
- Preferred lateral placement in upper to middle portion of target zone to optimize proppant placement
- Toe high with option of traversing the entire section

Mechanical Properties and Stress Estimation from Acoustic Logs

- **Elastic Moduli Estimated from Acoustic Logs**
- **Several Stress Equations are Appropriate**
  - Uniaxial Transverse Isotropic Equation (Lateral Strain Model):

    $$\sigma_{Hmin} = (E_h/E_v)(v_v/(1-v_h))(\sigma_v-\alpha Pp) + \alpha Pp + (E_h/(1-v_h^2))\varepsilon_{hmin} + (E_h v_h/(1-v_h^2))\varepsilon_{hmax}$$

  - This equation expands the $\sigma_{tectonic}$ to incorporate lateral strain. Tectonic strain creates greater stress in stiff sandstone/limestone beds and less stress in organic-rich shales.
  - Estimated Stress Calibrated with Well Test

Pump-In Testing: Key Calibration

- **Pump-In Tests**
  - Conventional Pump-In Tests in Cased Hole
    - Closure Stress is Determined
    - After Closure Analysis
  - MDT Pump-In Tests in Open Hole
    - Closure Stress is Determined
- **Core Data**
- **The pump-in tests along with the core data calibrate mechanical properties data.**

Fracture Model – Mechanical Properties

- **Petrophysics processes the Dipole Sonic log for rock mechanical properties and that data is utilized in the frac model.**

Zone Name	TVD at Bottom (ft)	MD at Bottom (ft)	Stress Gradient (psi/ft)	Stress (psi)	Young's Modulus (psi)	Poisson's Ratio	Fracture Toughness (psi-in^½)
Shale	6175.73	-	0.875161	5404.76	4.3915e+06	0.295776	1500
Shale	6176.24	-	0.846423	5227.71	4.4124e+06	0.28605	1500
Transition	6179.16	-	0.865969	5350.96	4.5793e+06	0.293178	1200
Transition	6179.59	-	0.901429	5570.47	4.7576e+06	0.308763	1200
Transition	6180.71	-	0.836328	5169.1	4.7082e+06	0.279375	1200
Shale	6181.25	-	0.860382	5318.23	4.5645e+06	0.289449	1500
Shale	6181.69	-	0.880481	5442.86	4.4466e+06	0.297198	1500
Shale	6182.6	-	0.858929	5310.42	4.3654e+06	0.286416	1500
Shale	6183.64	-	0.822133	5083.77	4.2728e+06	0.268311	1500
Shale	6187.7	-	0.853061	5278.48	4.3784e+06	0.28404	1500
Transition	6188.59	-	0.88228	5460.06	4.4926e+06	0.298361	1200
Shale	6190.1	-	0.850508	5264.73	4.4179e+06	0.28334	1500
Shale	6190.67	-	0.816871	5056.98	4.3811e+06	0.266507	1500
Shale	6191.53	-	0.798963	4946.8	4.3362e+06	0.257548	1500
Shale	6192.09	-	0.862908	5343.21	4.3477e+06	0.287507	1500
Shale	6194.59	-	0.842594	5219.52	4.402e+06	0.278496	1500
Shale	6195.64	-	0.823902	5104.6	4.4738e+06	0.272302	1500
Shale	6197.74	-	0.836395	5183.76	4.3808e+06	0.276541	1500
Shale	6200.72	-	0.820347	5086.74	4.3991e+06	0.270034	1500
Shale	6201.16	-	0.842943	5227.22	4.4382e+06	0.280273	1500
Transition	6202.09	-	0.827577	5132.71	4.5017e+06	0.272377	1200
Transition	6202.68	-	0.847701	5258.02	4.7584e+06	0.286706	1200

Fracture Model – Fluid Flow and Leakoff

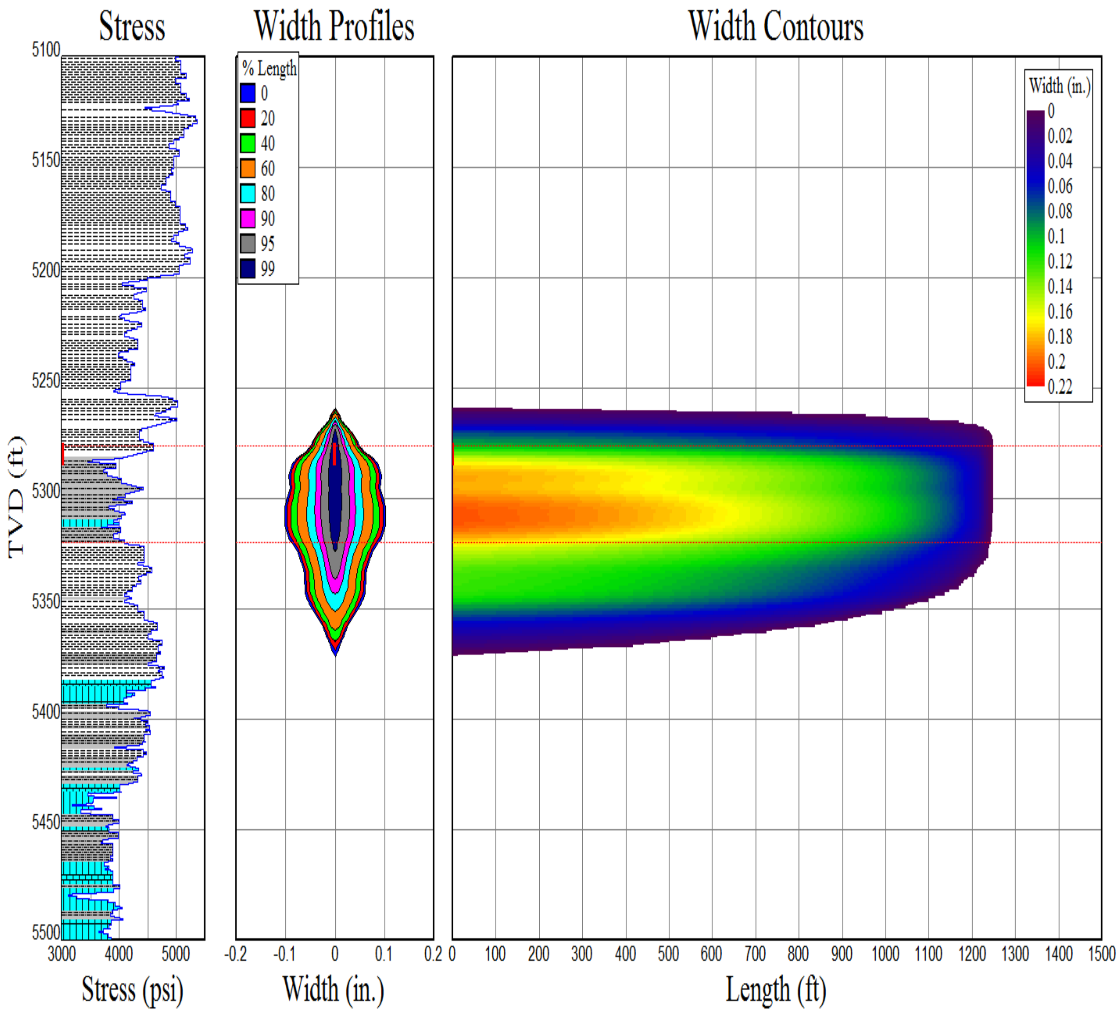
- **The fluid loss data input into the model.**

