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Proceedings of the Technical Workshops for the Hydraulic Fracturing Study: Well Construction and Operation

U.S. Environmental Protection Agency

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Office of Research and Development
US Environmental Protection Agency
Washington, DC

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Introduction

The Hydraulic Fracturing Study

In its Fiscal Year 2010 budget report, the U.S. House of Representatives Appropriation Conference Committee identified the need for a study of the potential impacts of hydraulic fracturing (HF) on drinking water resources. The Committee directed EPA scientists to undertake a study of HF to better understand any potential impacts of hydraulic fracturing on drinking water and ground water. The EPA produced a draft study plan, which focuses on the key stages of the HF water lifecycle: water acquisition, chemical mixing, well injection, flowback and produced water, and wastewater treatment and waste disposal. This plan was submitted to the Science Advisory Board (SAB) in February 2011 and the peer review of the plan was held on March 7 and 8, 2011. At the time these technical workshop proceedings were developed, the SAB had not given its official review to EPA.

EPA has included stakeholder concerns in the planning process of the study from its inception, engaging stakeholders in a dialogue about the study through a series of webinars and facilitated public meetings held between May and September 2010. EPA also held four technical workshops in February and March 2011 to explore the following focus areas: Chemical & Analytical Methods (February 24-25), Well Construction & Operations (March 10-11), Fate & Transport (March 28-29) and Water Resource Management (March 29-30).

The technical workshops centered around three goals: (1) inform EPA of the current technology and practices being used in hydraulic fracturing, (2) identify research related to the potential impacts of hydraulic fracturing on drinking water resources, and (3) provide an opportunity for EPA scientists to interact with technical experts. EPA invited technical experts from the oil and natural gas industry, consulting firms, laboratories, state and federal agencies, and environmental organizations to participate in the workshops. EPA will use the information presented in this document to inform research that effectively evaluates the relationship between HF and drinking water.

An initial report of results from the EPA's study is expected by late 2012, with an additional report expected in 2014.

About the Proceedings

These proceedings provide an overview of the twenty-four presentations given on well construction and operations at the Technical Workshop for the U.S. EPA Hydraulic Fracturing Study held on March 10–11, 2011. This workshop consisted of three sessions or themes: Theme 1–Well Construction; Theme 2–Fracture Design and Stimulation; and Theme 3–Well Integrity. The proceedings include abstracts of the presentations and a summary of the discussions that took place during the workshop. The presentations from this workshop are not part of the proceedings document, but may be accessed at http://epa.gov/hydraulicfracturing.

This is the second of four technical workshops on topics relating to the EPA Hydraulic Fracturing Study. The other three workshops are: Chemical and Analytical Methods (Feb. 24–25), Fate and Transport (Mar. 28–29), and Water Resources Management (Mar. 29–30). Proceedings will be available separately for the other three workshops.

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. Any mention of trade names or commercial products does not constitute endorsement or recommendation for use.

Editorial Team for the Proceedings

The attendees at the Well Construction and Operations workshop were selected based on information submitted to EPA during the attendee nomination process. Presenters, a workshop lead, and theme leads were selected from the pool of attendees, once again, based on the information submitted to EPA during the attendee nomination process. The workshop lead, Scott Anderson of the Environmental Defense Fund, assisted EPA in finalizing details for the workshop and served as the lead editor of the proceedings document. The theme leads—Bob Whiteside of Texas World Operations for Theme 1, Tim Beard of Chesapeake Energy Corporation for Theme 2, and Jim Bolander of Southwestern Energy for Theme 3—served as editors for their respective themes.

Workshop Participants

Name		Affiliation
Ahmed	Abou-Sayed	Advantek International
Steve	Acree	US Environmental Protection Agency
Scott	Anderson	Environmental Defense Fund
Timothy	Beard	Chesapeake Energy Corporation
Chrystal	Beasley	US Environmental Protection Agency
John	Bolakas	Stantec Consulting Corporation
James	Bolander	Southwestern Energy
Jeanne	Briskin	US Environmental Protection Agency
Grant	Bromhal	US Department of Energy
Susan	Burden	US Environmental Protection Agency
Alan	Byrnes	Chesapeake Energy Corp.
Scott	Cline	Internal Revenue Service
David	Cramer	ConocoPhillips
Brian	D'Amico	US Environmental Protection Agency
Jill	Dean	US Environmental Protection Agency
Carolyn	Debrick	Devon Energy
Michael	Eberhard	Halliburton Energy Services
Terry	Engelder	Pennsylvania State University
Jay	Foreman	Williams Producton RMT
Bill	Godsey	Geo Logic Environmental Services, LLC
Richard	Hammack	US Department of Energy
Gang	Han	Hess Corporation
Patrick	Handren	Denbury Resources Inc
Brad	Hansen	Devon Energy Corporation
John	Harju	Energy & Environmental Research Center, University of North Dakota
Fred	Hauchman	US Environmental Protection Agency
Lloyd	Hetrick	Newfield Exploration Company
Charles	Hillenbrand	US Environmental Protection Agency
Anthony	Ingraffea	Cornell University
Mark	Jensen	Utah Department of Environmental Quality
Carey	Johnston	US Environmental Protection Agency
Jeff	Jollie	US Environmental Protection Agency
Bruce	Kobelski	US Environmental Protection Agency
Barbara	Kutchko	US Department of Energy

Name		Affiliation
Matthew	Landis	US Environmental Protection Agency
Hal	Macartney	Pioneer Natural Resources USA, Inc.
Jeff	McDonald	US Environmental Protection Agency
Carl	Miller	US Environmental Protection Agency
Briana	Mordick	Natural Resources Defense Council
Gary	Norris	US Environmental Protection Agency
Greg	Oberley	US Environmental Protection Agency
Jon	Olson	The University of Texas at Austin
Richard	Patterson	El Paso Exploration and Production
Steve	Platt	US Environmental Protection Agency
Robert	Puls	US Environmental Protection Agency
Randall	Ross	US Environmental Protection Agency
David	Russell	QEP Energy Co.
Daniel	Soeder	US Department of Energy
Gregory P.	Stanton	US Geological Survey
Mark	Stebbins	CNX Gas Company LLC
Talib	Syed	TSA, Inc.
Cody	Teff	Shell Exploration and Production Company
D. Steven	Tipton	Newfield Exploration Mid-Continent Inc.
Norm	Warpinski	Pinnacle - A Halliburton Service
Robert	Whiteside	Texas World Operations
John H.	Williams	US Geological Survey
Nathan	Wiser	US Environmental Protection Agency
Bryce	Yeager	Energy Corporation of America

Agenda

Technical Workshops for the Hydraulic Fracturing Study

Well Construction & Operations · March 10-11, 2011

US EPA Conference Center
One Potomac Yard (South Building)
2777 S. Crystal Drive
Arlington, VA 22202 Room S-1204 and 1206

March 10, 2011

7:30 am **Registration**

8:00 am **Welcome**

Jeanne Briskin, Hydraulic Fracturing Study Task Force Lead, EPA Office of Research & Development

Scott Anderson, Environmental Defense Fund, Workshop Lead

Pat Field, Facilitator, Consensus Building Institute

Theme 1: Well Construction

8:15 am **Technical Presentation Session 1: Considerations for Aquifer Protection**

Overview of the Well Construction Sessions, Bob Whiteside, Texas World Operations

Public Water Sources and Hydraulic Fracturing – A State Drinking Water Perspective, Mark Jensen, Utah Department of Environmental Quality

Well Completion Methods for Aquifer Protection, Bill Godsey, GeoLogic Environmental Services, LLC

9:30 am **Break**

9:40 am **Technical Presentation Session 2: Well Design**

Well Planning and Construction Techniques, Carolyn Debrick, Devon Energy

Production Casing Design Considerations, Brad Hansen, Devon Energy

Well Construction Practices in the Marcellus, Cody Teff, Shell Exploration and Production Company

10:55 am **Break**

11:05 am **Technical Presentation Session 3: Drilling and Completion**

Multi-Well Pad, Tight Gas, Directional Drilling Program Protects Aquifers, Jay Foreman, Williams Production

Casing Perforating Overview, Brad Hansen, Devon Energy

Cementing, Cement Quality Evaluation/Logs and Zonal Isolation for Hydraulically Fractured Wells, Talib Syed, TSA, Inc.

12:20 pm **Lunch**

Theme 2: Fracture Design and Stimulation

1:30 pm **Technical Presentation Session 4: Geologic Assessment**

The Distribution of Natural Fractures Above a Gas Shale: Questions About Whether Deep Fracture Fluid Leaks into Groundwater Outside the Realm of Faulty Borehole Construction, Terry Engelder, Pennsylvania State University

Evaluation of Well Records and Geophysical Logs to Determine the Presence of Freshwater, Saltwater, and Gas above the Marcellus Shale, South-Central New York, John Williams, US Geological Survey

2:30 pm **Break**

2:40 pm **Technical Presentation Session 5: Fracture Propagation**

Fracture Design in Horizontal Shale Wells – Data Gathering to Implementation, Tim Beard, Chesapeake Energy

Evaluating Hydraulic Fracture Propagation in a Shallow Sandstone Interval, David Cramer, ConocoPhillips

Hydraulic Fracturing in Coalbed Methane Development, Raton Basin, Southern Colorado, Hal Macartney, Pioneer Natural Resources USA, Inc.

3:55 pm **Break**

4:05 pm **Technical Presentations Session 6: Monitoring**

Monitoring a Frac Treatment – How Do We Know What is Going On?, Mike Eberhard, Halliburton Energy Services

A Case History of Tracking Water Movement Through Fracture Systems in the Barnett Shale, Patrick Handren, Denbury Resources

Measurements and Observations of Fracture Height Growth, Norman Warpinski, Pinnacle - A Halliburton Service

5:20 pm **Revisit the Major Discussion Points of the Technical Presentation Sessions**

Scott Anderson, Environmental Defense Fund, Workshop Lead

Bob Whiteside, Texas World Operations, Theme Lead – Well Construction

Tim Beard, Chesapeake Energy Corporation, Theme Lead – Fracture Design and Stimulation

5:45 pm **Adjourn for the Day**

March 11, 2011

Continuation of Theme 2: Fracture Design & Stimulation

8:00 am **Technical Presentation Session 7: Verifying Zonal Isolation**

Sustainable Fracturing Rationale to Reach Well Objectives - The Impact of Uncertainties and Complexities on Compliance Assurances, Ahmed Abou-Sayed, Advantek International

Design and Rationale for a Field Experiment using Tracers in Hydraulic Fracture Fluid, Daniel Soeder, US Department of Energy, National Energy Technology Laboratory

Review of Stimulation Water Retention Mechanisms and Likelihood of Fluid Communication with Shallow Aquifers, Scott Cline, Unaffiliated

9:15 am **Break**

Theme 3: Well Integrity

9:25 am **Technical Presentation Session 8: Pre- and Post-Hydraulic Fracturing Well Integrity Test Methods**

Assessment Methods for Well Integrity during the Hydraulic Fracturing Cycle, Jim Bolander, Southwestern Energy

Pre & Post Well Integrity Methods for Hydraulically Fractured/Stimulated Wells, Talib Syed, TSA, Inc.

10:25 am **Break**

10:35 am **Technical Presentation Session 9: Case Studies**

Case Study for Well Integrity over a Full Life Cycle, Lloyd Hetrick, Newfield Exploration Company

Risks to Drinking Water from Oil and Gas Wellbore Construction and Integrity: Case Studies and Lessons Learned, Briana Mordick, Natural Resources Defense Council

11:35 am **Revisit the Major Discussion Points of the Technical Presentation Session**

Scott Anderson, Environmental Defense Fund, Workshop Lead

Tim Beard, Chesapeake Energy, Theme Lead – Fracture Design and Stimulation

Jim Bolander, Southwestern Energy, Theme Lead – Mechanical Integrity

12:00 pm **Closing Discussions**

Susan Burden, EPA Office of Research & Development

Scott Anderson, Environmental Defense Fund, Workshop Lead

Summary and Abstracts from Theme 1: Well Construction

Summary of Presentations for Theme 1: Well Construction

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Technical Presentations

The first set of technical presentations in this theme addressed considerations for aquifer protection.

Bob Whiteside, Texas World Operations, described the three primary categories of well completion. Case 1 wells have surface casings cemented continuously from the surface down into water-bearing formations with waters having greater than 10,000 mg/L total dissolved solids (TDS). The casing and cement would extend through any waters with less than 10,000 mg/L total dissolved solids. Intermediate casing would be set through the surface casing to a greater depth. Case 2 wells have surface casing cemented continuously from the surface down into water-bearing formations with waters having greater than 10,000 mg/L TDS, but have no intermediate casing. In some situations, ground water protection can be enhanced through the use of an external casing packer. Case 3 wells have surface casings cemented continuously from the surface to depths within water bearing formations with water of less than 10,000 mg/L TDS. Mr. Whiteside noted that very few incidents of ground water contamination have been associated with Case 1 and Case 2 wells. Shallow Case 3 wells pose more of a challenge, but safety and aquifer protection can be ensured through proper planning, identification of artificial penetrations, careful geological study, and close attention to fracture procedures.

Mark Jensen, Utah Department of Environmental Quality, discussed the Utah Drinking Water Source Protection Program which is designed to help public water suppliers protect their drinking water wells, springs, and intakes. A source water protection plan delineates protection zones, inventories potential contamination sources, and develops plans to address current and future sources of potential contamination. In Utah, source protection zones are delineated based on ground water travel time or hydrogeologic boundaries. Land management strategies within the protection zones are developed and implemented by the public water system (PWS) and would be one part of a source protection plan that could consider hydraulic fracturing projects in the area. Mr. Jensen emphasized the importance of collaboration between the PWS, state agencies, and other groups.

Bill Godsey, Geo Logic Environmental Services, LLC, gave an overview of how conducting due diligence while following established industry standards on well construction and operations can ensure aquifer protection during HF operations. Conducting HF in a manner that protects drinking water resources relies on identification of aquifers and water wells, identification of potential migration pathways, and appropriate casing and cementing programs. Knowledge of adjacent oil and gas fields, as well as coal, lignites, and other mineral resources, is also important. Mr. Godsey concluded that HF can be conducted safely, ensuring aquifer protection, when there is appropriate site characterization and planning. Mr. Godsey also provided information the locations, areal extent, and general size of on major and minor aquifers in East Texas.

The second set of technical presentations addressed well design.

Carolyn Debrick, Devon Energy, discussed Devon's well planning and construction techniques used in the Haynesville Shale in East Texas. Ms. Debrick explained that the goal of drilling from an engineering perspective is to have good production for the entire life of the well. A properly designed well will meet this goal while performing in an environmentally safe manner. For example, casing should be designed to handle the loads incurred during drilling and the operating life of the well. Ms. Debrick emphasized the importance of successful primary cementation of surface casing. She noted that a remedial cement job is expensive and does not provide the same level of isolation as a primary cement job.

Brad Hansen, Devon Energy, described production casing and design considerations for safe and productive wells. He discussed three primary casing design factors: ensuring mechanical integrity, optimizing well cost, and providing well completion field personnel with the important design specification of maximum allowable loads. Before HF is conducted, it is important to know the maximum allowable fracture pressure. For this calculation, additional tension loads must be considered, such as those due to cooling of the production casing and to increased internal pressure, which may cause a ballooning effect on the production casing.

Cody Teff, Shell Exploration and Production Company, provided an example of Shell's well planning and construction techniques in the development of the Marcellus Shale to both identify and protect potential subsurface drinking water sources. Shell uses geologic information and seismic interpretation to identify and manage hazards that could compromise the integrity of the wellbore.

The third set of technical presentations addressed well drilling and completion.

Jay Foreman, Williams Production, discussed various engineering and regulatory controls intended to produce natural gas safely, economically, and in an environmentally sound manner. Proper procedures are intended to allow drilling and completion operations to be performed without endangering drinking water supplies. These procedures include cementing the casing and conductor pipe in place, evaluating wireline logs prior to HF, and closely monitoring downhole pressure.

Brad Hansen, Devon Energy, provided an overview of casing perforation. The primary objective of perforations is to create effective flow communication between the cased wellbore and a productive reservoir. The perforating gun consists of four components: a carrier, a shaped charge, the detonator cord, and the detonator. The impact pressure, which ranges from 10 to 15 million psi, overcomes the strength of casing and formation and forces material away radially, creating holes through the casing and pathways into the reservoir formation.

Talib Syed, TSA, Inc., discussed important aspects of well design such as cementing, cement quality evaluation and logs, and zonal isolation techniques. These are key factors for assuring wellbore integrity, which is important to ensure that production occurs in a controlled, safe manner and to prevent fluids from possibly migrating into underground sources of drinking water (USDWs).

Summary of Discussions Following Theme 1: Well Construction Presentations

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External casing packer. The presenters explained the importance of using external casing packers to create an external seal between the casing and the sides of the wellbore, as several transient pressures are created when a well is fractured. According to the presenters, the external casing packer provides another mechanism for preventing USDW contamination in Case 2 wells (as described by Mr. Whiteside). The presenters clarified the term “permanence” with respect to a seal. A presenter indicated that a good seal is above the fracture zone and will last in the range of 20 to 30 years. According to the presenter, the lifespan of a seal can be increased to 36 or 38 years if swellable packers are used.

Surface casing determination. A participant asked about determining the depth of surface casing and inquired about the process of safely putting surface casing through an aquifer or ground water supply. The presenters explained that the location of protected water is determined through maps and other sources of data and can vary depending on the state definition of “useable” water. One participant cautioned that the depth of usable water may not be the same as the depth of the bottom of the formation. Many states have specific depth requirements for surface casings.

Diagnostic tools to check for construction features. A participant asked whether there are diagnostic tools to check casing, proper cementation, and other design features, and if industry runs them routinely. The presenters stated that protecting water is industry’s responsibility and that they receive oversight from state agencies. According to the presenters, there is no current standard for running logs; this is dictated by local geology, the exploration/development phase of the field, and other criteria. Participants claimed that there are ways to drill wells in a manner that is protective of ground water and there is a movement in Texas for all drilling plans to be approved by a professional engineer.

Ground water modeling in fractured bedrock. A participant asked how ground water models are developed for fractured bedrock. In Utah, there are no requirements for the use of specific models, though the ground water modeling method must be applicable to the area of interest. A presenter indicated that locations of faults and the boundaries of aquifers are key components of hydrogeologic mapping. Analytical methods, such as calculated ground water travel time, are also used.

Contamination and drinking water well construction. The presenters clarified that well head protection is especially a problem for domestic water supply wells. According to the presenters, most contamination complaints concern domestic supply wells. Presenters claimed that there are often inherent problems with these wells. The presenters stated that results of most modeling studies and chemical analyses do not indicate contamination from subsurface migration. Instead, they stated their belief that contamination is more often linked to well head protection issues and cannot be attributed to oil and gas activities.