Zone Name	TVD at Bottom (ft)	MD at Bottom (ft)	Reservoir Pressure Gradient (psi/ft)	Reservoir Pressure (psi)	**Total Compres. (1/psi)**	Permeability (mD)	Porosity (fraction)	Fluid Visc. Reservoir (cp)	FR01 Fluid Visc. Filtrate (cp)	FR01 Cw (ft/min^½)
Shale	6175.73	-	0.600002	3705.45	0.00015608	0.001	0.07	0.02	10	10
Shale	6176.24	-	0.599983	3705.64	0.00015605	0.001	0.07	0.02	10	10
Transition	6179.16	-	0.599955	3707.22	0.00015604	0.005	0.08	0.02	10	10
Transition	6179.59	-	0.600009	3707.81	0.00015603	0.005	0.08	0.02	10	10
Transition	6180.71	-	0.599976	3708.27	0.00015602	0.005	0.08	0.02	10	10
Shale	6181.25	-	0.600041	3709	0.00015602	0.001	0.07	0.02	10	10
Shale	6181.69	-	0.599963	3708.78	0.000156	0.001	0.07	0.02	10	10
Shale	6182.6	-	0.600017	3709.67	0.00015599	0.001	0.07	0.02	10	10
Shale	6183.64	-	0.599994	3710.15	0.00015598	0.001	0.07	0.02	10	10
Shale	6187.7	-	0.599959	3712.37	0.00015595	0.001	0.07	0.02	10	10
Transition	6188.59	-	0.600036	3713.38	0.00015594	0.005	0.08	0.02	10	10
Shale	6190.1	-	0.6	3714.06	0.00015591	0.001	0.07	0.02	10	10
Shale	6190.67	-	0.600032	3714.6	0.00015589	0.001	0.07	0.02	10	10
Shale	6191.53	-	0.600019	3715.04	0.00015586	0.001	0.07	0.02	10	10
Shale	6192.09	-	0.600022	3715.39	0.00015584	0.001	0.07	0.02	10	10
Shale	6194.59	-	0.599964	3716.53	0.0001558	0.001	0.07	0.02	10	10
Shale	6195.64	-	0.600028	3717.56	0.00015577	0.001	0.07	0.02	10	10
Shale	6197.74	-	0.599972	3718.47	0.00015576	0.001	0.07	0.02	10	10
Shale	6200.72	-	0.600037	3720.66	0.00015575	0.001	0.07	0.02	10	10
Shale	6201.16	-	0.599998	3720.68	0.00015574	0.001	0.07	0.02	10	10
Transition	6202.09	-	0.600006	3721.29	0.00015569	0.005	0.08	0.02	10	10
Transition	6202.68	-	0.599989	3721.54	0.00015569	0.005	0.08	0.02	10	10

Fracture Model Methodology

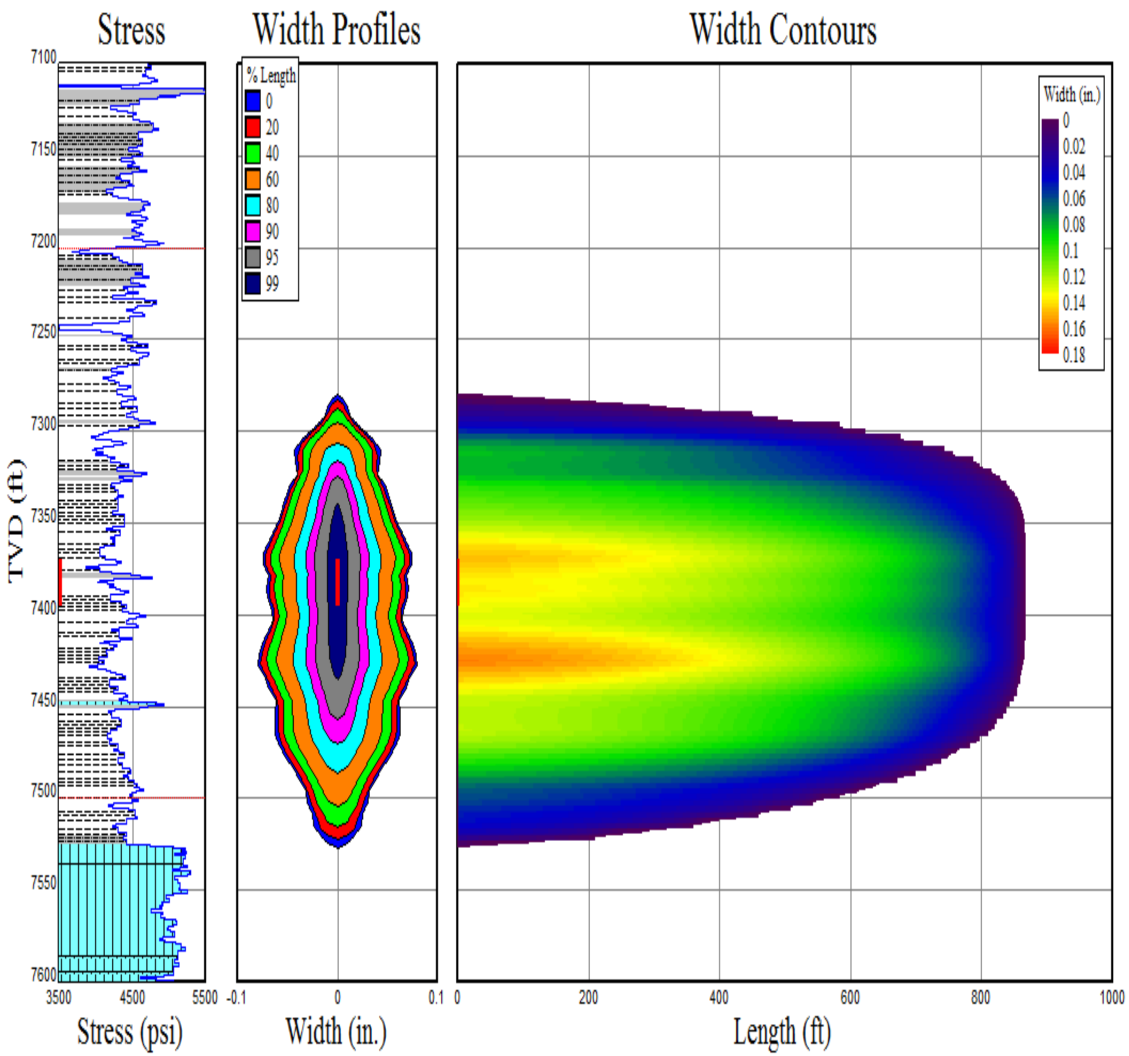
- The actual deviation survey for the well that is being modeled, as well as the planned perforations for the well, are entered.
- A pump schedule is entered into the fracture model.
- Numerous iterations with different pump schedules, perforation schemes, and other variable modifications are run to “optimize” the design.
- What is the play specific “optimum” design?
  - Covers the height of the pay interval
  - Creates a sufficiently conductive propped fracture length that fits our well and perf spacing, with some overlap.
  - Minimizes well interference.
  - Provides the best production results based on reservoir flow simulation.

Example Frac Model Results



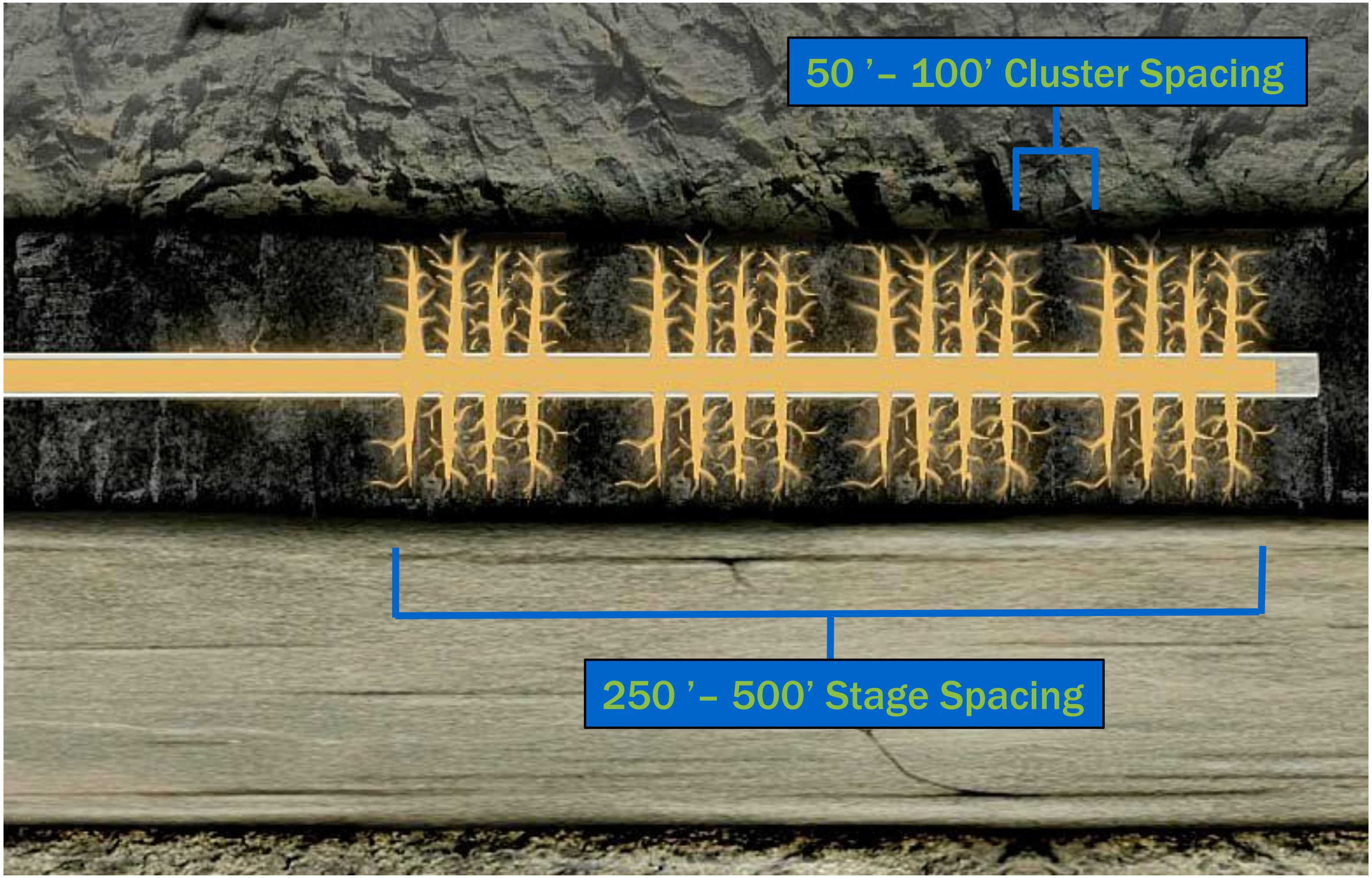
- **As depicted in the model, the fracture propogates primarily only in the lower stress portion of the rock.**
  - The lower stress portion of the reservoir "contains" the frac
- **High stress barriers exist above and below the fracture matching lithology changes.**
- **Vertical variations in stress exist throughout the sections depicted.**