Fractures leaving the intended zone. Several participants asked about the number of times fractures have left the intended zone. They expressed concern about containment and assurance of fracture control. The presenters stated that shale in East Texas is approximately 100 ft thick, and that it is common for the first well to be fractured downward with respect to the target formation. Fracturing upward is done when there are many wells in the area. However, the presenters stated that operators are highly confident that fractures will not leave production zones. In the Eagle Ford Shale, depleted production zones above and below the gas reservoir act as barriers for pressure transmission and encourage lateral leakoff within the depleted zone. According to one presenter, the most significant concern is the impact to the wellbore as fractures propagating upward move closer to the well. Participants emphasized that staying within the intended zone is also important for production. One participant recommended core studies as a source of information on rock mechanics to provide fundamental information regarding fracture propagation.

Shallow gas sources and drilling with air. A participant asked about addressing the issue of shallow gas sources within or below a drinking water aquifer. The presenters stated that well design, drilling techniques and cement together can establish zonal isolation, which is especially important if there are shallow gas zones. There is concern about potential flow of the liquid components of the cement during cementation as the cement hardens; this flow was considered by participants to be one of the causes of channels and microannuli that can compromise the integrity of cement around the well. Guidance is available, for example from the American Petroleum Institute (API), on surface casing, cementing and drilling with air. Air drilling is sometimes conducted when installing surface casing and eliminates the need for drilling muds at relatively shallow depths. One participant noted that, in areas with a history of natural migration of gas, an operator's goal should be to not exacerbate any existing problems. A participant added that drilling with air does not seem to be exacerbating any gas migration issues in Pennsylvania.

Longer lateral sections of the well. Participants stated that longer lateral sections of the well allow greater gas recovery at lower cost and less surface impact. The presenters explained the importance of a longer lateral. According to the presenters, a longer lateral is a more effective use of surface facilities since it allows for more resource recovery without additional or bigger surface facilities and also reduces the number of wells that must be installed to drain the reservoir.

Best practices and information collection. Several participants asked about the identification and implementation of best practices. The presenters explained that some operators do meet occasionally to talk about wells and share best practices. A participant asked whether there is a standard or recommended process to collect information in a given zone and, although participants acknowledged the benefits to a standard process to ensure contamination does not occur, specific information to be collected was not mentioned. Other participants emphasized the importance of looking specifically at the available data and identifying data that need to be collected. Sources of information include the Society of Petroleum Engineers (SPE), the API, the American Association of Drilling Engineers (AADE), and state agencies. Participants noted that well design is constantly evolving and service companies are constantly developing new products.

Microannuli. Several participants asked about gas migration through microannuli over the life of the well. The presenters stated that pressure is drawn down and is lower at the wellbore during production. The objective is to draw gas toward and through the perforations so that gas will flow into the well; therefore, gas should not flow out through microannuli in the wellbore cement. The presenters noted the importance of taking remedial action during the drilling and construction phase to address any cement problems like microannuli. Several participants asked about the growth of microannuli over time. The presenters stated that they are not aware that microannuli grow over time. The presenters emphasized that the goal of maximum production is an incentive to fix any problems immediately as they occur. A participant stated that microannulus flow does not necessarily mean “micro” scale flow. Participants wondered whether that flow would impact ground water. According to one participant, it is not flow rate within microannuli, but rather leakage through the cement out of the wellbore, that is important.

Abstracts for Theme 1: Well Construction

Abstracts were submitted to U.S. EPA by the presenters for use in this proceedings document. Not all presenters submitted abstracts of their presentations.

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Overview of the Well Construction Sessions

Bob Whiteside, P.E.
Texas World Operations/Signa Engineer Corp

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Introduction

The extraction of hydrocarbons from shale and other low permeability formations using hydraulic fracturing technology has lead to the development of many new oil and gas reserves and many new environmental questions. Newspaper and television reports highlight water contamination cases, wildlife losses and surface water incidents on what seems like a daily basis. Environmental agencies, defenders of the environment, academicians and oil and gas professions are all searching for answers.

A portion of the of problem lies within the definitions and the terms of what is considered ground water and/or underground sources of drinking water. The Underground Injection Control Regulations (40 CRF 140-148) dealt with the same issues by defining a USDW as any formation containing water with less than 10,000 mg/l Total Dissolved Solids. While the UIC regulations deal with very limited numbers and specific type of wells, the oil and gas industry extracts hydrocarbons from where they are located within the subsurface. While most production wells are well above the USDW definition, a growing number of wells exist within the lower salinity formations. Some examples are wells in Wyoming which produce from formations containing 5000 mg/l TDS or coal methane wells located in formations that have much lower TDS's.

Eight presenters will give papers dealing with a range of topics which include regulatory concerns, well completion methods, casing design, cementing practices and testing methods. The session is constructed to give the listener a sense of what is currently being done within the oil and gas industry to protect ground water and introduce so of the latest techniques to enhance protection of human health and the environment. After each three presentation set, a question and answer period will follow. All participants in the workshop are encouraged to ask questions and seek answers during those times.

Well Settings in Texas

Well completion can be easily broken into three primary categories:

- Case 1: Wells that have surface casings cemented at depths containing waters greater than 10,000 mg/l TDS with intermediate casing set deeper
- Case 2: Wells that have surface casing cemented at depths containing waters greater than 10,000 mg/l TDS with no intermediate casing.

Case 3: Wells whose surface casings are cemented at depths less than 10,000 mg/l TDS

Case I Well Considerations

The deeper wells incorporate traditional designs and completions, which are adequate for ground water protection. Groundwater in the Class 1 scenario is protected by multiple layers of casing and cement. When standard API, SPE and industry standards are incorporated into the well design; little, if any, additional consideration is required to adequately protect groundwater.

In Texas, the Railroad Commission of Texas (RRC) prescribes the method of cementing, the number of centralizers, the excess quantity of cement required and other design considerations. The minimum and maximum depth the surface casing must be set at is prescribed by the Texas Commission on Environmental Quality (TCEQ). Operators are required, by law, to apply for and receive a drilling permit from the RRC and a letter entitled “Depth of Usable-Quality Water to Be Protected” issued by the TCEQ Surface Casing Team, Waste Permits Division before drilling can begin.

After the surface casing is cemented and generally 5 to 10 feet of new borehole has been drilled, a Formation Integrity Test (FIT) is performed. The FIT is a hydrostatic pressure test that is designed to determine if the surface casing cement job has adequate strength to drill further and if the formation in which the casing is terminated has sufficient strength to withstand any pressure event that might occur while drilling. If the wellbore passes the FIT, the well can safely be drilled deeper.

Once drilling has progressed through geological formations which lack sufficient strength to withstand expected production pressures or are too weak to support further drilling operations, an intermediate casing is set and cemented in place. Generally only the lower sections of these casings are cemented. Texas regulations require intermediate casing to be cemented from the bottom of the casing to a height above *… hydrocarbon or geothermal resource fluids* … (TAC, Title 16, Part I, 3, §3.7). The intermediate casing and cement provides additional layers to protect groundwater and decreases the probability of hydraulically fracturing into groundwater formations.

Case 2 Well Considerations

The shallower wells only have cemented surface casing covering the TCEQ-described useable water. Therefore, additional design elements have been added to reduce risk and avoid ground water incidents.

These wells have traditional surface casing and cementing designs. In some cases, enhanced ground water protection is achieved by means of an external casing packer (ECP). An ECP is an inflatable packer consisting of an inflation bladder, a deformable set of steel slats and an outer rubber covering. The ECP is screwed onto the bottom of the surface casing and run in the hole with the casing. Once the casing is set at its maximum depth, cement is pumped through the casing, around the outside of the casing, up the annulus and eventually exits the top of the wellbore. At the end of the cement column being pumped down the inside of the casing is a wiper plug to separate the cement from the displacement fluid. The wiper plug activates the inflation ports within the ECP body which allows fluid and pressure to enter and inflate the packer. Once the packer is inflated, a permanent mechanical seal is formed between the bottom of the casing and wellbore in the confining layer below the aquifer.

Examination of bond logs within the Eagle Ford field has shown a number of wells with “gas cut“ cement. When gas is entrained in the cement slurry during emplacement, channeling and contamination of the slurry can result in poor bonding. Hydraulic fracturing pressures can further degrade the cement column and, in extreme cases, impact the cement behind the surface casing. Incorporating an inflatable ECP in the production casing is one way to reduce the risk to ground water. The packer is inserted into the production casing with a mechanical port collar immediately above the packer. The ECP placed so that it will inflate and seal at the junction of the production formation and the formation above. The ECP is inflated by means of a tool run on a workstring. After inflating the packer, the port collar is opened to allow the annulus between the wellbore and the casing to be cemented.

Case 3 Well Considerations

The Case 3 wells are located in or adjacent to useable ground water (under any definition). Therefore, there is no way to protect useable ground water. The only thing that can be done is a comprehensive ground water study of all existing water wells in the area that are at a depth within 500 feet of the top of the production zone. A full suite of tests should be performed by a certified lab for metals, salts, and organics before any drilling or fracturing is performed. If the ground water is already contaminated by natural causes, an aquifer exemption should be issued.

Follow up testing should be required after fracturing activities. An area of review of approximately 3 miles should be a minimum with all water wells tested. If municipal water wells are involved, a reasonable "off-limits" distance should be applied (approximately 5 mile radius). The regulators and the operators should look closely at performing smaller frac jobs to limit height and more stages to limit fracture growth. The nearest water wells should be sampled within 50 to 60 days of the frac activity to determine impact and on a quarterly basis for a period of no less than 2 years. If water quality parameters in the water wells do not change, the operator should be safe in the assumption that impacts to the aquifer have not occurred as result of hydraulic fracturing. If any of the water quality parameters have changed, the state regulatory program may want to reconsider the value of the aquifer or require the operator to provide water from other sources.

Oil and gas production is always a matter of economics. If the operators feel there is no penalty, then they will drill shallow wells to make easy money. The real question is: "Do we need shallow production or do we save water resources?" In many cases, shallow wells may be profitable because the natural concentrations of salts, metals or other compounds are already elevated. Shale plays are growing in number every day. Do we have to produce all of them just because we can? The only true evaluation is the value of the hydrocarbon versus the value of the water. Currently operators are not really being forced to make those decisions but that does not means they shouldn't be forced to. With today's gas prices and an increasing gas supply, I believe that wells that produce gas with oil should be rated as more valuable to the energy market than just a well that produces "cheap gas" which may endanger the environment.

The Texas definition for “useable-quality water” is the same as Ohio and the UIC definition for underground source of drinking water (USDW) – ground water with 10,000 ppm TDS or less must be protected. Under those restrictions, it will generally be better for the operators to drill deeper and the ground water is no longer an issue.

Conclusion

Very few, if any, incidents of ground water contamination have been reported from the wells listed as Case I and Case 2. These wells generally are inherently safe because of the depth of useable water protected by surface casing and cement. Inexpensive enhancements can be added where the depth to useable waters is relatively close.

Case 3 wells pose a different challenge to the drilling engineer and the regulator. These wells can be made safe by careful planning, additional geological study, and close attention to fracture procedures. However, each well field must be considered on an individual basis. Texas uses the “aquifer exemption” regulations to determine if drilling and production from these fields can be conducted in a manner which is protective of human health and the environment.

Public Water Sources and Hydraulic Fracturing – A State Drinking Water Perspective

Mark E. Jensen
Utah Department of Environmental Quality / Division of Drinking Water

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The Utah Drinking Water Source Protection program is designed to help the public water suppliers to protect their wells, springs, and intakes. Source protection zones in Utah are delineated based on groundwater travel time or hydrogeologic boundaries. This delineation method requires site-specific hydrogeologic and source construction information. About 58 public wells, springs and tunnels are located in oil and gas fields, but over 200 public water sources are located in coal deposit areas. Land management strategies within the protection zones are developed and implemented by the public water systems, and the public water systems would be involved in potential hydraulic fracturing projects that may impact their water sources.

Well Completion Methods for Aquifer Protection

William E. Godsey, PG
Geo Logic Environmental Services, LLC

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Introduction

Hydraulic fracturing of highly variable hydrocarbon producing geologic formations can be conducted safely and in an environmentally protective manner using well established petroleum industry standards. Geologic, environmental and engineering characteristics have utilized numerous fracturing media and techniques that are used in a variety of applications. The industry standards, in conjunction with appropriate due diligence and inquiry in the area of the targeted area for hydraulic fracturing, can result in successful well completions and groundwater protection.

Purpose

The purpose of this presentation is to outline how appropriate due diligence can be undertaken concurrent with leasing, site acquisition, permitting and development of prospect areas to identify and mitigate potential pathways of frac fluids other than intended target zones. Identification of potential pathways for fluids will allow for drilling, completion and hydraulic fracturing and can identify potential areas of concern and provide the engineering and design of the well bore construction team the opportunity to prevent negative consequences, regardless of the depth of the wells.

Location

This presentation is applicable to any location where hydraulic fracturing is conducted. Examples and illustrations are taken from the State of Texas where numerous geologic and geographic settings exist as does a long history of hydraulic fracturing throughout hundreds of oil and gas fields and the completion of tens of thousands of wells. Examples of aquifer diversity and extent are illustrated from Texas and Oklahoma.

Methods

The methods utilized in this presentation include literature review, personal interviews and experience as a state regulator, as an oil and gas operator, as a consultant to industry, local, federal and state government, water supply corporations, mining companies and legal entities as expert witness. Graphical representations taken from data published by state agencies were used to illustrate specific site circumstances.

Appropriate Due Diligence

In many cases, once the prospect is developed and the leases are taken, it is up to the drilling and completion departments of the companies to drill and complete the well. The engineers responsible for the casing and cementing of the well have numerous factors to consider for the proper design of the well. Not only does the well have to be designed properly for the target zone to be completed and stimulated, but other factors must also be assessed. Among the factors to consider are near surface conditions and well pad stability. Well pad stability and near surface wash out is usually managed by setting of conductor casing. The uppermost aquifer and base of usable quality drinking water must be isolated and protected. Fresh water intervals are usually protected by the surface casing. Pressurized zones, or formations which produce oil and gas, between the surface casing and the total depth of the well must be isolated, too. An intermediate casing can be used to provide additional fresh water protection or isolation of productive and/or pressurized zones.

Research by others has shown that the fracture influence in deep shale gas is limited to a few hundred feet from the well bore. Fracturing in shallow coal beds for methane is a separate mechanism[1] from deep shale gas fracturing; however, the investigation for potential pathways is the same.

Aquifer Identification

Beginning at the surface, inquiries as to the types of aquifers present and the use of these aquifers is advised. The classification and definition of groundwater varies from state to state. Therefore, it is crucial to understand, the nature and areal extent of the hydrogeologic conditions of the area. Not all freshwater-bearing aquifers are utilized. Some of the aquifers have objectionable characteristics such as high iron or sulfate concentrations which render an objectionable taste, unless treated before consumption. Identification of large capacity municipal supply wells is suggested as these wells generally supply a large number of people as opposed to a single family.

Some aquifers are so massive that the water quality changes with depth as does the use of the water. Some fresh water aquifers are even known to produce hydrocarbons naturally and the same formation can be so extensive as to have water quality become brackish-to-saline and produce oil and gas as well, such as the Wilcox Formation.

[1] While general HF operations are similar for coal beds and shale, the details differ for HF operations in these different geologic settings. For example, in the presence of typical fracturing fluids, coal tends to swell which reduces permeability through fractures and, therefore, reduces production. To control coal swelling, the approach to fracturing coal beds can include the use of different fracturing fluid mixtures or gas-based (nitrogen or carbon dioxide gas) fracturing fluids. Fracture design can also be different because coal has a distinct natural system of fractures (cleats and joints), can have different stress and strain regimes, and can require significant dewatering prior to gas production. (Explanation provided by The Cadmus Group)

Water Well Inventory

Determining the number, types and utilization of water wells in the area of a well being hydraulically fractured can be cumbersome if sometimes nearly impractical for a number of reasons. Experience has shown from investigations of water well complaints that there are a number of issues that repeatedly come forth. The issues include a lack of information by the well owner about the well construction and age of the well, the company or person that drilled the well or other pertinent information. In many cases, there are other factors such as poor well head protection, poor casing quality and a lack of sanitation around the well. Other problems include poor drainage around the well and close proximity to septic systems, especially in rural areas not serviced by sanitary sewer systems.

Identifying wells that could be potentially impacted by fluids from a hydraulically fractured well, should they escape would be beneficial for any investigation. In most cases it is practical only to identify large capacity municipal water supply wells prior to beginning drilling. This information is usually available from state agencies.

Adjacent Oil and Gas Fields

Some areas where hydraulic fracturing may take place will involve penetration through shallower oil and gas fields. Deeper penetrations may exist through zones where fracturing is to take place. In either situation, evaluation of potential pathways for migration should take place to avoid conditions where fluid migration may occur. These zones have been proven to be effectively isolated by casing and cement in numerous applications. Identification of producing zones that occur at depths shallower than the target zone and especially immediately above the target zone is advisable. Examination of penetrations through the target zone to assure appropriate isolation is suggested as well.

Areas where oil and gas exploration have taken place also contain previous well bores which have been plugged and abandoned or drilled as “dry holes.” These well bores should be identified and evaluated as potential pathways prior to development of the target area. In most cases, these wells have been identified and are known by state regulators and are mapped accordingly.

Coal, Lignite and Other Mineral Resources

In numerous oil and gas producing areas, other mineral assemblages are also present. One of the most common mineral resources encountered is coal and lignite in near surface deposits. Both coal and lignite are known to produce methane naturally. When these mineral beds are highly fractured naturally and water moves through the units, minerals such as pyrite and other forms of iron and sulfur can form in the fractures giving the water an objectionable quality. Where these minerals are present in sufficient quantities, mining may have occurred in underground or near-surface operations. These activities should be noted when drilling in areas where coal and lignite resources are found. In some areas of Texas, drilling occurs in active mine areas and is compatible with mining activity.

Summary and Conclusions

Hydraulic fracturing can be conducted safely and aquifers can be protected when appropriate site investigation is conducted. There are many sources of information available for review. Once aquifers are identified and potential pathways for potential exposure are identified, appropriate casing and cementing designs can be implemented to address the specific site conditions. Hydraulic fracturing of geologic formations varies from region to region. Groundwater conditions and quality vary from region to region and protection/isolation techniques are available to address these variables. There are numerous approaches to hydraulic fracturing that involve various propping materials and delivery fluids. The key to successful hydraulic fracturing is identification of aquifers, location of potential pathways and appropriate casing and cementing programs to assure the frac materials remain in the target zone.

Well Planning and Construction Techniques

Carolyn S. Debrick, PE
Devon Energy

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This paper will focus on the well planning and construction techniques Devon uses in the Haynesville Shale. It will briefly cover issues that are related to designing and drilling the well safely and protecting subsurface drinking water sources. The goal as a Devon drilling engineer is to design the well for the maximum volume of fluids and pressure to be encountered while drilling as well as for the entire life of the well, and to do so in an environmentally safe manner.

Background

The Haynesville Shale is located in East Texas and North Louisiana. This paper will focus on Devon's well design and construction in the East Texas Haynesville Shale. This paper discusses an area covering six counties in East Texas. The depth of the shale varies from 10,500 ft to 13,500 ft. Pore pressure varies from an equivalent mud weight (EMW) of 15 pounds per gallon (ppg) to 18 ppg. Bottom hole temperatures range from 270 degrees F to 350 degrees F. Measured well depths range from 15,000 ft to 20,000 ft.

General Data Gathering

Before the well can be designed various data needs to be gathered and interpreted. The data gathered is as follows: pore pressure, fracture pressure, fresh water zones, temperature gradients, squeezing or unstable formations, depleted zones, disposal zones, sensitive shales, shallow gas hazards, presence of H_2S or CO_2, geologic targets, well interference data, minimum hole size required, production casing size required, completion design and fluids, topographic surface restrictions, and regulatory requirements.

General Well Design

The pore pressure and fracture gradient chart with the geological data is the basis for the entire well design. This determines how many casing seats will be required and consequently what diameter casing size is set at surface. The information is displayed in terms of EMW. The geological cross section is also included as some formations have higher or lower shoe strengths. There are empirical methods of determining pore pressure from logs and seismic data but the best information is from offset wells. Information on reservoir depletion due to production is also gathered and an estimated bottom hole pressure due to hydrocarbon withdrawal is determined. In East Texas, disposal wells that inject fluids may have higher than normal pore pressures. Information from the disposal well operators is gathered, and subsequently, a fracture gradient chart is created. Fracture gradient is a function of overburden and pore pressure but varies depending on the age of the rock and the in-situ stresses.

Equations generated over the years by industry experts can be used but actual offset leak off test data from the surrounding area is best.

For the Texas Haynesville Shale, Devon Energy uses more than three different well designs depending on where geographically the well is drilled. In Panola County, there is a high density of producing wells and some formations are depleted to an EMW of 2 ppg. In addition there are disposal zones that are charged above normal pressures. These factors impact the number of casing strings required to drill the well and the surface casing setting depth.

Directional Plan: Anti-Collision

Part of the early well planning process is to assess possible hazards such as potential collisions with existing well bores. Devon Energy looks at all offset wells including producing wells, abandoned wells, disposal wells, and any water wells.

Often Devon drills multiple wells off an existing pad or platform. In this case, survey data from each existing well to compare to the well that is being planned.

There are various surveying tools used to measure and determine the path of a well bore. Each of these tools has a degree of inaccuracy. This inaccuracy varies depending on the type of tool, (i.e. gyro vs single shot or magnetic). This uncertainty is translated into an ellipse referred to as “the ellipse of uncertainty”. It is assumed that the actual well bore can lie anywhere within the ellipse. The size of the ellipse of uncertainty depends on the type of tool run. Each type of tool has been assigned an “error factor” by experts that help determine the size of the ellipse. The anti-collision calculations take into account this “error” and adjust the ellipses accordingly. We can then examine the survey data combined with ellipses of uncertainty to asses any possible risk of collision.

Vertical wells can be legally surveyed using rudimentary angle only devices. While these basic surveys satisfy the legal requirements for surveying, they do not provide adequate information to track the well bore for anti collision purposes. If a well does not have adequate survey data we will survey the well bore in question to gather the necessary data to run anti collision calculations.

Drinking Water Source Identification and Surface Casing Setting Depth

In Texas, the Texas Commission for Environmental Quality (TCEQ) maintains data on drinking water protection zones and water wells. TCEQ defines the location of the base of underground source of drinking water (USDW) and identify water source wells within one-quarter mile. The USDW in East Texas is typically at the base of the Wilcox formation. This depth can be as shallow as 250 ft or as deep as 1650 ft or more. Surface casing is to be set within 200 ft below these zones.

Devon not only considers the depth of drinkable water when determining surface casing setting depth but also considers what maximum pressure that can be held at the surface in a well control event and not break down the shoe. This pressure is referred to as maximum anticipated surface pressure (MASP). With shallow shoe depths this pressure is very low (see Table 1 below).

Table 1.

Shoe Depth (feet below surface)	Fracture Equivalent Mud Weight (lb/gal, or ppg)	Planned Mud Weight (lb/gal, or ppg)	Maximum Anticipated Surface Pressure (lb/in^2 or psi)
600	11.5	10	47
1000	12.5	10	130
1500	13.5	10	234

In Panola County, the depth of the base of the Wilcox is between 250 ft to 350 ft. Based on these depths and TCEQ requirements the surface casing would be set 450 to 550 ft below ground surface respectively. Devon requests an exception to set surface casing deeper for safety considerations. Devon sets surface casing shoes in East Texas deeper than prescribed by the regulator for two reasons: 1) to provide additional USDW's protection; and 2) to provide sufficient kick tolerance for drilling ahead.

Casing Design Considerations

The goal of the casing design is to provide a safe and reliable design. The design depends on the loads that may occur. Major design considerations are drilling loads, casing running loads, fracture stimulation loads, connection selection, buckling, corrosion issues, temperature related issues, and compressive loads on surface. Any part of the casing that is not cemented is subjected to dynamic well conditions and casing movement due to temperature, pressure, and fluid gradient changes. The selection of the top of cement is based on these considerations.

Connection selection is critical. Most casing failures occur in the connection. Bending, compression, tensile, and fatigue life when rotated are considered.

For surface casing the connection needs to also be able to support the weight of all the casing strings and the applied loads associated with the well life. If the compressive loads exceed the safe rating of the connection, a base plate is installed on the surface casing head.

Cementing Surface Casing

Obtaining a good primary cement job is critical to Devon. Remedial cement jobs are costly and typically do not provide the same level of isolation. In East Texas we utilize Class A cement for surface casing. This cement can develop compressive strengths at lower temperatures. Typically 300 ft of 15.0 ppg neat cement with no fillers is placed on bottom and followed by a lighter weight 12.6 ppg cement with extenders and accelerators to achieve minimum compressive strength before drill out. The hydrostatic density of the cement column when the cement is in its fluid state must not exceed the formation fracture strength. Casing is centralized with bow type centralizers -- one every joint for first 4 joints and one every third to surface. Haynesville field practices to ensure a good cement job include: conditioning mud before tripping to run casing, running a spacer before the cement, and moving pipe while cementing. Cement is circulated to surface on all these jobs or a top out job is conducted.

Once the cement is set and the shoe is drilled out, a formation leak off test or integrity test is conducted. This is to ensure that a good cement job was accomplished and that the shoe and formation at the shoe has sufficient strength to drill to the next casing seat.

In addition, due to the current and potential for future disposal wells in East Texas, we bring cement on the next casing string into the surface casing shoe if the formations in the open hole can hold the hydrostatic column of cement.

Casing and Cementing Horizontal Production Casing

Additional design and planning is required for the Haynesville due to the long measured depth of the well, the close tolerances of casing to hole diameter, and the high mud weights. Devon runs a tapered 5.5” by 4.5” casing string in 6-3/4” hole and the typical mud weight at total depth is 15 to 16 ppg. In terms of cementing, the same field practices apply here as with surface casing. However, mud and cement rheology are critical in this situation. Prior to pulling out of the hole to run casing a good practice is to condition the mud to as low plastic viscosity and yield point as possible. Surge and swab is run to determine the casing running speed. Calculations are also made on the cement job with the cement and mud rheologies to determine the maximum pump rate which is usually low. We add rheology improving products in the cement as well as expander and strength retrogression products. However we still can lose returns while running casing in the hole or cementing. If there is risk that cement will not reach inside the intermediate we run a swell packer just above the intermediate casing shoe. This packer will swell to the casing internal diameter in a maximum of 2 weeks.

This swell packer provides isolation between the two casings. The fracture treatment pressures for the Haynesville Shale can be as high as 13,000 psi. Back pressure is held on the casing when possible for safety reasons during the fracture treatment job. In addition the swell packer provides isolation from any gas in the open hole.

Cementing Intermediate Casing

Typically the intermediate casing string has pay zones behind pipe. When possible we bring cement inside the surface casing shoe. If this is not possible we run a cement bond log prior to perforating and stimulating any zone in this casing string.

Production Casing Design Considerations

Brad Hansen
Devon Energy

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This abstract presents information to consider in the design of a safe and effective production casing string for well production and also as a conduit for a fracture stimulation. The presentation discusses casing design factors and casing design loads. Pipe performance is discussed as well as material selection. A description of the various types of casing connections is given. Also, additional considerations that should be addressed if the well will be hydraulically fractured down casing are discussed.

There are three major requirements to be considered in designing production casing:

1) Ensure the well's mechanical integrity
2) Optimize well costs
3) Provide operations personnel with the maximum allowable loads

Many factors enter into the production casing design. These include the mud weights required to drill the well and balance the formation pressures, the fracture gradients, casing seat depths, casing sizes, the directional plan, the cement program and the temperature profiles. Also, the type of fracture fluid and proppant to be used, maximum proppant concentration, and the calculation for the maximum anticipated hydraulic fracture surface pressure should be considered. The types, composition, and volumes of the anticipated production must also be considered. This information is used to determine the planned loads over the life of the well.

Once these expected loads are determined, the pipe selection can be made that will meet or exceed the minimum design factors required by the designer. The design factor is the pipe rating divided by the anticipated load. This design factor must meet or exceed the minimum design factor that the designer has set. Most pipe ratings are based on the yield strength of the pipe. To determine the yield strength of a given material, a specimen is machined and put into a load cell where tension is pulled and the strain measured on the sample until it fails. A stress-strain curve is then generated. The yield strength using the API method is defined as the stress at a strain of 0.5% elongation. This yield strength is less than the ultimate strength of the sample.

There are two main design cases for internal yield pressure of production casing. One is modeled with a tubing leak near the surface with the shut-in tubing pressure added to the packer fluid weight as an internal load. The shut-in tubing pressure is estimated from the bottom hole pressure minus the weight of the gas in the tubing. The weight of the gas in the tubing is calculated both at static and at flowing temperatures (sometimes called a hot shut-in)

The other internal yield pressure case is injection down casing such as during a hydraulic fracture stimulation. The internal pressure is modeled by the applied surface pressure and the fluid gradient based on the fluid being pumped. This is analogous to a hydraulic fracture screen-out downhole since fluid friction down the casing is not subtracted from the internal pressure profile. The external casing pressure profile is modeled with the mud gradient from surface to the top of cement. Then the gradient from the cement mix water from that point to the outer casing shoe. From the outer casing shoe to total depth (TD), the external pressure profile is the pore pressure profile.

Production casing collapse loads assumes zero pressure on the inside of the pipe and a final mud weight gradient on the outside of the casing.

Rated internal yield pressure of casing is calculated using the Barlow Equation below:

- P = 0.875 * [2*Yp*T]/D
- P= internal yield pressure or burst strength (psi)
- Yp = yield strength of the pipe (example P110 is 110,000 psi)
- T = nominal wall thickness (inches)
- D = nominal outer diameter of pipe (inches)

Per API, the calculated number is rounded to the nearest 10 psi. The 0.875 factor in the above equation represents the allowable manufacturer's tolerance of minus 12.5% on wall thickness per API specifications.

Collapse ratings on API tubulars are derived from four different equations based on the outside diameter / thickness ratio and the yield strength of the pipe.

Axial strength of the pipe body is calculated from the formula below:

- Fy = (π/4) * (D2 – d2) Yp
- Fy = tension strength (lbs. rounded to the nearest 1,000)
- Yp = yield strength of pipe (psi)
- D = OD of pipe (inches)
- d = ID of pipe (inches)

Calculations for joint strength can be found in API bulletin 5C3. Published joint strength of API connections is based on the ultimate strength of the pipe and not the yield strength. Most, but not all premium connections are based on the yield strength of the connection.

API Spec 5CT is the Specification for Casing and Tubing. The different grades of API pipe specify a minimum and maximum yield strength. A maximum hardness is also specified from grades designed for sour service.

The chemical composition of the different grades of API casing is also specified. Grades designed to work in sour service have more stringent chemical requirements.

Sour service is defined by the National Association of Corrosion Engineers or NACE, as an environment where the partial pressure of H_2S exceed 0.05 psia. The total pressure must also exceed 65 psia for a gas well and 265 psia for an oil well. The NACE standard MR0175 and the ISO standard 15156 specify material to be used in sour service. In summary, API casing grades H40, J55, K55, M65, L80, C90 and T95 are good for all temperatures. N80 is good above 150 degrees F, P110 is good above 175 degrees F and Q125 is good above 225 degrees F.

Casing connections represent less than 3% of the pipe length yet account for more than 90% of pipe failures. Also, the connection represents 10% to 50% of the total tubular cost.

API connections STC (short thread and coupled) and LTC (long thread and coupled) each have 8 threads per inch and have rounded crests and roots. On LTC, the tread section is longer so it will have better sealability and tensile strength than STC.

A buttress connection is another API connection that has 5 threads per inch. It is not symmetric for the load and stab flanks.

There are several types of premium connections available, but most fall into one of the following categories:

A metal to metal seal thread and coupled connection generally has the internal yield, collapse, and tension ratings equal to the pipe body.

An integral joint connection has half the leak paths of thread and coupled connections. Also, the connection outer diameter (OD) is significantly smaller than a coupled connection. It also features a metal to metal seal. The joint strength of an integral joint connection is usually 70 to 80% of the pipe body.

A flush joint connection is approximately the same OD as the pipe body. Its joint strength is usually only 45 to 60 % of the pipe body strength in tension.

Prior to the hydraulic fracturing of a well, the maximum allowable surface fracture pressure must be calculated. The fluid gradients inside and outside the pipe are needed to make this calculation. Not only must the burst (internal yield) pressure of the pipe be considered when making this calculation but also the effect of the internal hydraulic fracturing pressure and hydraulic fracture injection rate on tension. The internal pressure during the hydraulic fracture causes a ballooning effect on the production casing that adds to the tension load. During the fracture, the production casing is cooled[2] by the injection of fracture fluids, which also adds to

[2] Fracture fluids stored at the surface will be near surface temperature, which is generally a much cooler temperature than the bottom hole temperature.

the tension load of the production casing. These additional tension loads must be taken into consideration when determining the maximum allowable hydraulic fracture pressure.

Shell's Well Construction Practices in the Marcellus Shale

Cody Teff
Shell E&P Company

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Introduction

This paper is about the well planning and construction techniques that Shell uses in the development of the Marcellus Shale to:

- Identify potential subsurface drinking water sources (private and municipal)
- Protect them through hazard avoidance (target zone planning) and zonal isolation

It will include location selection, directional planning, casing selection and design, cement slurry design, and integrity testing prior to fracture stimulation.

Background

The Marcellus Shale is a laterally contiguous shale deposit that covers parts of Pennsylvania, West Virginia, Ohio, New York, and Virginia. This shale has been proven to contain commercially viable natural gas resources and thus has entered the development phase of a hydrocarbon resource. As part of the development technique, hydraulic fracturing is utilized to enable production of natural gas at commercial rates. This technique allows for high conductivity fractures to be created, or natural fractures to be supplemented, that allow higher flow surface areas to connect to a wellbore. In order for fracturing operations to commence a wellbore must be drilled to the appropriate location with the appropriate equipment to allow integrity and control during the fracturing operation.

Drinking Water Source Identification

The process for the identification of sub-surface drinking water sources starts when a well location to be drilled has been identified. This process begins with a spatial and title review to identify offsetting land owners or potential users of sub-surface water for consumption or other use. Once the spatial and title review have been completed a survey is conducted, via registered mail, to determine if people within 1,000' of the proposed drilling location have sub-surface water source wells. If sub-surface water wells are present then information about the depth of the well is gathered. Additionally a request to conduct a base line survey (Table 2), including gathering a sample, is requested from the owner or user of the sub-surface water well.

Well Directional Planning

The directional planning of oil and gas wells are undertaken to hit subsurface targets and avoid subsurface hazards that could compromise the integrity of the wellbore or the ability to reach the final objective. There are two basic approaches that are used to identify hazards, the first is by geologic interpretation and the second is by seismic interpretation. Geologic interpretation uses the latest data available to continually improve the model. The basic inputs are surface data, including topography and outcrop information. As information on new wells is gathered this model is improved to grow the understanding and improve future interpretations. The seismic interpretation is based on the acquisition of seismic data, or the acoustic response of subsurface features to a surface event. Examples, not all inclusive, of subsurface hazards to potentially avoid when performing directional planning would be faults, shallow gas, and shallow water flows.

Zonal Isolation

Zonal isolation is generally accomplished through the use of steel casing that is cemented in place for the purpose of structure and annular isolation. The steel casing is typically designed for the anticipated operating loads to which it will be exposed, including running, future well construction activities (including hydraulic fracturing operations), and production operations. The annular area outside the steel casing is cemented to support the pipe and help control some of the loads (e.g. buckling). The cement is also used to control flow in the pipe annulus. The cement is engineered for specific properties, including but not limited to, set up time, compressive strength, and viscosity.

Conclusion

All of the practices represented in this paper are built on a back bone of Health, Safety, Security, and Environmental (HSSE) management. These practices comply with regulations and incorporate best industry practices. Hazard identification and management are core to the sustainability of our operations. At Shell, safety is a deeply held value that is demonstrated by our pursuit of “Goal Zero”, or the goal to have a zero incident work environment.

Table 2. Parameters analyzed during baseline water survey

Test	Holding Time (with Preservative)
pH (Lab)	Immediate
Alkalinity	14 days
Chloride	28 days
Hardness	6 months
Sulfate	28 days
Total Dissolved Solids (TDS)	14 days
Total Suspended Solids (TSS)	7 Days
MBAS/Surfactants	48 hours
Nitrate-Nitrogen	
Turbidity	Immediate
Specific conductance	
Barium	6 months
Calcium	
Iron	6 months
Magnesium	6 months
Potassium	6 months
Sodium	6 months
Arsenic	6 months
Cadmium	6 months
Chromium	6 months
Lead	6 months
Mercury	28 days
Selenium	6 months
Silver	6 months
Bromide	
Strontium	
Oil and grease	28 days
Benzene	14 days
Toluene	14 days
Ethylbenzene	14 days
Xylene	14 days
Ethylene glycol	
Total coliform	
E. coli	
Fecal coliforms	
pH (Field)	
Methane (% in atmosphere; well head space)	
Methane (% of LEL; well head space)	
Methane (in water)	7 days
Ethane	7 days
Propane	

Multi-well Pad, Tight Gas, Directional Drilling Program Protects Aquifers

Jay Foreman
Williams Production RMT

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Engineering and regulatory controls are in place in the oil & gas industry specifically in Colorado to ensure that completions operations for natural gas wells are conducted safely, cost effectively, and in an environmentally sound manner. This includes making sure that hydraulic fracture treatments go into and stay in the targeted zones where they will help stimulate oil or gas production. As a Completions Manager for the Piceance Asset, my job is to manage the engineering and operations activity required to turn a drilled well into one that produces natural gas safely and economically. Once a well is drilled, the casing is cemented in place and the drilling rig leaves the site. A completions engineer then examines the logs and specifics of the wellbore to design the perforating and stimulation procedures required to extract natural gas from subsurface rock strata. Since the reservoir rock is so impermeable, natural gas will not typically flow out of the reservoir at economic rates. Therefore, hydraulic fracturing (frac'ing) is required to "stimulate" the formation to produce natural gas. Proper well construction is critical to isolating the subterranean layers during completion and production operations. Not only is this important for keeping the frac treatments in the reservoir but for keeping unwanted water out of the gas zones. All aspects of drilling and completing wells are regulated by the Colorado Oil and Gas Conservation Commission (COGCC) and, if applicable, the Bureau of Land Management (BLM). In this document and the associated presentation given at the EPA's Well Construction Operations Workshop, these two agencies' regulations will be collectively referred to as State regulations. I will discuss well construction, cement design, and zonal isolation relative to our directional, multi-well pad development program on the Western Slope of Colorado. Water wells in the area are typically less than 250' deep yet our surface casings are set at well below this depth with cement circulated to surface. Some pads have over 20 wells on 7-1/2' centers so directional work begins as shallow as 100'.