Example Frac Model Results



- Fracture is contained by lower stress interval and high stress barriers above and below the lower stress interval.
- Variable stress throughout section, matching lithology changes
- Greater height growth typically leads to less fracture length.
  - Note, this is predicted fluid distribution, not predicted propped fracture length.

Perforation Clusters and Stage Spacing



Not To Scale

Fluid Selection

- Utilize core data and lab fluid-rock sensitivity testing to determine fluid additives
- Maximize slickwater volumes vs. gelled fluid volumes
- Utilize light gels/crosslink to place higher sand concentrations where necessary in gas shales
- In liquids rich plays, more gels or crosslinked gels are utilized to promote greater conductivity in the propped fractures
- Reservoir modeling suggests higher primary fracture conductivity required to improve well performance
- CHK Promotes development and leads in the use of “greener”, more environmentally friendly hydraulic fracturing additives

Green Frac Status – Chemical Additives

Additive	Barnett	Fayetteville	Haynesville	Marcellus	Eagle Ford
Friction Reducer	GF* Test	GF Test	GF Test	GF Test	GF Test
Biocide	GF Test	GF Test	GF Test	GF Test	GF Test
KCl Substitute	Eliminated	GF Substitute	GF Substitute	Eliminated	GF Substitute
Scale Inhibitor	GF Test	GF Test	X	X	
Surfactant	Eliminated	Eliminated	Eliminated	Eliminated	X
Gel	X		X	Occasional	X
Cross-linker			X		X
Breaker	X		X	Occasional	X
HCl	X	X	X	X	X

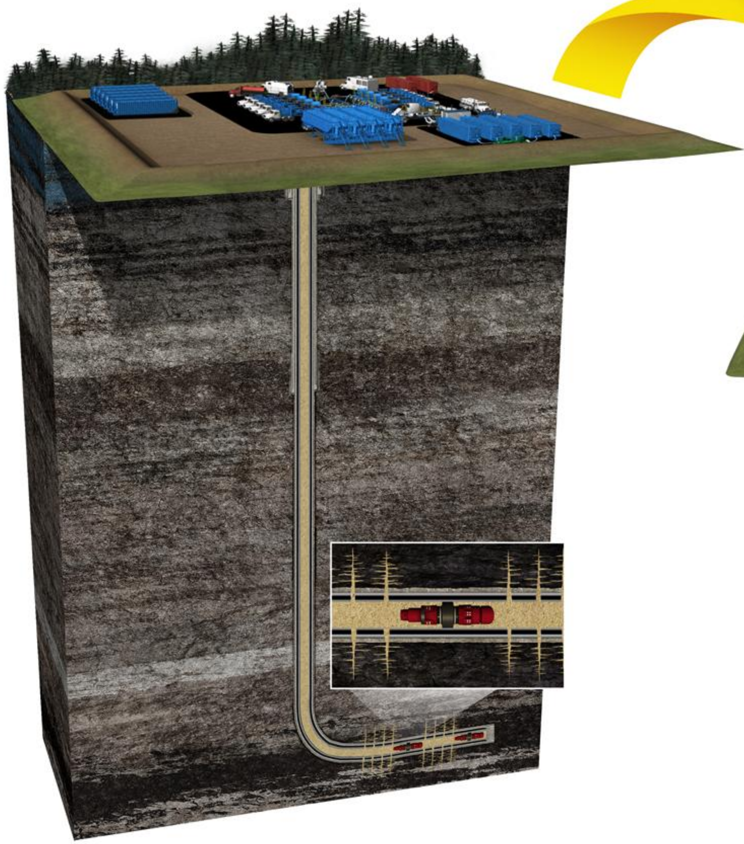
* - Green Frac™

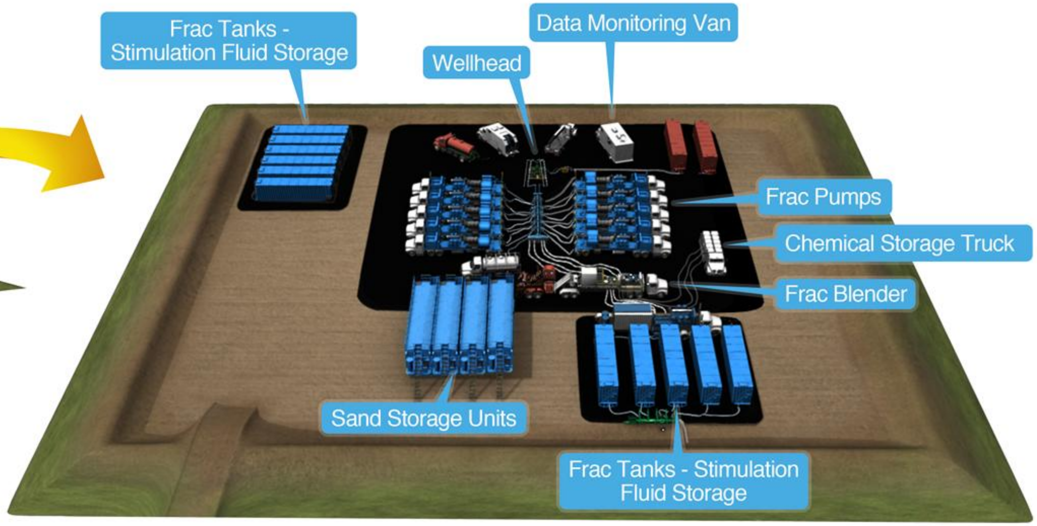
Proppant Selection

- 100 mesh sand is typically used in the early portion of the job for enhanced distance and height, diversion, etching, and as a propping agent
- 40/70 and 40/80 mesh proppants are currently the predominant proppants used in gas shales
- 30/50 and 20/40 proppant used in some areas for fracture conductivity enhancement (especially important in the liquids rich plays)
- Resin Coated Tail-Ins - used where sand flowback is an issue or where more proppant strength and conductivity are needed
- Ceramic Proppants are utilized where higher conductivity and higher strength are required
- Increased proppant volumes and less fluid addresses conductivity and environmental issues