Conductor pipe (+/-45') and surface casings (>10% of the TD of the permitted well depth) are set before the production interval is drilled. The drilling mud in the annulus of the 9-5/8" diameter surface casing is displaced with cement engineered to meet State requirements. After the cement has cured and developed the required compressive strength, a smaller drill bit is used to drill out the bottom of the surface casing and drill the well to the permitted depth. Once a well is drilled and conditioned, the drill pipe is removed and 4-1/2" diameter production casing is run to the total depth (TD) of the well. At that point, the drilling mud in the hole is circulated for several hours to "condition" the hole and prepare it for cementing operations. Production casing of a specified grade and weight (wall thickness) is run such that its resulting burst pressure rating is greater than the anticipated operating pressures during the subsequent completion. Casing design is an area of engineering expertise and is addressed extensively by State regulations. The American Petroleum Institute has developed strict specifications for the manufacture of oilfield tubulars including casing. The design burst pressure of the casing string in a wellbore is duly noted by the operating company's staff and contractors and the maximum allowable treating pressure (max pressure) is established and known by all who work on the well for the remainder of its productive life. The pressure is not to be exceeded in order to protect the mechanical integrity of the wellbore.

The well is cemented with specially engineered cement with known density, thickening time, fluid loss, free water, and compressive strength. These parameters are based on bottom hole circulating and static temperatures and must meet State requirements. It is worth noting that manufacturing and testing specifications for completion cements are much more stringent than for cements used in construction projects. The API has established guidelines for all aspects of the cement and cementing operations to which operating and service companies adhere. The volume of cement pumped on the primary cement job is determined by isolation requirements for the zones to be completed as well as applicable State requirements for height of cement in the casing annulus. The cement is pumped down the casing and displaced with water behind a wiper plug. Once in place, the cement cures, getting hard and building compressive strength.

After the drilling rig leaves the well and sufficient time has passed to ensure proper cement compressive strength development, a cement bond log (CBL) is run to evaluate the quality and height of cement fill in the casing annulus. It is evaluated by the completions engineer to determine if the completion operations can be safely and effectively completed on the well. If not, the completion procedure will be altered to include remediation procedures to repair the primary cement job or to even exclude some zones from completion. In either case, the objective is to prevent undesirable communication between zones in the annulus.

Regulators are notified of the start of completions operations. The CBL is submitted to regulators prior to the first frac and any deficiencies with annular fill or cement bond quality are discussed. Calibrated pressure gauges are used to determine if pressure exists on the annulus of the production casing. If the annular pressure limit set by regulatory agencies is exceeded, they must be notified and remediation plans developed, sundried, approved, and executed.

The geologist and completions engineer evaluate the wireline logs to determine how the subsurface zones will be grouped together into frac stages, perforated and hydraulically fractured. The completion procedure is written, capturing critical information such as perforation depths, plug specifications and depths, frac job volumes, rates, proppant concentrations and volumes. All completion procedures note the casing specifications and the max pressure which is not to be exceeded. Treatments are engineered to minimize waste of materials while maximizing production. This can be based on fracture simulation programs and/or on field experience considering production results and the market costs of services and materials. Before any perforating begins, the production casing is pressure tested to the maximum allowable pressure. The test is recorded and submitted to the State. A well that fails the pressure test must be remediated in accordance with plans submitted to and approved by regulatory agencies.

The day of the first frac arrives and the frac crew gets the necessary equipment rigged up to the wellhead. Prior to any hydraulic fracturing treatment, all personnel on location are gathered for a prejob safety meeting where each person’s job responsibilities are reviewed. A headcount is taken and emergency egress procures are reviewed. These meetings even go so far as to designate a driver and note the closest medical facility in the unlikely event that someone is injured during the operation. During this meeting, it is clearly stated who is to “control” the job. One service company supervisor/ engineer and one company representative will be in complete control of the location during the job.

Max Pressure is discussed with all pump operators. Radio communication between all critical crew members is confirmed to ensure job control is maintained at all times.

Specifically engineered pressure gauges (typically 15,000 psi working pressure) and backup gauges are placed on the high pressure treating lines near the wellhead to monitor the treating pressure. Once every person is in their place, the high pressure pumps and lines (typically either 10,000 or 15,000 psi working pressure) are primed and pressure tested to the wellhead above max pressure for the job. Each pump has its own pressure gauge and "trip out" that is checked . This safety device will automatically shut the pump down if treating pressure exceeds the preset limit. A "global kickout" is also set on the control computer in the treatment control van where the two people in charge of the job can safely and comfortably monitor and control all aspects of the job. The global kickout will automatically shut down all pumps should treating pressure reach max pressure. The treatment design is programmed into the computer control system. All blending and pumping equipment on location can be run from the control van by the computer system or manually overridden as job requirements or well response determines.

Low pressure/ high accuracy pressure gauges are used to monitor the pressure on the annulus of the production casing during the treatment. Should annulus pressure rise beyond predetermined limits, the job will be aborted immediately and the situation evaluated. Regulators will be notified of any such event.

Once all safety systems are checked, the wellhead valves are opened and the pumping begins. A "pad" volume greater than wellbore volume is pumped at treating rate until the treating pressure stabilizes. At that point, the injection is stopped and an Instantaneous shut-in pressure (ISIP) reading is taken. Calculations are made from this wellhead pressure to determine how many perforations are open and accepting frac fluid. In addition, a formation frac gradient is calculated and compared to the anticipated frac gradient from the prejob simulation or experience in the area. If all perforations are open, the treatment proceeds. If not, the completion engineer may be consulted and the job can be redesigned if necessary.

During the remainder of the treatment, wellhead treating pressure, casing annulus pressure, and equipment performance are all closely monitored. While all are important, the most critical parameters are the actual wellhead treating pressure vs. anticipated treating pressure and max pressure. The pressure trends throughout the job give clues to what is occurring downhole. Dramatic increases in pressure may indicate that zones are "screening out" and no longer accepting fluid. Dramatic decreases in treating pressure may indicate an equipment problem either on surface or downhole. Subtle pressure changes can give clues to chemical performance as well as fracture growth in the formation. Should treating pressure rise and approach the Max Pressure, the two people in charge of the job will discuss and slow injection rate to reduce pipe and perforation friction and the resulting wellhead treating pressure. In some cases, rate changes in response to the well pressure are sufficient to allow the entire job design to be pumped and flushed. In other cases, the well "refuses" to accept the designed treatment and the job must be terminated early to prevent exceeding max pressure and damaging the wellbore or surface equipment.

Treatment placement can be validated in several ways.

- The first is by monitoring the wellhead pressure during the treatment.
- Secondly, the actual treating rates, pressures, and concentrations can be loaded back into the fracture design simulator. The simulator can then be "calibrated" to match the actual treatment data. Once a "good" match is obtained, the fracture dimensions of the simulation can be evaluated.
- Thirdly, tracers can be run in the treatment and post-frac logs run to determine if unanticipated fracture height growth had occurred.
- Lastly, microseismic monitoring from a nearby wellbore can give direct indication of the fracture height, length, and azimuth. With this service, arrays of sensitive geophones "listen" for the minute sounds of the hydraulic fracture growing through the reservoir rock. The location of these events can be calculated and plotted as dots on a three dimensional display. All the events recorded during the treatment are plotted vs. time for a representation of how the fracture grew throughout the treatment. These costly, non-routine monitoring projects are done for specific engineering purposes. The results can be used to further refine the fracture simulator and enhance the geologist's and completion engineer's general knowledge of fracture growth in the area.

Finally, the annulus pressure of the production casing is monitored during the treatment to ensure no communication occurs up the backside.

The plug/perf/frac process is repeated until all the frac stages are completed. The well is then cleaned out, production tubing landed, and the well is turned to production. The final analysis of the success or failure of the fracturing process comes from the production results.

Casing Perforating Overview

Brad Hansen
Devon Energy

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This paper provides a general overview of casing perforating. The primary objective of a perforating gun is to provide effective flow communication between the cased wellbore and a productive reservoir. To achieve this, the perforating gun "punches" a pattern of perforation through the casing and cement sheath and into the productive formation.

In the early days (1932) perforating was performed with a bullet gun. Today the bullet gun has been almost completely replaced with the shaped-charge perforator. The shaped charge consists of a case or container, the main explosive material, and a liner.

The perforating gun consists of four components, a conveyance for the shaped charge such as a hollow carrier, the individual shaped charge, the detonator cord, and the detonator.

The three main explosives used in a shaped charge are RDX (Cyclotrimethylene Trinitramine), HMX (Cyclotetramethylene Trinitramine), and HNS (Hexanitrosilbene). The main difference between these explosives is their temperature stability. RDX is commonly used in environments less than 330 degrees F. HMX is used for temperatures up to 400 degrees F and HNS is suited for temperatures up to 520 degrees F. Each shaped charge generally contains between 3 and 60 grams of explosives.

A shaped charge perforating gun detonates almost instantaneously when the electrical charge is sent from the perforating truck. The detonation creates a jet that has a velocity of 25,000 to 30,000 ft/second. The impact pressure caused by the jet is approximately 10 to 15 million psi. This pressure overcomes the casing and formation strength and forces material radially away from the jet axis.

Most perforating guns punch holes with diameters of 0.23" to 0.72". The typical perforating guns have penetrations of 6" to 48". Most guns shoot from 4 to 12 shots per foot. Perforating guns come with different pressure and temperature ratings.

The length of the actual perforation downhole is a function of the standoff of the perforating gun from the casing. Less standoff generally means a longer perforation tunnel, while more standoff results in a shorter perforation tunnel. Phasing is the angle difference between successive perforations. Typically, perforating guns come with either 60, 90, 120, 180 or 0 degrees phasing. 60 degrees is a common phasing for a well that will be hydraulically fractured.

The API RP 19B (replacing API RP 43 in September 2006) is the recognized standard for evaluating perforator performance. However, many perforator performance tables are still published with the older API RP 43 test data given.

The two main types of carriers are the hollow carrier and the expendable shaped charge gun. The hollow carrier holds the shaped charges in a heavy wall tube that is sealed from wellbore fluids and pressure. Most of the debris from shooting this type of gun is retrieved when the gun is pulled from the well. Sometimes expendable shaped charge guns are used. This type of gun allows a larger charge to be run than a similar OD hollow carrier gun. The charge itself is sealed from the wellbore environment. Much of the debris is left in the well and falls into the rathole on vertical wells.

Wireline pressure control equipment is run above the wellhead so that the perforating gun can be run in and out of the well when the well has pressure on it. This pressure equipment is commonly known as a lubricator. Lubricators are sized by ID and working pressure. This equipment consists of a wellhead connection, the wireline blowout preventer (BOP), the riser and the control head. It may also have full opening valves, pump in subs, tool catchers and other equipment in the run. The control head is the uppermost point of the lubricator system where the wireline enters. Well pressure is controlled with packing, pack-off rubbers, grease injection or a combination of all three. The riser section is used to allow the full wireline tool string to be raised above the wellhead valve before and after the operations.

Depth control for perforating is usually accomplished with a gamma ray/casing collar locator log. Short joints are also run in the production casing to assist in the correlation. The distance from the top shot to the casing collar locator is measured before running the perforating system into the wellbore to ensure the perforations are placed where they were intended.

Gamma ray logs measure the natural radioactivity of the formations. The gamma ray log can be recorded in open holes as well as cased holes which make it an ideal log for correlating different gamma ray signatures between wells. Nearly all gamma radiation encountered in the earth is emitted by the radioactive potassium isotope (atomic weight 40) and by the radioactive elements of the uranium and thorium series.

Some horizontal completions today are completed with an openhole system below an intermediate casing string. These wells have external casing packers that form a seal between the production casing and the formation. They also have hydraulic or ball drop actuated sliding sleeves to open successive sleeves to perform multiple fracture stimulations without the need to rig up wireline and set plugs and perforate new intervals. Perforating is not required to provide effective communication between the cased borehole and the productive formation with these types of systems.

Summary and Abstracts from Theme 2: Fracture Design and Stimulation

Summary of Presentations for Theme 2: Fracture Design and Stimulation

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Technical Presentations

The first set of technical presentations in this theme addressed geologic assessment with regard to fracture design and stimulation.

Terry Engelder, Pennsylvania State University, raised questions regarding the possibilities of fluid and gas migration or leaks into ground water through natural interconnected deep fracture systems in and around the Marcellus Shale. He assessed many parameters in his consideration of whether the physics of fluid flow at depths of 6,000 to 8,000 feet indicates the possibility of leakage of fracture fluid between the Marcellus and ground water. His conclusion is that the possibility of fracture fluid leakage from the deep Marcellus to the water table is remote. Dr. Engelder emphasized that without a pressure drive, or hydraulic head, there can be no leakage (fluid flow or leakage occurs only when fluids move from higher pressure zones to lower pressure zones).

John Williams, U.S. Geological Survey (USGS), discussed the use of well records and geophysical logs to determine the presence of fresh water, saltwater, and gas stratigraphically above the Marcellus Shale. He described three databases: USGS's National Water Information System (NWIS), the New York Department of Environmental Conservation's Water Well Database, and the New York State Museum's Empire State Oil and Gas Information System (ESOGIS). Mr. Williams discussed considerations for future drilling that would greatly expand existing information and better support assessments of fluid movement and hydraulic fracturing activities. These considerations include consistent characterization and complete reporting of fresh water, saltwater, and gas occurrence; measurement of specific conductance of water produced during drilling; geophysical logging prior to surface-casing installation; and compilation and integration of information from gas and water wells.

The second set of technical presentations addressed fracture propagation.

Tim Beard, Chesapeake Energy, discussed fracture design in horizontal wells in shale gas plays, which is a relatively new application of HF. The goal of HF in shales is to maximize the "stimulated reservoir volume" (SRV), i.e., maximizing the area of reservoir rock that is fractured, filled with proppant, and connected to the wellbore to enable maximum hydrocarbon production. Local and regional in-situ stress data and reservoir properties are required information for developing a fracture design. Typically, drilling occurs perpendicular to the maximum principal stress in the targeted reservoir. Many diagnostic tools (e.g., microseismic monitoring, tiltmeters, etc.) are used to evaluate downhole stimulation. Failure to appropriately design a given HF treatment can result in poor well stimulation and lower production potential according to Mr. Beard.

David Cramer, ConocoPhillips, discussed fracture propagation in shallow reservoirs, using an example case of a water-flooded oil reservoir in south Texas. Conditions are favorable for propagating horizontal fractures in shallow reservoirs. Treatment pressure response allows for the estimation of fracture geometry. Mr. Cramer emphasized the economic incentive for limiting fracture propagation within the target zones and described methods for controlling fracture growth.

Hal Macartney, Pioneer Natural Resources USA, Inc., discussed HF in the development of coal bed methane in the Raton Basin, Colorado. This field contains approximately 2,400 wells and produces 200 million cubic feet of gas per day from coal beds. Many of these wells have been fractured, and Mr. Macartney shared his belief that there has been no evidence of contamination to USDWs resulting from these operations. Mr. Macartney attributed this success to horizontal fracture propagation with very little height growth as seen by direct pressure measurement in open zones above the fractured coal beds, the lack of natural fractures that extend out of the coalbed target zone, sound cement and casing design, and close monitoring of fracture pressures and fluid volumes.

The third set of technical presentations in this theme addressed monitoring.

Mike Eberhard, Halliburton Energy Services, discussed the monitoring, calibration, and oversight activities that must take place during well construction, as well as before, during, and after actual HF operations. Mr. Eberhard presented images of HF sites and monitoring equipment, and described the monitoring techniques used by Halliburton. He emphasized the importance of proper well construction, as well as knowledge of rock mechanical properties and other fluid and geological conditions.

Patrick Handren, Denbury Resources, described a microseismic evaluation of wells in the Barnett Shale. He provided background information on microseismic monitoring techniques and presented case studies of two wells in the Barnett. Data from the microseismic surveys were used to calculate average SRV, fracture height, and the area covered by the fracture network. These data were then used to partially predict fluid movement from fracturing a third well. The results of this study indicate that increased well density increases the complexity of fluid movement according to Mr. Handren. In addition, while lateral fluid movement is not limited to the acreage covered by the calculated stimulated reservoir volume, Mr. Handren stated these techniques do allow for some estimate and prediction of fluid movement.

Norman Warpinski, Pinnacle–A Halliburton Service, described data and information showing that layered sedimentary sequences can restrict vertical fracture growth. This information included mineback studies, core observations, microseismic mapping, and tiltmeter data. Mr. Warpinski described how adjacent zones of significantly different stress conditions can limit the vertical growth of shallow hydraulic fractures. Mr. Warpinski concluded that hydraulic fractures consistently remain thousands of feet below ground water aquifers.

The final set of technical presentations in this theme addressed verifying zonal isolation.

Ahmed Abou-Sayed, Advantek International, discussed the complexities and quantitative uncertainties associated with fracture stimulation and design. Key uncertainties include created fracture shape and interaction with layering, faults, and other fractures. Dr. Abou-Sayed emphasized the importance of the stress field azimuth related to well orientation and fracture extent and conditions. He noted the utility of novel pressure transient test interpretations for fracture identification and concluded that multiple fractures in single wells must be well designed and require close monitoring.

Daniel Soeder, U.S. Department of Energy, National Energy Technology Laboratory, described a proposed field experiment using tracers in HF fluid. A tracer study could address two key HF issues, perception of risk and lack of field data. This type of study also could potentially provide information for other studies investigating geochemistry and fluid fate and transport. Mr. Soeder described the properties of environmental and introduced tracers and described the design and proposed locations for the proposed experiment.

Scott Cline (unaffiliated) discussed the mechanisms that affect stimulation water retention in gas-bearing shales. While fluid leak off into the fracture face and clay adsorption and swelling may account for some fluid retention, Dr. Cline believes that retention is primarily affected by capillary forces and stranding in narrow fracture branches; proppant packs and gravity may also affect fluid retention. Dr. Cline concluded that these mechanisms, combined with other aspects of HF operations and the local geology, indicate that there is a low risk of ground water contamination by HF fluids.

Summary of Discussions Following Theme 2: Fracture Design and Stimulation Presentations

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Horizontal fractures. A participant asked about horizontal fracture propagation. A presenter stated that fractures propagate horizontally due to the orientation of the stresses in the rock; the fact that fractures tend to stop moving vertically at shallow depths and move horizontally is because minimum stress is in the horizontal direction in shallow geology. A participant indicated that in general, shallower rock tends to be more plastic, while deeper rock is more brittle and easier to fracture. However, characteristics of shales do vary from formation to formation. Participants stated that both stress and rock properties affect the orientation of fractures, though participants disagreed on the relative importance of these parameters.

Natural hydraulic fractures. A participant asked for clarification on how natural hydraulic fractures occur. The presenters explained that a natural hydraulic fracture forms from gas or water. During maturation, organic matter is converted from fatty acids and lipids to kerogens, and further maturation leads to the creation of oil and gas. This reaction increases volume, which increases the pressure in the rock. If this elevated pressure exceeds the least stress in the rock (which tends to be horizontal), cracks develop in the rock. A presenter stated that these cracks will generally be densest near the source rock (the oil and gas reservoir) and noted that compressibility of gas makes gas more effective at driving cracks than water. In addition, the presenters stated that joints do not interconnect as they propagate outward, which gives the rock a low bulk permeability. Participants stated that the degree of mineralization will control conductivity more than the extent of fractures.

Lack of evidence of contamination. Several participants noted that there has been no definitive evidence of contamination in water wells from HF, based on monitoring results before and after drilling.

Availability of downhole data. A participant asked whether any downhole data are available for rock properties in the Marcellus Shale. A presenter responded that while most of this information is proprietary, some available horizontal Fullbore Formation MicroImager (FMI) results provide subsurface joint information in the Marcellus. According to the presenter, data from the Haynesville Shale suggest a different stress field orientation at the time of joint propagation.

Depth of water wells. A participant asked about the quality of data on water well depths. Another participant responded that, in general, water well depth data are very good, while data on depth to water may be less reliable. The presenter indicated that well depths are generally obtained from drilling records.

Chemical indicators of contamination. A participant asked about the chemical most likely to indicate ground water contamination from a HF treatment. Participants responded that the answer would depend on the fluid system in use, as well as local hydrogeologic processes. In most cases, however, some participants suggested that the most useful indicator might be potassium chloride. Potassium chloride may be found in the base fluid used in fracturing treatments. According to the participants, potassium chloride generally is not present in shallow ground water so it can could be used as an indicator. A few participants expressed skepticism that unique tracers could be assigned to drilling companies or individual HF jobs.

Microseismic surveys. Many of the data points in the tiltmeter study presented by Norm Warpinski represent relatively shallow (≤ 2,000 ft) layers because these are areas that receive more monitoring. A participant noted that microseismic data do not indicate which areas have received proppant. Another participant asked about the limitations of microseismic monitoring in very shallow layers. Microseismic arrays are able to capture activity that takes place above the array (usually placed at 400–1,000 ft). However, most of the time, the fracture stops in the middle of the array. A participant claimed that microseismic monitoring would be able to identify a shallow fault, but only if it were activated by the fracturing.

Participants also discussed the uncertainty in microseismic data for measuring fracture extent (length and height) and orientation. This depends on several factors, but in ideal settings the vertical and horizontal uncertainties can be as small as 20–25 ft for length and 10–15 ft for height, according to one participant. The largest uncertainty is the angle or orientation of the fracture (~3–4^{o}). Participants also discussed shear and tensile fracturing. While some hydraulic fractures are tensile fractures, a participant indicated that microseismic monitoring detects mainly shear events. One participant noted that these shear events may not always begin closest to the wellbore and move outward. Other participants noted that all producing reservoirs are naturally microseismically active. However, a few participants stated that microseismic monitoring provides an accurate picture of the stress changes in the formation.

A participant asked about using microseismic surveys to plan well placement. One participant described a microseismic program that ran for two years, spanning 20 wells and 30,000 acres. The participant noted that well interaction does not seem to substantially affect production. In this case, wells that were “watered out” (where water production dominates over gas production) eventually did as well as or better than before in terms of gas production. The participant concluded that the fracture interaction increases the fracture matrix feeding into all of the wells.

Fracture height growth. A participant asked if the Tully Limestone acts as an upper barrier to fractures in the Marcellus Shale. Another participant responded that generally this is not the case, because the Tully is fairly thin. A participant suggested that the Tully might act as a barrier if it were thicker. Another participant stated that the Onondaga Formation, which underlies the Marcellus, does act as a barrier. A participant asked about the relationship between fracture height growth and the low rate of return of fracturing fluid in the Marcellus Shale. Participants suggested that low water recovery is common (and preferred) in the Marcellus due to greater fracture complexity; the volume of the stimulated reservoir increases with increasing fracture complexity, rather than length of the fractures, allowing a greater volume of gas to move into the fractures. Participants indicated that the water recovery rate is affected by capillary trapping and the thickness of the reservoir formation. A participant noted that fluid movement must be driven by a pressure differential and is impeded by impermeable zones in the subsurface.

Public opinion and HF tracer studies. A participant asked if the proposed tracer test would be likely to satisfy all concerned parties. The presenter clarified that the tracer study should be able to satisfy all parties with regard to accuracy of results although those results may only apply to the study location. The presenter noted that one study in one location cannot be used to draw conclusions about other areas, but this study would be a first step. A participant noted that 20 years of EPA and other studies have been unable to alleviate the public’s mistrust of Class I Underground Injection Control (UIC) wells. Another participant stated that some people in New York State are looking to the EPA’s current study as a definitive determination on the safety of HF.

Pumping tests. A participant called attention to a graph used in Mr. Cline’s presentation (on slide 10) that showed pumping pressure over time during a HF treatment. The participant noted that, as shown in the graph, a formation integrity test (FIT) is not the same as a leakoff test (LOT). The participant added that fracture closure pressure (FCP) is the closest value to the least principal stress.

Fracture complexity. A participant asked about how fracture models account for fracture complexity, since fracture models appear to describe a single fracture that propagates outward. A participant stated that while multiple or branching fractures do occur, points of weakness in the formation control which fractures will dominate in growth. According to the participant, all of the fracture branches will grow simultaneously, and longer fractures require less pressure to propagate further. One participant added that fracture activity in naturally fractured reservoirs is different from fracture activity in homogeneous, less fractured formations.

Shallow fracturing. A participant asked about the shallowest fracturing in the Marcellus Shale. There was one HF test in Otsego County, NY at 2,000 ft deep. However, this was not a large volume slickwater HF job, and activities were discontinued after the test. Participants described current and past shallow HF operations in other parts of the country. These locations included Alaska, where fracturing for a UIC Class I well took place at the base of permafrost (approximately 2,000 ft); the Huron Shale near the West Virginia/Kentucky border; and Oak Ridge National Lab in Tennessee, where, according to one participant, uncased monitoring wells became a conduit for fluid movement and led to contamination. A participant added his understanding that New York is planning to limit large volume HF operations to a depth of 2,000 ft or deeper (or 1,000 ft below ground water supplies, where applicable).

Abstracts for Theme 2: Fracture Design and Stimulation

Abstracts were submitted to U.S. EPA by the presenters for use in this proceedings document. Not all presenters submitted abstracts of their presentations.

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The Distribution of Natural Fractures above a Gas Shale: Questions about Whether Deep Fracture Fluid Leaks into Groundwater Outside the Realm of Faulty Borehole Construction

Terry Engelder
The Pennsylvania State University

Extended Abstract

One concern about production of shale gas is the possibility of hydraulic fracture fluid leaking upward along an interconnected network of fractures to contaminate groundwater. In the Appalachian Basin, isotopic studies of stray methane provide unambiguous evidence for leakage from gas storage fields through the Marcellus gas shale and into groundwater. The question is whether this is a case of faulty borehole construction where methane is leaking along poor cement jobs outside of casing or whether this is a case of methane traveling toward the water table along natural pathways, most likely consisting of unhealed faults or fractures. Elsewhere in the Marcellus gas fields, preliminary data isotopic studies by the Pennsylvania Department of Environmental Protection (PA DEP) indicate that thermogenic methane comes from Upper Devonian sands that are not immediately charged by gas from the Marcellus. While migration of natural gas is common, particularly at shallow depths, the migration of deep fracture fluid remains undetected in the Appalachian Basin. The question is whether the physics of fluid flow at depths of 6000' to 8000' permits leakage of fracture fluid between the Marcellus and groundwater with a probability that should concern the public. A back-of-the-envelope analysis suggests that the physics of the Earth reduces the probably of leakage to a level where the risk should be acceptable to a nation that consumes natural gas at the rate of nearly 25 trillion cubic feet (Tcf) per year.

If leakage occurs outside the realm of faulty borehole construction, unhealed fractures are the most likely pathway. The plausibility of rapid leakage along fractures depends on evidence for the pervasive development of interconnected fractures between gas shales (> 6,000 feet) and fresh groundwater (< 1,000 feet). Although continuous fracture imaging in the borehole might aid in sorting out whether fractures are interconnected from depth to the surface, borehole coverage may be insufficient for a conclusive answer. This leaves outcrop mapping as the other means of direct observation to resolve the extent of fracture interconnectivity.

For this discussion, natural fractures fall into either of two failure classes: shear failure leading to faults and tensile failure leading to macroscopic cracks called joints. Faults grow during direct shear failure under unusually high stress or grow as reactivated joints and bedding planes. Joints propagate within a spectrum failure conditions depending on their crack driving stress. If propagation takes place at depth under high fluid pressure working against crack normal

compressive stress, the joint is a natural hydraulic fracture. If propagation takes place in the near surface under relaxation stresses accompanying exhumation, the joint is an exhumation-related fracture. Natural hydraulic fractures and exhumation-related fractures are end members of a spectrum that may include fold-related jointing where both pore pressure and bed-parallel stretching lead to an effective stress state favoring propagation.

Outcrop observation is only effective to the extent that the operator has a strategy for distinguishing between deep-formed fractures and exhumation-related surface fractures. The most common fractures in a gas shale are the natural hydraulic fractures which occur in a plume emanating from the gas shale but rapidly dissipating above gas shale. Exhumation-related fractures have a much different morphology and are easily distinguished from NHF. A plume-like distribution of joints above gas shales of the Appalachian Basin is consistent with fluid-drive propagation mechanism where high pressure fluid bubbles from gas shales as a consequence of thermal maturation but rapidly looses pressure as it migrates up section. The implication is that fractures driven by fluid pressure are not uniformly distributed up to the surface but rather are concentrated near the top of gas shale.

Distribution of Natural Fractures

It is commonly assumed that if a rock contains fractures (i.e., faults, fluid-driven joints, and exhumation-related joints), they are a natural pathway for contamination of ground water. Outcrops are often densely populated with fractures and it is assumed that rocks in the subsurface look the same way throughout the 6000' to 8000' of overburden above a gas shale such as the Marcellus. In fact, many joints in outcrop are exhumation-related fractures that propagate in the near surface and are not found at significant depths, (> 100s of feet). Outcrops over the Marcellus of the Appalachian Plateau portion of the Appalachian Basin consist of clastic and carbonate rocks varying in age from Devonian to Permian. Faults are exceedingly rare on scales greater than the size of tectonic wedges, particularly above the Frasnian section. Tectonic wedges are most common in large-channel sandstones where bedding slip can occur on crossbeds. Fluid-driven joints are most common in gas shales but in sections overlying these gas shales, they lack the requisite interconnectivity to be effective conduits even in the presence of a pressure drive. Without an interconnected pathway of joints, the physical principle governing the rate of leakage between the Marcellus and groundwater is the equation for fluid flow in porous media, Darcy's Law.

Darcy's Law

The rate of fracture fluid leaking into ground water by flow through the overburden between the Marcellus and near surface rocks is understood using Darcy's Law. Although flow along natural pathways including joints and faults may be more appropriately represented by parallel plate flow, lack of interconnectivity of these joints and faults means that Darcy's Law is the better model for flow in the bulk rock. Fluid flow ($\boldsymbol{Q}$) in a porous media can occur only if a pressure drop ($\boldsymbol{P_a - P_b}$) (i.e., a differential hydraulic head) develops between two points with the entrance point (i.e., fracture fluid in the Marcellus) being at a higher hydraulic head than the exit point (i.e., fresh groundwater). The rate of fluid flow is governed by the magnitude of the pressure drop. The relationship between rate of flow and pressure drop is expressed in an equation with four variables including the viscosity of the fluid (***μ***), the permeability of the rock (***k***), the length of the flow path (***L***), and the cross section of the flow (***A***). Of course, the rate of flow approaches zero if the permeability, cross section, and pressure drive become very small or viscosity and flow path length become very large.

$$Q = \frac{-kA}{\mu L}\left(P_a - P_b\right)$$

Path Length (L)

The least ambiguous variable in Darcy's Law is the length of the flow path. All else being equal, the rate of leakage of fracture fluid from deep (6000' to 8000') gas shales of the Appalachian Basin is as much as four to five times less than leakage of fracture fluid from conventional gas reservoirs stimulated at a depth of 1500', for example, in the Pavilion gas field of Wyoming.

Pressure Drive (P_a – P_b)

Leakage of fracture fluid will take place only if pressure drive is present and sustained for a period long enough to drive fluid from the Marcellus to groundwater. There are three major sources for a pressure drive: pressure during wellbore stimulation, a topographic pressure drive, and maturation-related abnormal pressure. A pressure drive is the most critical part of Darcy's Law in terms of risk to groundwater.

Maturation-Related Pressure Drive (P_a – P_b)

While it might be argued that overpressure gas also creates a pressure drive from the Marcellus to groundwater, this pressure drive was incapable of draining the Marcellus gas shale over periods of as much as 260 million years ago (Ma). If fracture fluid is injected into the gas and maintained at gas pressure, the gas and water would separate with the gas making its way to the top of the pressurized column. Theoretically the top of the pressurized gas-water could drive its way to groundwater. Long before the column with gas on top got to groundwater, the column would have broken into a hydrostatically pressurized regime. Such break through would immediately relax the pressure drive and flow would stop long before fracture fluid was driven upward to place groundwater at risk. The probability of a sustained maturation-related pressure drive causing groundwater contamination is very, very low.

Regional Flow (L) and Hydrodynamic Pressure Drive (P_a – P_b)

One natural pressure drive arises from topographically-driven hydrodynamic flow. Hydrodynamic flow is driven by the pressure drop between groundwater under topographic highs and ground water under topographic lows. The depth of penetration for hydrodynamic flow is largely governed the geometry of the most permeable units but an important secondary governor is the lateral distance between source (topographic high) and sink (topographic low) and the vertical distance of flow as governed by topography. The largest volume of underground flow is short circuited by local topography where depth of penetration is less than the topography. Some groundwater is driven deeper in the section and flows further out into the basin from topographic highs. In this latter case, the volume of flow is less and the time of flow between source and sink is commensurately longer. In the Appalachian Basin, penetration to the Marcellus at 7000' is nearly an order of magnitude greater than the local topography. Modeling suggests that penetration to 7000' from a 300' topography drive has a time constant of 100,000 years or longer. This means that the probability of regional flow leading to a leakage up and into groundwater is remote on time scales that really matter to the EPA debate about hydraulic fracturing. Because there is no indication from the Appalachian Basin that such long wave-length flow paths upset the density stratification of the basin, the probability of a topographic drive causing leakage between Marcellus and groundwater is again very, very low.

Density Stratification Reduces Effectiveness of Natural Pressure Drives (P_a – P_b)

Within the Appalachian Basin, groundwater is stratified by density. Freshwater is found from the top of the water table to depths of as much as 1000 feet. Below the freshwater layer, groundwater becomes progressively more saline with waters in the vicinity of the Marcellus approaching oil field brines. This high salinity may have developed by very long term (1-10 million years) groundwater circulation down section to the Silurian Salina Formation which is salt rich. In a one-dimensional flow model density stratification is stable without the possibility of a pressure drive to upset this stability. Flow between fracture fluid in the Marcellus and fresh groundwater would upset this density stratification. In the hundreds of thousands of water wells drilled in the state of Pennsylvania there is no evidence of fresh water wells gradually becoming saline, the only sign that a pressure drive associated with 50 years of hydraulic fracturing in PA has upset the regional density stratification. Density stratification indicates that rate of regional flow carrying fracture fluid to groundwater is very, very low.

Pressure Drive Reduction Upon Flowback (P_a – P_b)

Flowback immediately following well stimulation relieves any pressure drive that was momentarily developed between fracture fluid that is injected into the deep Marcellus and the layer of fresh groundwater at depths of less than 1000 feet. Without a pressure drive there can be no direct leakage between fracture fluid in the Marcellus and groundwater several thousand feet above. Any man-made pressure drive during hydraulic fracture stimulation is not held in place long enough to put groundwater at risk.

Distribution of Stimulated Fractures (k)

Recent studies indicate that stimulation may extend laterally as much as 2000 feet from the borehole (Mayerhofer – Pinnacle) and as much as 1000 feet above the borehole (Fisher - Pinnacle). In the Marcellus this leaves as much as 6000 feet between unstimulated rock and groundwater. This thickness of rock would be exceedingly difficult for fracture fluid to penetrate without large and sustained pressure drive which, of course, is lost with the onset of flowback after maximum of 1000 feet of penetration.

The Inward Pressure Drive by Gas Depletion (Pa – Pb)

Once gas production starts, reservoir pressure drops. If a pressure drive develops subsequent to the initiation of production, the pressure drive will cause flow from the rock formation and into the Marcellus reservoir. For fracture fluid at the extremes of stimulated fractures, flow is back along the fractures and into the production tubing.

Thermal Maturation (k)

The Marcellus reached maximum thermal maturation about the Middle Permian (260 Ma). At that time, generation was sufficiently rapid to cause the development of overpressure (> 0.7 psi/ft) and in some cases the high pressures drove natural hydraulic fractures. Exhumation and thermal cooling commenced with the onset of rifting in the Triassic (perhaps 220 Ma). Despite exhumation, much of the northern Appalachian Basin still holds overpressured gas. Even with a network of natural fractures, the Marcellus has not leaked a sufficient quantity of gas to reach a hydrostatic pressure. In fact, joints in shale are so planar that, when pressed together under confining stress, these joints fail to provide a sufficiently larger permeability over the matrix permeability to permit economic gas production without propping using sand of 100 mesh or less. Apparently, gas pressures in natural hydraulic fractures don't prop these joints sufficiently to enhance bulk permeability despite the presence of overpressures.