Execution

Hydraulically Fracturing the Shale

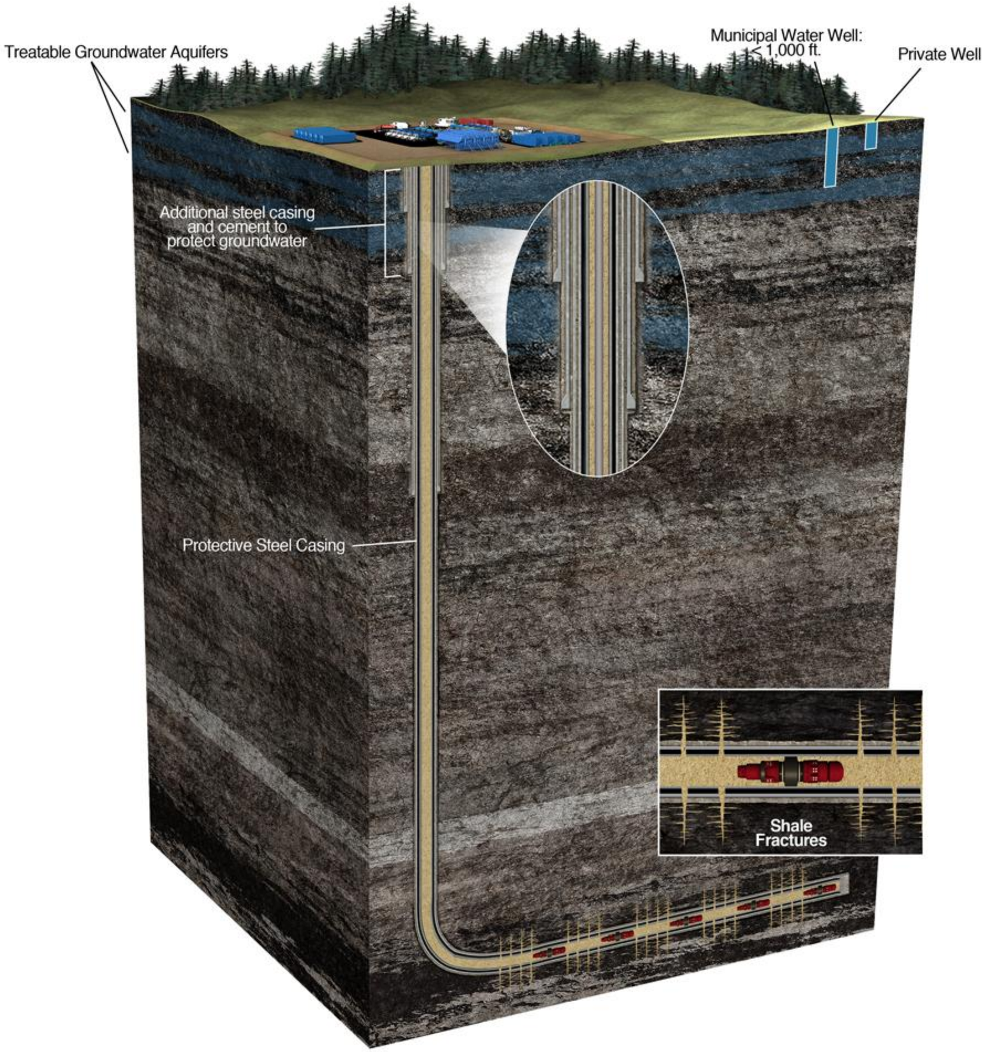




Typical Hydraulic Fracturing Job:

- 10-20 Pumps
- 2-4 Sand Storage Units
- Blender
- Hydration Unit
- Frac Tanks
- Chemical Storage Truck
- Data Monitoring Van
- 20-30 Workers

Hydraulically Fracturing the Shale



- 6 layers of protection between the wellbore and groundwater aquifers during hydraulic fracturing operations.
- Horizontal shale wells are hydraulically fractured at depths that typically exceed a mile beneath the groundwater.

Summary

- Planning and executing an “optimum” hydraulic fracture requires a multidisciplinary approach of gathering data, confirming data, modeling the optimum fracture and well performance, and executing a plan based on those models.
- Hydraulic Fracture models do a good job of depicting and/or predicting vertical barriers and thus fracture growth.
  - This data has been, and continues to be, confirmed in multiple ways.
    - Microseismic
    - Lab Tests
    - Core Data

Summary

- Extensive data collection results in hydraulic fracturing jobs that are designed to remain in the proper formation
- Remaining in the zone of interest maximizes production and minimizes opportunities to negatively impact production
- Hydraulic fracturing is a highly engineered process that takes into account numerous variables.

Chesapeake ENERGY

Thank You – Questions?