Permeability of Black Shale (k)

Black shales including the Marcellus are seal-quality rocks with a permeability of 100 to 500 nanodarcies. A porous sandstone can have a permeability of a darcy (9.8×10^{-13} m^2). Because permeability is found in the numerator of Darcy's law, lower permeabilities lead to reduced flow rates which means that shale matrix will not serve as a path for leakage of fracture fluid.

Permeability of Joints (k)

Laboratory experiments show that joints unfilled by any mineralization are permeable relative to rock matrix. However, in order to affect the bulk permeability of the rock, these open joints have to interconnect. Otherwise, the bulk permeability of the rock is close to the matrix permeability. In the Appalachian Basin interconnected joints are common in gas shales like the Marcellus. The population of interconnected joints trails off with distance above gas shale and groundwater. While the presence of joints allow the possibility of fracture fluid leakage as long as the joints are propped open, lack of connectivity reduces the bulk permeability of the overburden to that of the intact rock.

Permeability of Faults (k)

In oil basins, faults are some of the most effective seal rocks, much less permeable than matrix sandstone. This is particularly true for faults that cut shales where the clay smear mechanism may render a fault gouge that is less permeable than the progenitor shale. Faults leak after earthquake-related slip but in an area that is not prone to earthquakes as is the case for the Appalachian Basin, faults are rarely open conduits. Flexural slip folding causes bedding slip surfaces that are coated with fibers known as slickelites which have virtually no permeability.

Viscosity of Fluid within the Black Shale (μ)

Black shales including the Marcellus are very impermeable rocks relative to many other lithologies. Commonly, the permeability is on the order of 100 to 500 nanodarcies. This means that a low viscosity fluid such as natural gas is held in place for considerable lengths of time. Because viscosity is found in the denominator of Darcy's law, increasing the viscosity of actively moving fluid would reduce the flow rate. Injection of a high viscosity hydraulic fracture water with additives just makes a good seal all that more effective. A rock that has not leaked natural gas in geological time is unlikely to leak a more viscous fracture fluid on an anthropomorphic time scale.

Capillary Forces (k)

Capillary forces are inversely proportional to the size of pore throats in a water-wet shale. To the extent that fracture fluid converts gas shale to a water-wet rock, capillary forces may become important in reducing leakage from gas shale.

Unknown Effects

In a fully developed section, enough water is injected to cause a regional extension of 1% in the direction of the maximum horizontal stress at the depth of the Marcellus. A strain discontinuity will develop at the top of the layer of injection. The effect of this strain discontinuity of regional permeability patterns is unknown but a strain discontinuity seems unlikely to affect the nature of the section over the stimulated zone.

Conclusion

I have identified at least 16 parameters that govern potential leakage of fracture fluid between the Marcellus and groundwater. Most parameters favor the protection of groundwater. In assessing risk to each parameter, the overall risk is the product of each multiplied serially. The sixteen parameters together make a powerful case that leakage of fracture fluid from the deep Marcellus to the water table is remote. This conclusion is consistent with the 2009 Groundwater Protection Council study.

Evaluation of Well Records and Geophysical Logs for Determining the Presence of Freshwater, Saltwater, and Gas above the Marcellus Shale, South-Central New York

John H. Williams
U. S. Geological Survey

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.

Records of water wells in the National Water Information System (NWIS) and records and geophysical logs of gas wells in the Empire State Oil and Gas Information System (ESOGIS) were evaluated to provide a preliminary determination of the presence of freshwater, saltwater, and gas above the Marcellus Shale in south-central New York. This work expands the geographic extent of the well-record evaluation of Williams (2011) that included Chemung, Tioga, and Broome Counties to include Cortland, Chenango, Otsego, and Delaware Counties (fig. 1). In total, these counties form the core of the Marcellus and Utica shale-gas fairway in New York.

Water-well records stored in the NWIS, which is maintained by the New York Water Science Center of the U. S. Geological Survey (USGS), were retrieved for the 7-county study area online from http://waterdata.usgs.gov/nwis/inventory. The NWIS contains records for nearly 4,000 water wells in the study area. Many of the water wells recorded in the NWIS and almost all of the 65 sites at which saltwater and (or) gas zones were penetrated were inventoried as part of glacial-drift aquifer investigations in the 1960s and 1970s (Randall, 1972; MacNish and Randall, 1982; Randall and others, 1988). These investigations were focused on the glaciated valleys of the Susquehanna and Chemung Rivers in New York. The presence of saltwater in water wells was reported by drillers or well owners based on taste tests, or was determined by water-quality analyses that indicated a chloride concentration of greater than 250 mg/L. The presence of gas was reported by drillers or well owners or was observed during field inventory.

Gas-well records and geophysical logs stored in the ESOGIS, which is maintained by the Reservoir Characterization Group at the New York State Museum (NYSM), were retrieved for the 7-county study area online from http://esogis.nysm.nysed.gov/. The ESOGIS contains records for about 600 gas wells in the study area. The gas-well records in the ESOGIS are for single- and multiple-well sites, wells whose confidential status had not expired (typically 2 years), and permitted but uncompleted wells. The density of the gas-well distribution generally decreases in a northeast direction across the study area from more than 200 wells in Chemung County to less than 20 wells in Otsego County. Because the formations above the Marcellus Shale generally have not been the focus of gas exploration, many of the gas-well records contain little or no information on the stratigraphic interval of interest. Penetration of water and (or) gas zones above the Marcellus Shale was reported for 112 gas-well sites. Water flows were reported by gas-well drillers as freshwater or saltwater presumably based on taste tests. Water flows commonly were rated by the gas-well drillers in inches of the stream discharging from an open pipe into a mud pit while drilling with air. Reportedly, a 1-inch stream roughly equates to a flow of 10 to 20 gal/min, and a 2-inch stream roughly equates to a flow of 40 to 50 gal/min. Gas-flow rates generally were not quantified; those that were rated were reported in MCF (1,000 cubic feet), which presumably equates to the flow rate per day.

Geophysical logs for 150 gas wells in the study area are stored in the ESOGIS in Log Ascii Standard (LAS) format. No geophysical logs were collected prior to the installation of steel surface casing, which typically is set to a depth of 500 to 1000 feet below land surface. Most of the log suites did include gamma measurements from the bottom of the well to near land surface. Neutron porosity and density logs were commonly collected along with the gamma logs. Only a few temperature, focused resistivity, or induction logs and no fluid resistivity logs were available for the interval above the Marcellus Shale. Again, because the formations above the Marcellus Shale generally have not been the focus of gas exploration, limited geophysical logging has been completed on this stratigraphic interval.

The well records and geophysical logs were reviewed to obtain information on well completions, geologic formations penetrated by the wells, and the presence of freshwater, saltwater, and gas above the Marcellus Shale in the study area. The spatial and stratigraphic distributions of freshwater, saltwater, and gas above the Marcellus Shale were investigated. To aid in the evaluation, Geographic Information System (GIS) coverages and histograms of the well data were created with ESRI ArcGIS software; and geophysical log composites were created with WellCad software.

The evaluation of the well records and geophysical logs provide a preliminary but incomplete determination of freshwater, saltwater, and gas above the Marcellus Shale in the study area (Figure 1). The evaluation indicates that freshwater aquifer zones are log-normally distributed with depth and that freshwater circulates to a greater depth in the uplands than in the valleys. The base of the freshwater aquifer appears to be about 850 ft below land surface in upland settings but only about 300 ft below land surface in valley settings. At depths greater than 300 ft in valley settings, groundwater in the Upper Devonian bedrock, and in a few areas in the glacial drift, is salty. Williams and others (1998) found saltwater at similar depths in the glacial drift and Upper Devonian bedrock during an inventory of water wells in the glaciated valleys of Bradford, Tioga, and Potter Counties across the border in Pennsylvania. Water-quality analyses from these wells indicated that the shallow saltwater is characterized by elevated concentrations of chloride, barium, strontium, and radium and low concentrations of sulfate.

Gas is present locally in the glacial drift, Upper Devonian bedrock, Tully Limestone, and Hamilton Group above the Marcellus Shale. The frequency of gas zones in the Upper Devonian bedrock generally increases with depth. The highest rates of gas flow above the Marcellus Shale appear to be associated with the Tully Limestone. Pockets of gas are locally present above the base of the freshwater aquifer with gas and freshwater occurring in close vertical proximity (Figure 2). Reported gas shows from targeted zones below the Marcellus Shale were correlated with distinct cooling anomalies on temperature logs suggesting that such logs could be an effective tool for delineating gas above the Marcellus if available.

Consistent and complete reporting of freshwater, saltwater, and gas during the drilling of future Marcellus and Utica shale-gas wells would greatly expand existing information. Field measurement of specific conductance of water produced during drilling would enhance the quantitative value of the gas-well records. Consideration should be given for a two-phase open-hole logging program that includes collection of caliper, induction, fluid resistivity, and temperature logs in addition to nuclear logs for the depth interval above the Marcellus. In such a program, the uppermost part of the well would need to be logged prior to the installation of surface casing. Compilation and integration of information from gas wells and from water wells that are inventoried and water-quality sampled during gas development and ongoing county- and basin-wide programs (Hetcher-Aguila, 2005; Hetcher-Aguila and Eckhardt, 2006; Nystrom, 2007; and Nystrom, 2008) would provide an important database for understanding and protecting the freshwater aquifers in the Marcellus and Utica shale-gas fairway.

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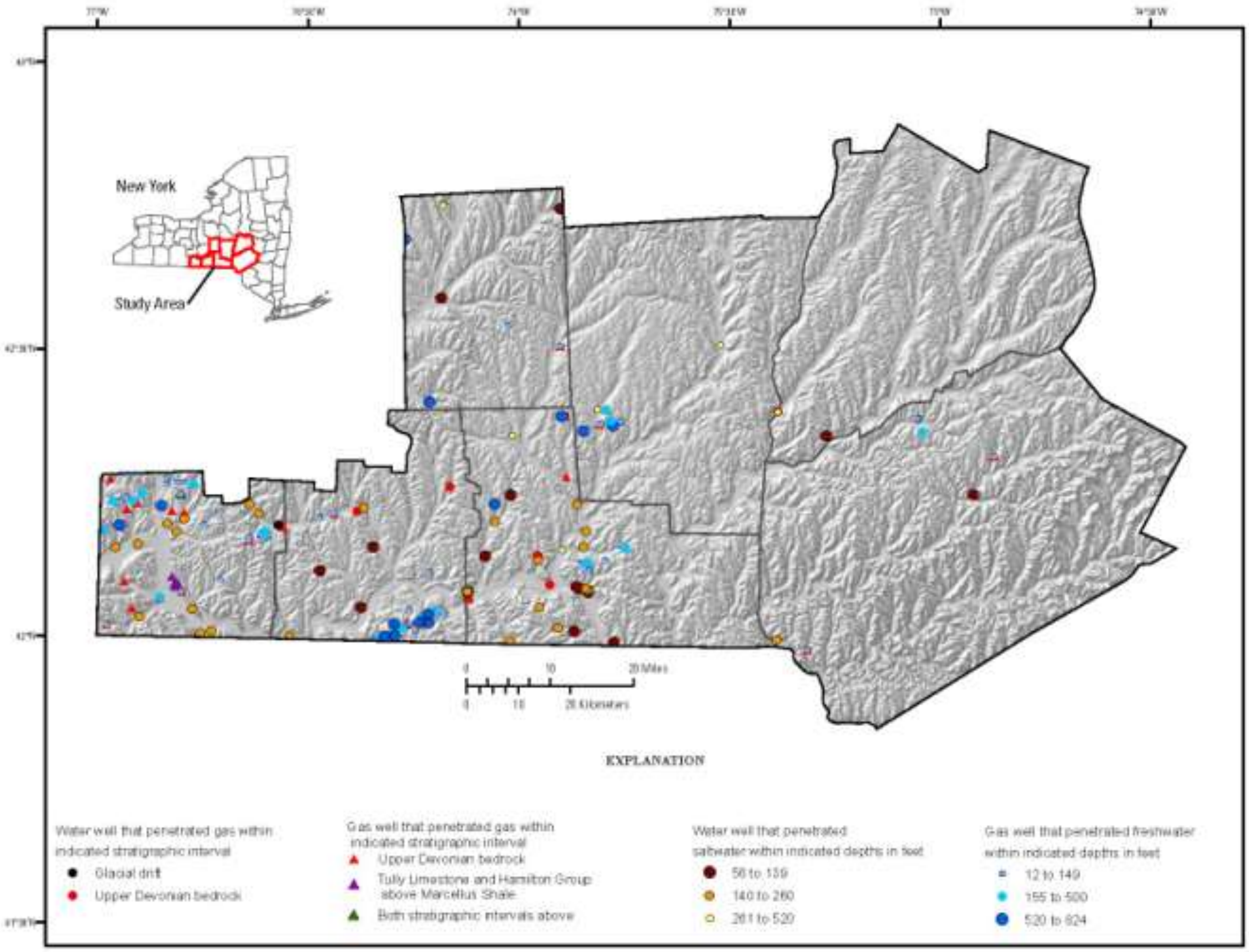

Figure 1. Location of study area in south-central New York, water wells that penetrated saltwater and (or) gas, and gas wells that penetrated freshwater and (or) gas above the Marcellus Shale

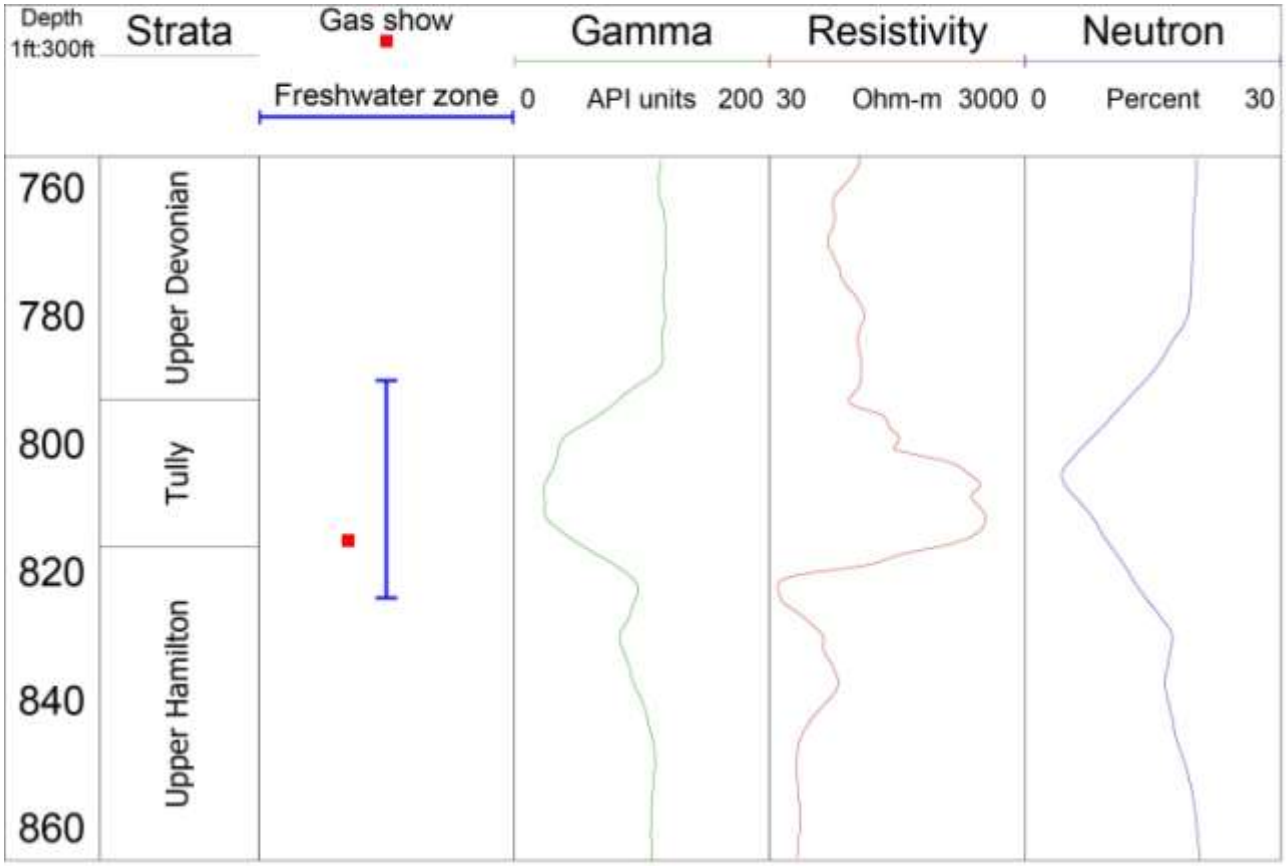

Figure 2. Geophysical logs and reported freshwater zone and gas show for the 760-860 ft depth interval in gas well 19484, Cortland County, New York

Fracture Design in Horizontal Shale Wells – Data Gathering to Implementation

Tim Beard
Chesapeake Energy Corporation

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.

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.

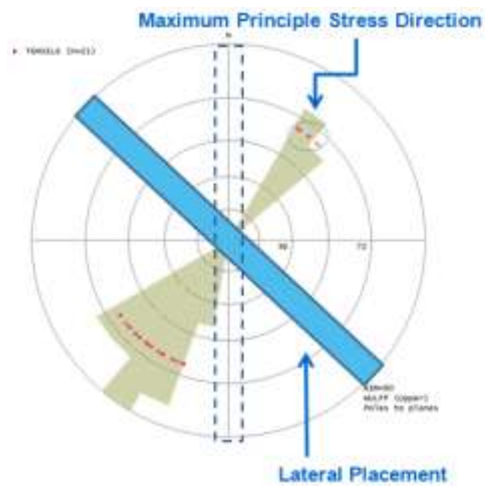

Figure 3

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 ν_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 $((E_h/(1-\nu_h^2))\varepsilon_{hmin} + (E_h\nu_h/(1-\nu_h^2))\varepsilon_{hmax})$. 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.

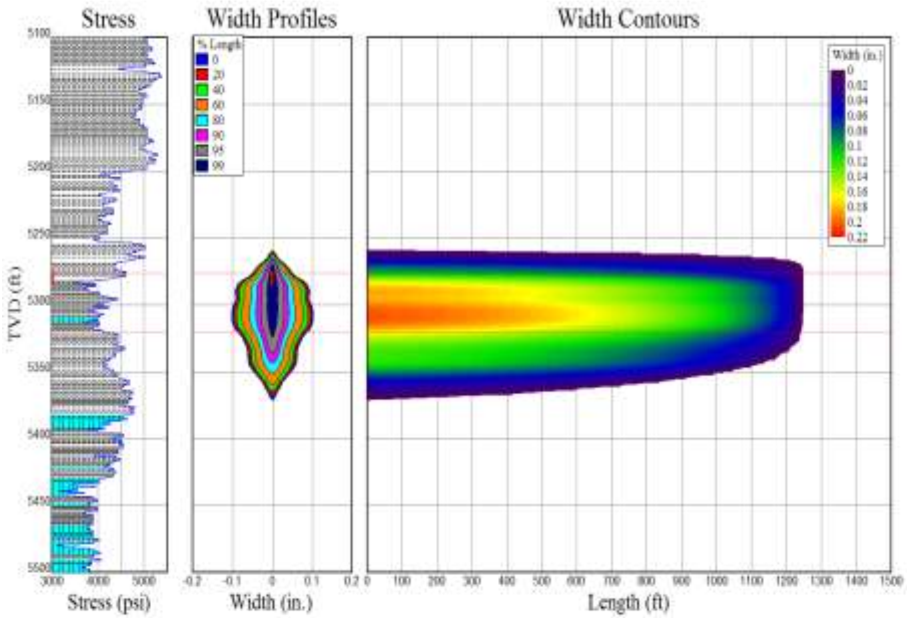

Figure 4

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.