Tim Beard

Sr. Engineering Advisor - Completions

Chesapeake Energy Corporation
6100 N. Western Avenue | Oklahoma City, OK 76118 | 405-935-8000
AskChesapeake@chk.com | chk.com | NYSE: CHK

Fracture Design in Horizontal Shale Wells – Data Gathering to Implementation

Tim Beard
Chesapeake Energy Corporation

Introduction

Hydraulic fracturing has been used in the petroleum industry since the late 1940s. However, the hydraulic fracturing of horizontal shale wells is a relatively new practice. Although relatively "new," the hydraulic fracturing of horizontal wells is still governed by the same physics as a conventional reservoir. The biggest differences between hydraulic fracturing operations in a more conventional and shale reservoir are the type of fluids utilized and the volume of fluid and sand pumped. The increase in fluid and sand volume in shale wells is primarily due to the need to maximize stimulated reservoir volume (SRV) in the relatively low permeability formation.

The goal of hydraulically fracturing a typical shale play is to contact as much of the reservoir rock as possible with proppant-filled fractures. The total volume contained between all propped fractures along the wellbore represents the SRV. To maximize the SRV, there are many variables that must be considered prior to drilling a horizontal shale well.

This abstract will focus on general fracture design in horizontal shale plays across the U.S. with an emphasis on the data taken into consideration for each frac job and a brief discussion of how that data is obtained and used. Additional discussion will be focused on frac modeling and the validity of frac barriers. Finally, a brief discussion of the diagnostics used to determine frac placement will be included.

Planning to Hydraulically Fracture a Horizontal Shale Well

Prior to drilling, companies must gather local and regional in-situ stress data (usually by drilling a pilot hole and running logs), and make economic and land decisions concerning the orientation, length, and placement of the lateral prior to drilling a horizontal well. With the obtained stress data and reservoir properties, evaluation and design of the horizontal well and stimulation is performed comprising some of the key analyses and tasks briefly described below.

Orientation and Lateral Length

One of the first variables that is considered when drilling a horizontal shale well is the maximum and minimum principle stress orientation in the target formation. These data are typically estimated from wireline logs in a pilot hole. The maximum and minimum principle stress directions are typically consistent throughout a given geographic area. Therefore, a few pilot holes are all that are necessary to determine the principle stress directions for a given region within a play development area. Shale wells are typically drilled perpendicular to maximum principle stress (Figure 3). Drilling a well perpendicular to maximum principle stress provides an orientation where the hydraulically induced fractures can propagate normal to the wellbore during the hydraulic fracturing process. The fractures will propagate in the direction of maximum principle stress because they preferentially open against the minimum principle stress. Simply stated, horizontal shale wells are drilled to create the maximum amount of transverse fractures – thereby attempting to maximize production.

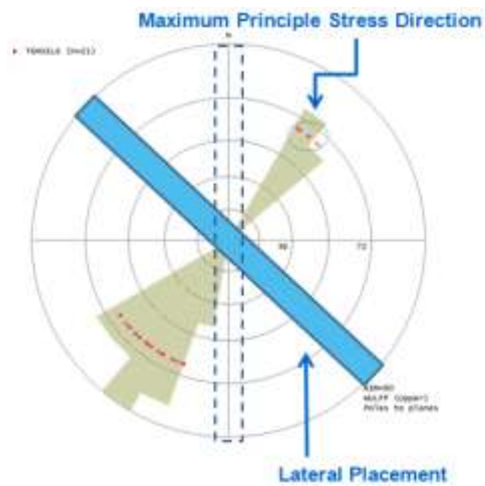


Figure 3

Lateral length is a variable that allows the operator the option of creating more (or less) transverse fractures. The longer the lateral, typically the greater the number of perforation clusters and the greater the number of hydraulic fracturing stages. However, maximum practical lateral length is limited by increasing potential production difficulties that are faced in longer laterals. Ultimately, lateral length is driven by economics associated with drilling costs, completion efficiency, wellbore failure risk, etc. Both lateral length and the azimuth in which the well is drilled are often affected by lease boundary considerations.

Horizontal Placement

Where the lateral portion of the wellbore is vertically positioned or “landed” is critical to optimum stimulation and fracture geometry, and resulting well production. There are numerous theories in the industry about where in the zone of interest the lateral should be horizontally drilled, but a common denominator is to target the highest quality rock with consideration given to the stress profile and predicted fracture geometries. Landing the lateral in the upper to middle portion of the targeted, preferred rock allows for the optimization of proppant placement in slickwater applications. From a production perspective, it is best to land the lateral slightly lower in section and drill at a slight incline through the formation, if the formation dip allows for this approach. This "toe up" drilling practice promotes less liquid hold-up or build-up across the lateral.

Data Gathering

Once the lateral is drilled, the planning of the actual hydraulic fracturing takes into account many variables obtained from data gathered in each wellbore (or in pilot holes) by logging, and in some cases, analysis of core samples. Some, but not all, of the variables that are involved in the fracture design include:

- Porosity and Permeability
- Brittleness vs. Ductility
    - Young's Modulus
    - Poisson's Ratio
- Thickness
- Barriers
- Depth
- In-Situ Stress
- Lithology
- Stress Anisotropy
- Natural Fractures
- Gas or Liquids Reservoir
- Temperature
- Reservoir Pressure

Young's Modulus and Poisson's ratio are typically calculated from the shear and compressional data estimated from dipole-sonic log response. These values are then used to calculate the in-situ stress of the rock using several possible stress equations. A stress equation that is applicable in many transverse isotropic shales plays is:

$$\sigma_{Hmin} = (E_h/E_v)(\nu_v/(1-\nu_h))(\sigma_v-\alpha Pp) + \alpha Pp + (E_h/(1-\nu_h^2))\varepsilon_{hmin} + (E_h\nu_h/(1-\nu_h^2))\varepsilon_{hmax}$$

Where:
σ_{Hmin} = Minimum Horizontal Stress
E_h = Horizontal Young's Modulus
E_v = Vertical Young's Modulus
ν_v = Vertical Poisson's Ratio
ν_h = Horizontal Poisson's Ratio
σ_v = Vertical Stress
α = Biot's Coefficient
Pp = Pore Pressure
ε_{hmin} = Minimum Horizontal Strain
ε_{hmax} = Maximum Horizontal Strain

This equation recognizes that shales are anisotropic. With lower v_h in organic rich shales and greater E_h, the difference in σ_{Hmin} between shale and sandstone/limestone decreases and often reverses. This leads to a minimum stress in shales and the bounding sandstone/limestone become barriers. The equation above has also replaced the $s_{tectonic}$ term that has been used in the past, to incorporate lateral strain $((E_h/(1-v_h^2))\varepsilon_{hmin} + (E_h v_h/(1-v_h^2))\varepsilon_{hmax})$. For stiff sandstone/limestone interbedded with slightly less stiff shale, the tectonic strain creates greater stress in the stiffer beds and less stress in the shales. This equation is the best fit for pump-in data in the field.

Data Verification and Calibration

Pump-in tests are done on regionally representative wells to obtain actual stress values and validate estimated stresses obtained from the above equation. A typical pump-in test is done by pumping into a well at a rate high enough to fracture the rock with a small volume of fluid, followed by a time period of hours to measure closure. This closure pressure provides the actual σ_{Hmin}. After-closure analysis can also be performed by observing a well post-closure to determine permeability, pore pressure, etc. Core data are also a valuable tool in elastic properties measurement and calibration of wireline-interpreted elastic moduli.

Fracture Modeling

Estimation of fracture geometry is modeled using an analytical fracture modeling simulator. Rock mechanical properties and fluid loss data (permeability, porosity, pressure, compressibility, fracturing fluid properties, etc.) are principal inputs into fracture modeling. After entering the directional survey of the wellbore, an iterative process of comparing and contrasting models using differing variables is performed with the goal of designing the "optimum" hydraulic fracture for the given set of reservoir properties. An "optimum" fracture design is one that:

1) Fractures the height of the pay interval
2) Creates a sufficiently conductive propped fracture half length that fits the well and perforation cluster spacing, with some overlap.
3) Minimizes well interference
4) Takes into consideration the numerous variables, and accounts for the role played by each parameter to achieve the largest SRV and ultimately the greatest production.

Fracture length and height are two primary outputs of fracture modeling software. The example model (Figure 4) below shows a fracture half length of ~1,200' and a fracture height of ~100'. As can be seen, the fracture is contained in a lower stress region of the overall stress column. Barriers exist above and below the primary zone of interest, confining the fracture to the lower stress interval.

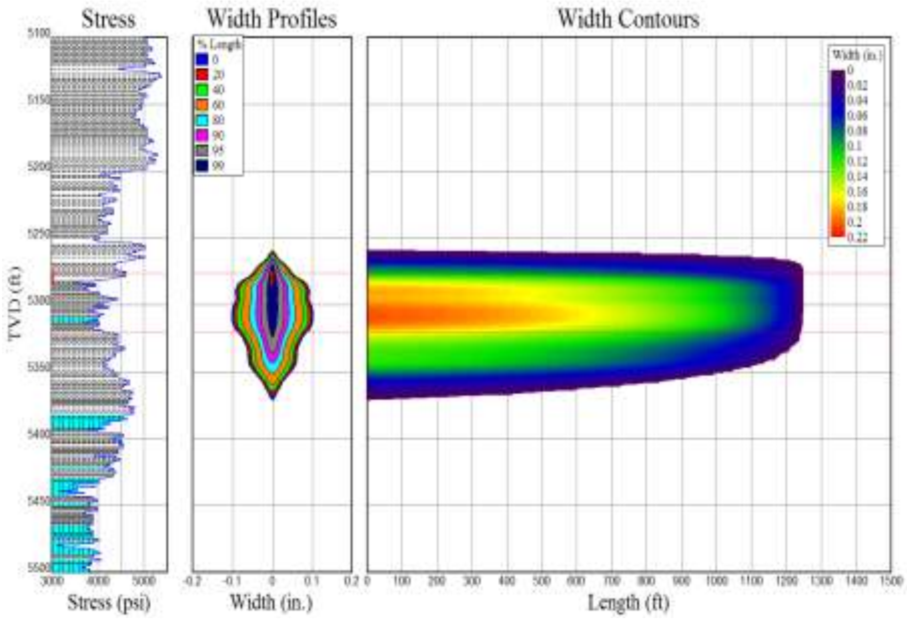


Figure 4

The model below (Figure 5) also shows a fracture that is contained by a lower stress interval with higher stress intervals above and beneath. It can be seen that the fracture half length is ~800’ and the fracture height is ~250’. A number of factors control the height growth of a fracture, but the relative difference between the stresses in and around the fracture is the most important factor. Fractures tend to remain in low stress vertical regions that effectively “lock in” or “trap” the fracture and keep it from breaking into higher stress rock. Staying in the reservoir rock is highly desired because remaining in the zone of interest maximizes the operators production and minimizes the wasting of frac energy on non-productive rock.