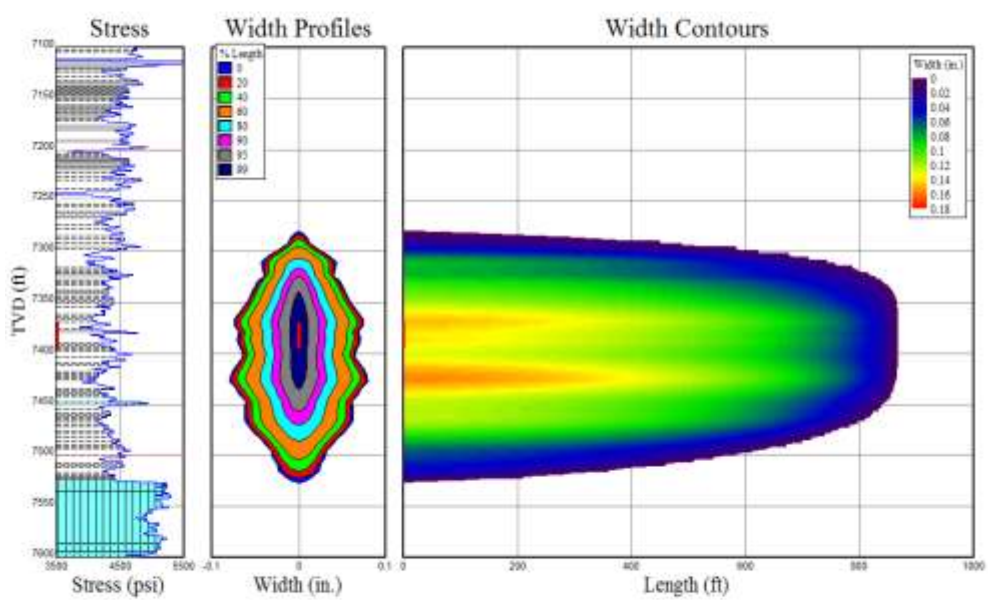

Figure 5

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.

Hydraulic Fracturing in Coal Bed Methane Development, Raton Basin, Southern Colorado, USA

Hal Macartney
Pioneer Natural Resources USA, Inc.

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.

Pioneer Natural Resources USA, Inc. operates a natural gas field in the Colorado portion of the Raton Basin, a field containing approximately 2400 wells and producing 200 million cubic feet of gas per day from coal beds. Many of these wells were hydraulically fractured by Pioneer's own personnel and equipment. There have been no instances of damage to underground sources of drinking water from these operations, and no more than 20' of height growth in induced fractures.

The Raton Basin is located between the Rocky Mountains and the high plains to the east, and it straddles the Colorado-New Mexico state line. The target formations for coal bed methane are the Tertiary-aged Raton and Cretaceous-aged Vermejo, both characterized by intermittent thin coals, sands, silts and shales. Both of these formations are at the surface in portions of the basin. Naturally occurring gas seeps are common, and coal is actively mined for industrial consumption.

Pioneer's coal bed wells are vertical and produce from depths from 450' to 3500', and from as many as 20 coal seams varying from 1'-8' in thickness. Coals are hydraulically fractured in stages using a coiled tubing tool which enables multiple stimulations in one hole-entry. Cased boreholes are pre-perforated in all the target coals and stimulation proceeds up from the lowest, with each zone isolated for its treatment.

Pressures are closely monitored during the frac in three critical areas:

1. In the tubing delivering the fluids and pressure to the frac tool
2. In the open space above the frac tool, inside the casing
3. In the well-head at the surface, outside casing and inside surface casing

Tubing pressure(1) indicates the delivered pressure to the rock underground and is used to gauge job performance in breaking down the formation and delivering fluid and sand into it. Casing pressure (2) monitors any fluid communication from the treatment zone to open perforations above the top packer; any such pressures terminate pumping.
The well-head pressure (3) indicates if any fluid or pressure has migrated behind casing to the surface.

The casing pressure(2), gives us practical and unequivocal evidence of how high our fractures are growing; perforated zones that are too close will communicate. From experience, 20' is the safe margin for interval spacing and therefore the upper limit of height growth. It is estimated from performance, volumetrics, and computer models, that our lateral fracture growth is from 120-200'.

In a typical hydraulic fracture stage will use 150 barrels (6300 gallons) of foamed fluid, consisting of 70% nitrogen, 30% water (recycled water produced from coal bed wells), 60lbs. of a natural guar gelling compound, 4 gallons of an organic enzyme to break down the gel, and 15 gallons of a mild detergent to create foam. Around 8000 lbs. of sand proppant is placed for every foot of coal stimulated.

Analysis of data from 2273 Pioneer frac jobs since late 2001 shows that more than 12,000 individual hydraulic fracture stages were executed. Of these, approximately 10% were interrupted before the end of the pumping because of high pressures (inability to initiate or finish pumping sand), materials or mechanical difficulties, or because of pressure loss. These last events have dropped to near zero in recent years with broader interval selection.
To date, with more than 12,000 stages pumped, there have been no instances where Pioneer's hydraulic fracture fluids or pressures impacted underground sources of drinking water. This is due to a number of factors. Mechanically, the fractures propagate horizontally with very little height growth and frac volumes and energy rapidly dissipate in the formation. Geologically, the coals and sands are discontinuous and lack through-going natural fractures. Operationally, real-time monitoring of frac pressures and fluid volumes informs us of out-of-zone loss and results in early shut-in. Finally, there is a competent seal all the way to surface provided by cement and casing.

Pioneer continues to model and improve its hydraulic fracture processes, applying experiences gained in the Raton Basin to its operations in other active plays.

Fracture Design and Stimulation –Monitoring

Mike Eberhard
Halliburton Energy Services

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DC01:570405.2* This abstract provides a general overview only and is applicable to a majority of the hydraulic fracturing treatments currently being pumped. It is not intended to address all situations/scenarios that may occur.

As the previous sections have shown there is considerable work that goes on before a fracture treatment is pumped. Two points that bear repeating concern (1) the importance of proper well construction and (2) the availability of information about conditions to be expected during the treatment. It is through the well construction process that drinking water aquifers are protected, producing formations are isolated, casing is protected from corrosive fluids, etc. In addition, since the fracture treatment is carefully designed beforehand and expected pressures and other parameters are established, the casing and tubulars will have been designed to handle the treatment and subsequent well production without compromising the integrity of the well.

There has also been discussion about what goes into the design of a hydraulic fracture treatment, *i.e.*, knowledge of the mechanical rock properties of the formation to be treated as well as adjacent bounding layers, reservoir properties of the target formation, information about the fluid systems to be used and how the formation will interact with these fluids. From this information the operator and pumping service company can set up the hydraulic fracture treatment and know what will be pumped, what equipment will be required, and what is to be expected during the actual treatment.

What Do You Need to Know before Showing up on Location

The first step in setting up a fracture treatment job is to know the expected treatment rate and pressures. These two parameters are based on several factors discussed more thoroughly within this workshop, but for this section it is important to note that they are calculable. For a given formation there is a pressure which when applied will cause the rock to fracture. This pressure is often referred to in terms of a gradient (fracture gradient - fg). Knowing the fracture gradient, the actual bottom hole treating pressure (BHTP) required to fracture the rock can be calculated for a given depth:

BHTP = fg * depth + excess pressure .... (1)

In this equation excess pressure is the additional pressure required to extend a hydraulic fracture; *i.e.*, net extension pressure, process zones stress, etc. These excess pressures are typically significantly lower than the pressure required to fracture the rock.

Once the BHTP is known then an expected wellhead treating pressure (WHTP) can be calculated by accounting for additional pressures that occur while treating a well:

$WHTP = BHTP + P_{pipe} + P_{perf} - P_{hyd}$ .... (2)

In this equation P_{pipe} is the friction pressure resistant to flow down the wellbore during pumping operations and is fluid and rate dependent; P_{perf} is the pressure drop across the perforations; and P_{hyd} is the hydrostatic pressure of the fluid in the wellbore and is also fluid dependent.

Once the expected BHTP and WHTP are determined, the proper casing string or tubular configuration can be designed to handle the pressures experienced while treating the formation. The WHTP is also used to calculate the hydraulic horsepower (number of trucks; HHP) required to pump the job at the desired treatment rate from the following equation:

$HHP = (WHTP * Rate) / 40.8$ .... (3)

The next step in setting up a job is to know what will be pumped, *e.g.*, the additives required and the rates at which the additives are to be used, proppant type and volume, etc. For some jobs this requires pre-job testing to determine whether the fluid system intended for use in the fracture treatment is compatible with the base fluid being supplied on location. This is an important step since it also establishes what will be required for the fluid system to perform as desired. Once this information is known then a final treatment design is determined and communicated to the field location for execution. This information is then put together in tabular form, giving the operator and service company a ready guide for setting up the job. An example of a typical pump schedule is included in the appendix.

Rigging Up the Pumping and Monitoring Equipment

The care that is taken in designing a fracture treatment job carries over to the implementation of the job, beginning with the set-up for the job. After the equipment, personnel, and materials are on location a safety meeting is held. During this safety meeting items such as well site concerns, proper PPE, rig-up concerns, etc. are reviewed to ensure that appropriate steps are being taken to ensure safety on the job site. The time it takes to rig up the pumping equipment and surface treating lines can vary from a couple of hours to a couple of days depending on the treatment. During this time there is also quality control work going on to ensure that the fracturing fluid will perform as expected and that the correct materials are on location in the appropriate quantities.

After all the surface equipment has been rigged up there is another safety meeting. During this safety meeting details of the job are reviewed, including the maximum WHTP, expected WHTP, pump rate, overall job schedule, who is responsible for what, etc. After the safety meeting all surface piping is pressure tested to a predetermined maximum pressure. At this time the pop-off valves on the surface lines are tested to make sure they work at the desired pressure and the pressure kick-outs on the high-pressure pumps are also tested to insure they work properly. In addition, the pumps used for liquid additives are bucket tested to ensure that they are functional and are calibrated properly. The proposed pumping schedule is loaded into the on-site computer system to assist the fracturing treatment operator in running the job as close to design as possible. While computers are capable of actually running the treatment, at this time most service companies still rely on a team in the treatment van to control the actual fracturing treatment with the assistance of the computers.

Pumping the Treatment

Once everything has been calibrated and pressure tested there is generally one last review between the operator's representative and service company representative to go over the treatment parameters. Once everyone is in agreement, the wellhead is opened up and the high pressure pumps are brought on line. At this time fluid is being pumped down the wellbore at a slow rate as pressure starts to increase. The rate and pressure are increased to the anticipated WHTP where the formation should fracture (breakdown). This is one of the first points where the actual treatment can be calibrated to the job design. If breakdown does not occur within a reasonable pressure compared to what is expected then the treatment is shut down and possible causes are investigated.

There are several points on the surface where rates, pressures, and densities are monitored and recorded during a treatment. (A simplified location schematic showing where the different treatment monitoring occurs is provided in the appendix.) For example, highly accurate transducers are placed at several different locations in the surface lines and equipment to monitor real-time pressure data, a variety of different flowmeters are used (depending on the material being metered) to record treatment rates and additive rates, and densometers are used to measure the density of the fluid being pumped downhole. Examples of some of the data being monitored and recorded include: WHTP, annular pressure, downhole slurry pump rate, clean fluid rate, wellhead proppant concentration, and individual additive rates, along with an extensive amount of mechanical information about the equipment on location. All the information from these multiple sources is collected and displayed by state-of-the-art computer systems located in treatment control vans. Most of the time, these data are transmitted using hard wires connecting the computer to the monitoring device.

It is also important to note that in addition to monitoring there are also mechanical devices which are used during a fracture treatment to provide additional safety for the wellhead. Two of these devices are pressure pop-off valves on surface lines and pressure kick-outs on the high pressure pumps.

While pumping the treatment both the operator and service company continually monitor the computer screens displaying information about the treatment as it is being pumped. The main concern is pressure. Both the operator and the service company want to make sure the maximum WHTP is not exceeded to protect the wellbore from any possible damage. (It is important to understand that it is inefficient to have to repair wellbores so every effort is made to prevent them from being damaged.) Some variations in pressure are normally seen during a fracture treatment. These variations are interpreted to determine their causes and significance; there are constant decisions being made about what the status of the treatment is and what to do as the treatment proceeds. An example of a treatment chart can be found in the appendix of this abstract.

Close attention is also paid to the annulus. In many cases the annulus is monitored with a gauge for any pressure increase in excess of normal fluid cool-down and heat-up, in other cases the annular valve is open and any fluid flow up the annulus can be seen at the wellhead and appropriate steps can be taken to address the fluid flow in the annulus.

Since any additive used in a hydraulic fracturing treatment serves a specific purpose, it is important that these additives are run at their designed concentrations. As mentioned earlier all additive rates are monitored during the treatment to insure they are run correctly. (An example of an additive rate chart is shown in the appendix.) In addition, overall job treatment information is displayed in the treatment control van in real-time to assist the operator and service company in understanding how the treatment is progressing. This allows for spot checks throughout the treatment process to compare the physical inventories of volumes of additives pumped with those calculated to again insure the treatment is being pumped as planned.

In addition, during the pumping operation there is continual monitoring of the surface lines, equipment, and wellhead to make sure there are no leaks. If a leak does develop, it is either isolated if possible or the treatment is shut down and the leak fixed before pumping is resumed.

The majority of hydraulic fracture treatments are pumped as planned or with changes that are based on the way the treatment is proceeding. On occasion, the formation may be difficult to fracture stimulate, resulting in a rapid pressure increase while pumping; this is called a screen-out. Even if there is a rapid increase in pressure relative to normal increases in pressure due to pumping, the system is still compressible so there is still time to react. As the pressure increases, the fracture treatment operator will start bringing pumps off-line to counteract the rapid pressure increase. In a worst case scenario, if the pressure increases too fast then the pump kick-out will activate and shut down the treatment.

After the Fracture Treatment

After the well has been treated the equipment used in the fracture treatment is rigged back down. At this time there is another safety meeting to discuss any possible issues that may be associated with this rig down. A final physical inventory of materials still on location is conducted to determine the actual volume of materials that was pumped during the treatment. During the rig-down of the pumping equipment steps are taken to prevent any spills and surface contamination. Finally, the operator is provided with a post job report that provides details of the treatment, a summary of what occurred during the time on location, and what was pumped into the well.

Appendix

Nomenclature and Terminology

Treatment Rate (bpm) – the downhole rate that fluid is entering the formation
Hydraulic Horsepower (hhp) – horsepower being applied to the formation while pumping
Wellhead Treating Pressure (psi) – the surface pressure at the wellhead during pumping
Max Pressure (psi) – the maximum WHTP that will be allowed
Bottom Hole Treating Pressure (psi) – pressure being applied to the formation including net pressure
Frac Gradient (psi/ft) – pressure at which fluid will cause the formation rock to part
Pipe Friction Pressure (psi) – friction pressure of the fluid being pumped down the wellbore
Perf Friction Pressure (psi) – pressure drop across the perforations
Hydrostatic Pressure (psi) – pressure the fluid column exerts on the formation
Net Pressure (psi) – excess pressure over frac pressure required to extend the fracture
Instantaneous Shut-in Pressure (psi) – a pressure used to calibrate the frac gradient
Clean Volume (gal or bbl) – volume of fluid pumped without proppant
Dirty Volume (gal or bbl) – volume of fluid pumped with proppant
Proppant Concentration (lb/gal) – the amount of proppant added to one gal of fluid
Proppant – small diameter material used to keep the fracture open
Solid Additive (lb/Mgal) – a solid chemical added to the fluid system for a specific purpose
Liquid Additive (gal/Mgal) – any liquid chemical added to the fluid system for a specific purpose
Pop-off – a mechanical device activates at a preset pressure to prevent damage to surface and downhole tubular
Kick-outs – mechanical or electrical devices that activate at a preset pressure to disengage high pressure pumps
High Pressure Pumps – Positive displacement pumps used for pumping downhole
Centrifugal Pumps – used on the low pressure equipment to mix and move fluid
Additive Pumps – used to inject liquid additives; different types based on the additive type and additive rate
Pressure Transducer – device used to measure and transmit pressure data
Flowmeter – used to measure and transmit fluid flow rates; different types depending on application
Annulus – Area between two concentric casing strings or tubular strings