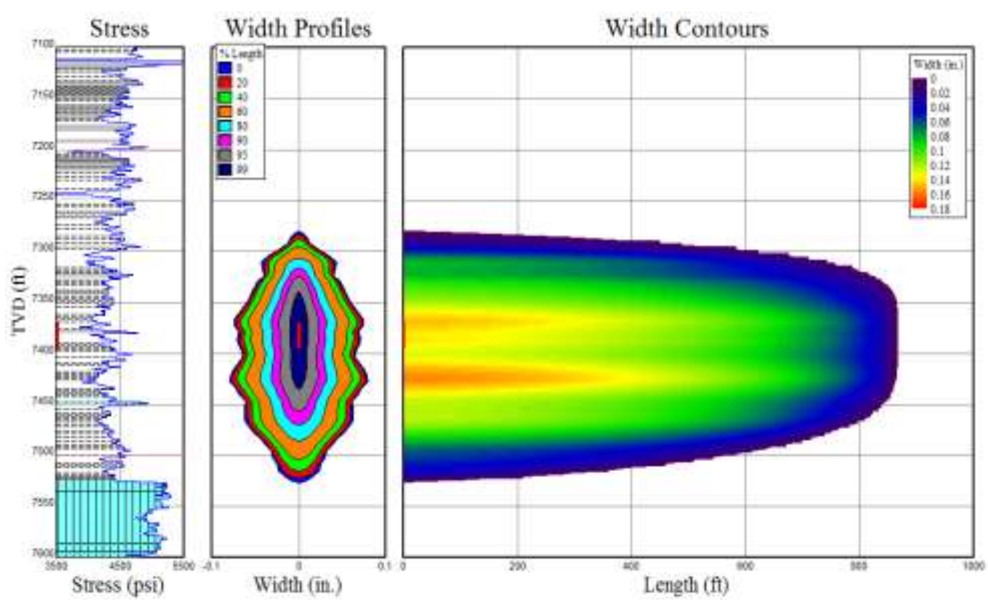


Figure 5

Perforation Clusters and Stage Spacing

The number of perforation clusters per stage and the spacing of the clusters are area and shale specific. In the majority of shale plays the perforation clusters are 50-100' apart. This spacing of perforation clusters is very dependent on a number of variables. More permeability and porosity typically allows for greater spacing between clusters. The greater the number of natural fractures, typically the greater the spacing between clusters. A lower stress anisotropy (which typically leads to greater frac complexity), typically results in a greater distance between clusters. In more ductile shales, the distance between perforation clusters will be shortened. Similarly, in a hydrocarbon liquids-rich play, where greater conductivity is typically desired, the distance between perforation clusters will be shortened.

Stage spacing typically correlates with perforation cluster spacing. In the majority of the shale plays 4-6 perforation cluster per stage is normal. The greater the number of perforation clusters, the less likely it is that each cluster will get adequately treated. Thus, limiting the number of clusters per stage typically leads to more stimulated reservoir volume. A typical stage length is 250–500 ft.

Fluid Selection

Many variables are involved in fracture fluid chemistry design (i.e., brittleness vs. ductility, highly anisotropic vs. low anisotropy, rate that can be achieved, fluid-rock sensitivity, etc.). Prior to pumping any fluid systems, fluid-rock core measurements are used to determine the fluid additives necessary in each play to prevent formation damage from drilling or fracture fluids. The majority of the shale plays in North America are treated with a large percentage of "slickwater". Slickwater is predominantly fresh water with additives (typically ~11 chemical additives) that constitute less than 1 percent by volume of the liquid pumped. Slickwater is frequently the fracture fluid of choice due to the lack of damage to the formation and its ability to increase fracture complexity within the shales, as compared to more viscous linear or crosslinked gels. Light gels are often used at the end of a stage to transport higher sand concentrations. In hydrocarbon liquids-rich plays, more gels are typically utilized to carry higher concentrations of coarser-grained proppant, allowing greater fracture conductivity.

Based on the nature of the induced fracture geometries, the volumes of fluids pumped, and the position of fractured intervals within the geologic column, Chesapeake Energy, the American Petroleum Institute and the American Natural Gas Alliance estimate that the risk of contamination to groundwater from hydraulic fracture stimulation of deep shale unconventional gas is extremely small to non-existent in most settings. However, we do realize that there are employees who routinely work around hydraulic fracturing additives and while safety is paramount in our industry, there is always the potential for an accidental surface spill. It was with the concern for our employees and the potential for spills in mind that we forged our "Green Frac" program.

Chesapeake Energy's Green Frac™ program was initiated in 2009 to determine if it was possible to improve the overall environmental "footprint" of the additives used in our hydraulic fracturing operations. A primary goal was to eliminate any additive that was not absolutely critical to successful completion and operation of our wells. For those deemed critical, materials have been selected that pose lower risk to personnel and to the environment in the event of an accidental surface discharge. To date, we have either eliminated, have found more desirable substitutes, or are in the process of successfully testing substitutes for the majority of additives historically used in hydraulic fracturing of unconventional shales.

Proppant Selection

Proppant selection is based on such factors as; the particular stresses to which the proppants will be subjected, the amount of fracture flow conductivity required, propped fracture length designed, and complexity estimated. Different proppants fit different plays and wells within plays. A 100-mesh sand is frequently used in the early portion of many hydraulic fracturing stages for diversion, etching, and as a propping agent. Larger 40/70- and 40/80-mesh proppants are presently the predominant proppants used in gas shales. Still larger 30/50- and 20/40-mesh proppants are used in some areas for conductivity enhancement. The larger proppants are especially important in liquids-rich environments. Resin-coated proppants are being used to “tail-in” for sand flow back mitigation and in areas where proppant strength and greater conductivity are needed. Similarly, ceramic proppants are being used for greater conductivity and strength. Optimum proppant selection is critical to well performance. If a sub-optimal proppant program is implemented that does not fit the application, production can be greatly curtailed.

Execution

Equipment for a “typical” multistage-stage fracture stimulation consists of 10-20 2,000-horsepower pumps, a blender, 2-4 sand storage bins, a hydration unit, a chemical truck, and 20-30 workers. After having considered all of the variables, a fit-for-purpose fracture design is pumped. With proper pre-job data gathering and the proper consideration given to the numerous parameters, the job is optimized for the given shale well.

Diagnostics

Microseismic monitoring, tiltmeters, gamma emitting agents, chemical tracers, production logs, temperature sensitive or acoustic fiber optics are all tools that can and are being used to evaluate what is happening downhole during and after the fracture stimulation job. These tools provide better understanding of hydraulic fracturing, and improve the hydraulic fracturing process. These topics will be discussed in detail by other authors at this workshop.

Summary

- Planning and executing an “optimum” hydraulic fracture requires a multidisciplinary approach to gathering data, evaluating the data and estimating reservoir and fracture properties, and designing and executing a fracture stimulation program.
- Using properly-gathered data, hydraulic fracture models can accurately predict vertical barriers and the resulting fracture geometry.

- Failure to appropriately design a given hydraulic fracture treatment can result in a sub-optimal to poor well stimulation and lower production potential, risking the millions of dollars invested in the well up to the point of stimulation.
- While the hydraulic fracturing of horizontal shale wells is relatively “new”, this highly engineered practice follows the same basic practices and science-based principals successfully used by the industry since the late 1940’s and implemented in tens of thousands of vertical wells since that time.