Figure 6. Simplified Location Schematic

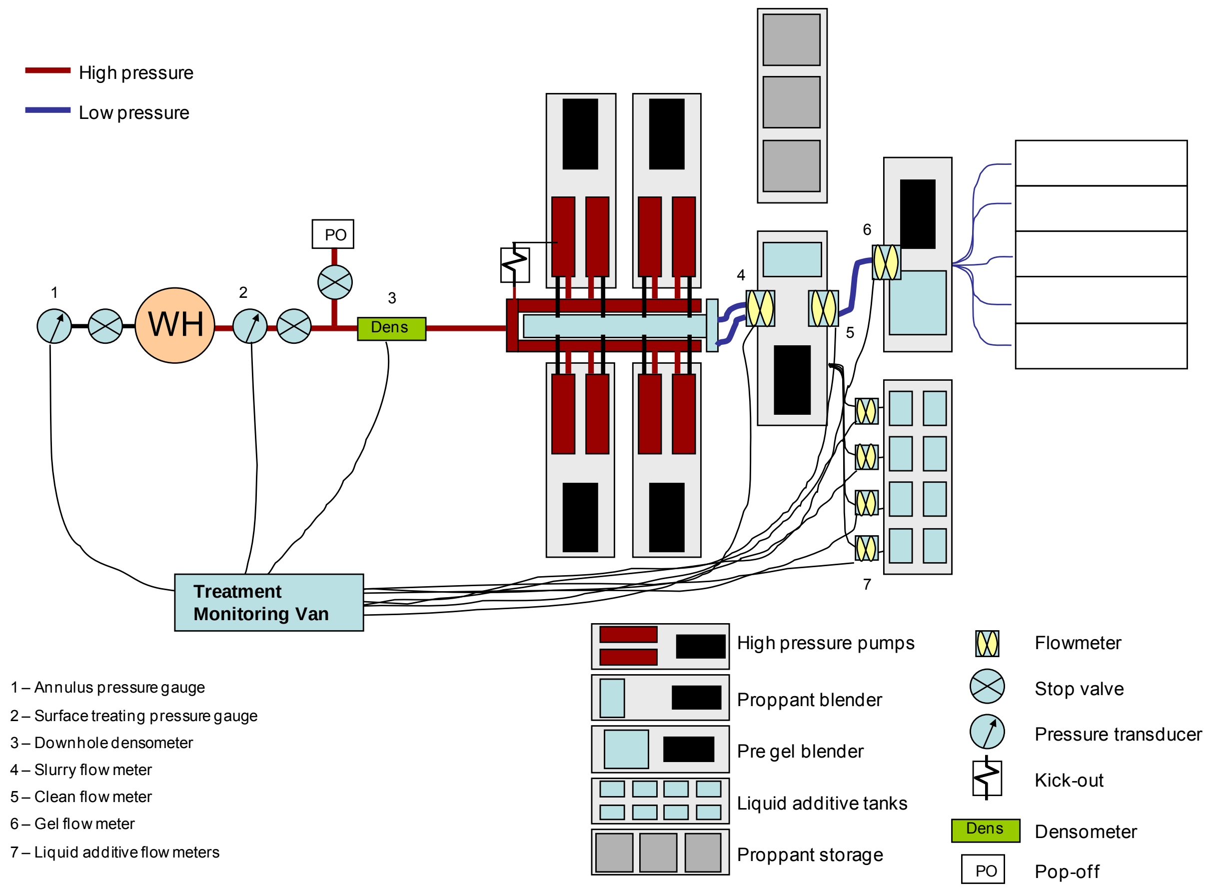

Figure 7. Inside the treatment monitoring van

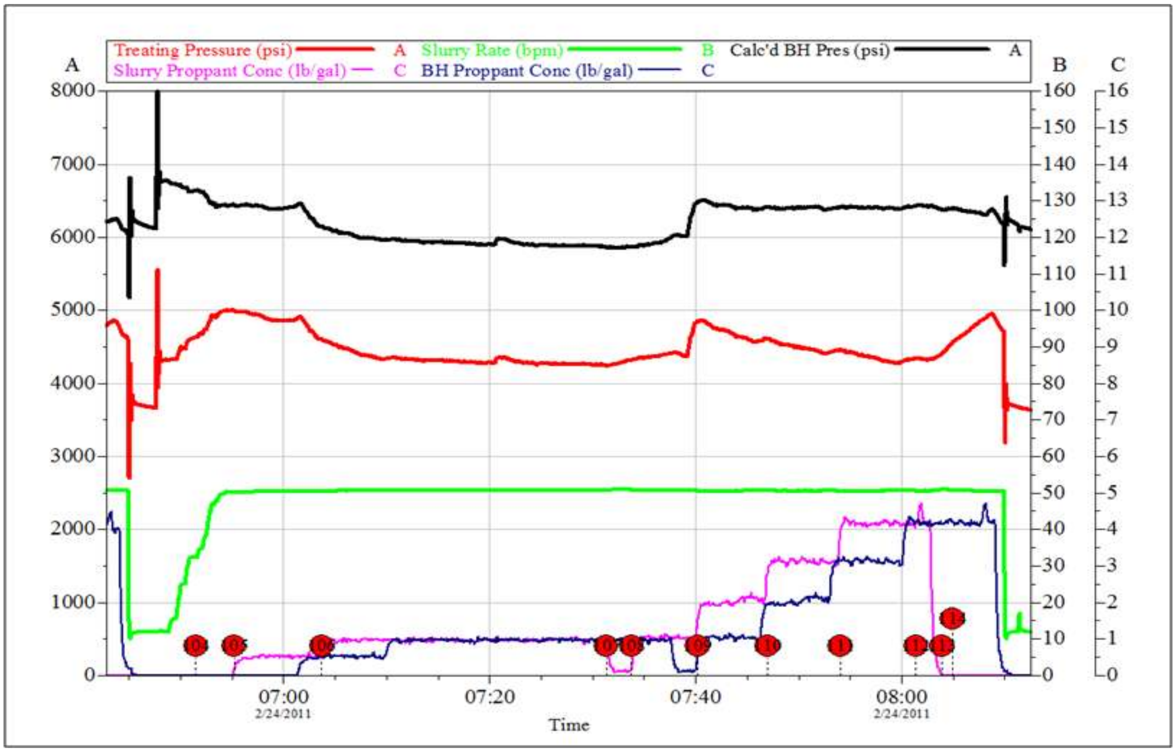

Figure 8 Treatment Chart -- Pressure, Rate and Prop Concentration

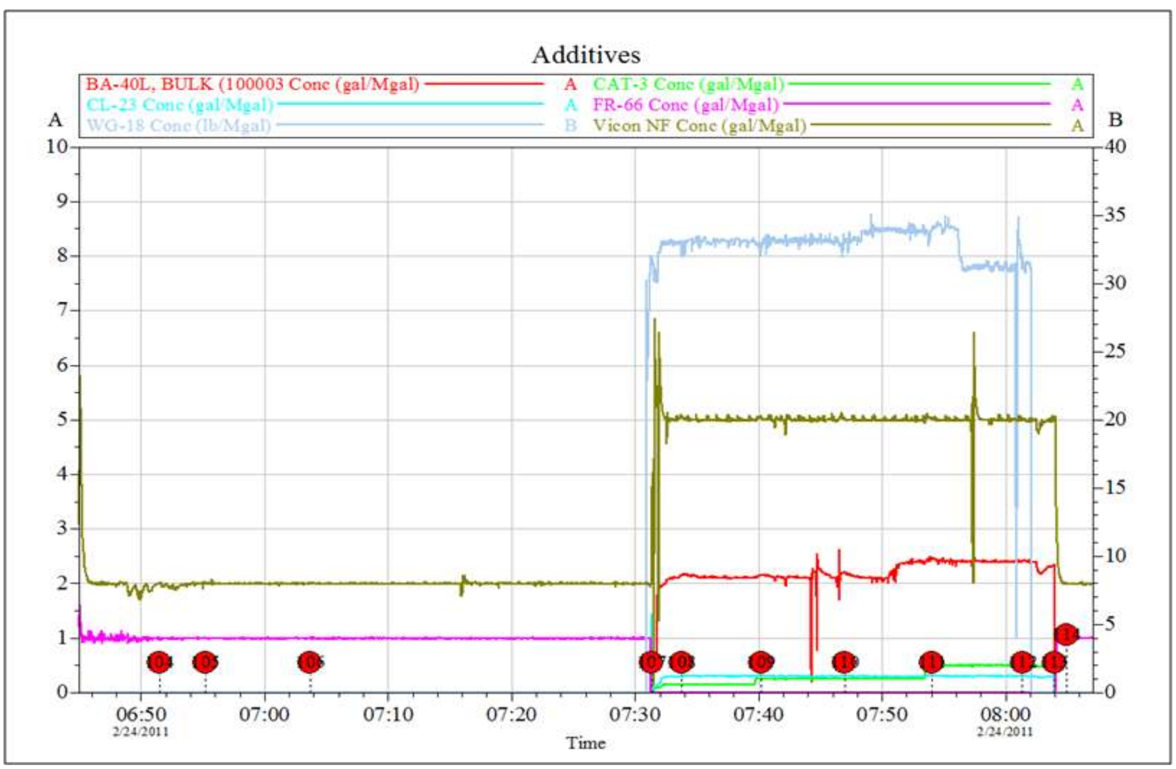

Figure 9. Additive Chart

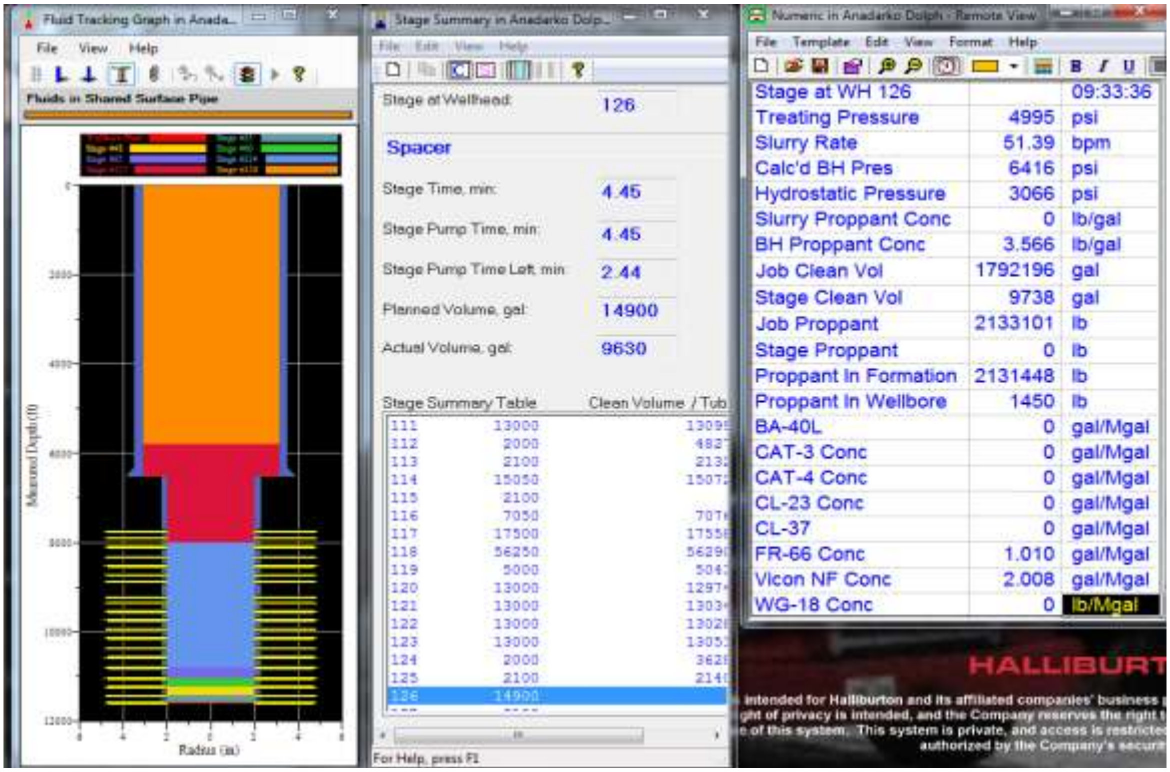

Figure 10. Fluid Tracking, Numeric Value, and Stage Summary Screen

Company: **HALLIBURTON**
Lease: SilverStim
Formation: CW 230 **Location:**

Stage	Fluid Schedule	Volume (gal)	Proppant Type.	Prop Conc. (ppg)	Prop Total (lbs)	Slurry Vol. (gals)	Rate (bpm)	Stage Time (h:min:sec)	Exposure Time (h:min:sec)	CL-37 (gpt)	CL-23 1.3.F (gpt)	BA-40L (gpt)	GasPerm 1100 (gpt)	Clayfix 3 (gpt)	VICON NF (gpt)	CAT-3 (gpt)	CAT-4 (gpt)	FR-66 (gpt)	WG-18 Variable (ppt)
1	FR Water Pad	50000				50000	50	0:23:49	1:18:43				1.50	1.25	3.00			1.00	
2	SilverStim Pad	6000				6000	50	0:02:51	0:54:55	0.50	0.30	0.50	1.50	1.25	3.00	0.25			28.00
3	SilverStim 24 visc	7000	Ottawa 30/50	1	7000	7317	50	0:03:29	0:52:03	0.50	0.30	0.50	1.50	1.25	3.00	0.25			28.00
4	SilverStim 24 visc	33000	Ottawa 30/50	2	66000	35986	50	0:17:08	0:48:34	0.50	0.30	0.50	1.50	1.25	3.00	0.25			28.00
5	SilverStim 24 visc	22000	Ottawa 30/50	3	66000	24986	50	0:11:54	0:31:26	0.50	0.30	0.55	1.50	1.25	3.00	0.25	0.10		28.00
6	SilverStim 24 visc	13000	Ottawa 30/50	3	39000	14765	50	0:07:02	0:19:32	0.50	0.30	0.70	1.50	1.25	3.00	0.50	0.10		28.00
7	SilverStim 24 visc	10000	Ottawa 30/50	4	40000	11810	50	0:05:37	0:12:30	0.50	0.30	0.80	1.50	1.25	3.00	0.50	0.25		28.00
8	SilverStim 24 visc	8000	Ottawa 30/50	4	32000	9448	50	0:04:30	0:06:53	0.50	0.30	0.90	1.50	1.25	3.00	0.50	0.50		28.00
9	Flush	5000				5000	50	0:02:23	0:02:23				1.50	1.25					
								0:00:00											

Total Pump Time: 1:18

TOTAL FLUID: 154000 gal Total Proppant: 250000 165312

	CL-37	CL-23	BA-40L	GasPerm 1100	Clayfix 3	VICON NF	CAT-3	CAT-4	FR-66	WG-18
Final Design Used	50	30	59	231	193	447	33	10	50	2772
Loaded	67	42	79	294	246	564	46	18	68	3470

Pad+SLF+Flush: 154000 gal
Pad+SLF: 149000 gal
Percent Pad: 37.6%
Average Rate: 50.0 bpm
Treatment Down: Casing
Abs. Min. HHP: 6,130 HHP

MAX PRESSURE: 5000 psi S.G.: 0.9
Anticipated Surface Pres: 4743 psi
Perforations: 48
Dia. in: 0.73
Calc. Perf Fric (psi): 11
Est. Well Bore Fric (psi): 1,500

	T Perf	B Perf
Perf Zone #1	6,846	6858 NioA
Perf Zone #2	6,977	6989 NioB
Perf Zone #3		
Perf Zone #4		

WELL-BORE PATH
4 1/2" 11.6# 6846 ft
ft
ft

MAXIMUM CHEMICAL ADDITIVE

	CL-37	CL-23	BA-40L	GasPerm 1100	Clayfix 3	VICON NF	CAT-3	CAT-4	FR-66	WG-18
Pump Rates (gal/min) 50.0 bpm	1.05	0.63	1.89	3.15	2.63	6.30	1.05	1.05	2.10	58.82
Bucket Test Time for 1 gal (min:sec)	0.57	1.35	0.32	0.19	0.23	0.10	0.57	0.57	0.29	0.01

Gelled Fluid = 99000 Linear Gel = SLF = 93000 FR Water = 50000

Figure 11. Blender schedule

A Case History of Tracking Water Movement Through Fracture Systems in the Barnett Shale

Pat Handren
Denbury Resources, Inc

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Staged fracturing has been successfully carried out in the Barnett Shale for the past several years. Over the course of these years diagnostic work has been performed to assess the geometry of the complex network of fractures created during the pumping process. One of the tools used to “measure” the parameters of fracture azimuth, length, height and width of what has been termed as stimulated reservoir volume (SRV) is micro-seismic detection. The observed SRV coverage has proved very useful for predicting potential areas of communication between wells with increased density spacing. This tool has provided information that has led to improved stimulation efforts by many operators.

In the case study area there were two wells that were observed with micro-seismic mapping. The mapping is based on the detection of small seismic events that occur during the fracturing process. The locations of the events are determined by analyzing the signal received at the monitoring tools. Essentially the event is triangulated by looking at the strength of the signals received by receivers oriented in different directions. This method of analysis provides a “map” of where the fractures could potentially be occurring.

The first well was located to the north of the case study well. Four fracture stimulations were done, consisting of approximately 34,000 barrels of water and 340,000 pounds of sand for each stage. The average of the stages was an azimuth of north 45 degrees east and an SRV per stage of about 900,000,000 cubic feet (~21,000 acre-ft). The average height of the SRV was 350’, which means each stimulation stage covered about 60 acres of area. Of interest in this well was the observed growth during the fourth stage. This was the least contained of all the stages, but it was still limited by the lithology change from the Barnett Shale into the Marble Falls formation.

The second well was located to the south of the case study well. Two fracture stimulations were performed, consisting of approximately 20,000 barrels of water and 380,000 pounds of sand for each stage. The average of the stages was an azimuth of north 34 degrees east and an SRV per stage of about 490,000,000 cubic feet (~11,000 acre-ft). The average height of the SRV was 400’, which means each stimulation stage covered about 28 acres of area. One of the most important things observed with the Micro-seismic mapping in both wells is that the height growth was well contained to within the Barnett Shale interval.

Even with the tools available to perform fracture diagnostics operators are still faced with challenges that are difficult to predict. As well density increases it becomes increasingly probable that wells will communicate either through previously created fractures or through adjacent wellbores and then into previously created fractures. The occurrence of this type of communication will be reviewed for a well that was fractured in 2009.

A typical Barnett Shale well in the area has 9 5/8" surface casing set at 850' and is cemented to surface to protect fresh water sands. The well is then drilled to a true vertical depth of about 6700' with a lateral length of approximately 3000'. After drilling to total depth, a 4 ½" production casing string is run to bottom and is cemented in place with cement to 5400' or higher. The top of cement depth is verified with a cement bond log run on electric line. The well is then ready for stimulation. Each stimulation stage is preceded with perforating of three intervals.

The case study well had plans for six staged fracture stimulation. Each stage was scheduled to be pumped at a fluid rate of 100 barrels per minute with an average fluid volume of 17,000 barrels of fluid and 250,000 pounds of sand. If the wells previous evaluated with micro-seismic mapping gave any insight into SRV based on fracture treatment volume, then the estimated SRV would be approximately 410,000,000 cubic feet (~9,400 acre-ft). If an average height is assumed at 375 feet, then the average are covered by each stage would be 25 acres. This would mean that all six stages covered a total of 150 acres. Over the course of performing the stimulations in the well communication was achieved to wells spread over more than 600 acres. The farthest well that was "hit" by water from one of the stimulations was 1,500' away. A total of six wells were affected by water from the study well's stimulations.

The basic conclusions drawn from the both the micro-seismic mapping and the observations made from the study well is that the stimulations stay reasonably contained within the Barnett Shale interval. As well density increases the complexity of subsequent fracture stimulation interaction with adjacent wells increases. If fracture azimuth is known, then a reasonable estimate of well to well interaction can be predicted.

Measurements and Observations of Fracture Height Growth

Norman R. Warpinski
Pinnacle – A Halliburton Service

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Hydraulic fracturing is a process that is necessary for economic extraction of natural gas and oil from unconventional resources such as tight gas sands and gas shales. It is a process that is well understood in its overall behavior and development, but is difficult to quantify in many of the details because of both geologic and mechanistic uncertainty. For example, fine details of the layering are impossible to resolve using the borehole tools available today, and features between wells are difficult, if not impossible, to distinguish unless their scale is extremely large. The mechanistic uncertainty follows from the poor description of the reservoir and the geologic features within, but also from the computational difficulties associated with a complex interaction problem in a heterogeneous material.

Nevertheless, thousands of papers have been written in the petroleum literature to study hydraulic fracturing, and these have provided a wealth of understanding about the behavior of fractures in different environments. These papers have provided field evidence, mineback and coring evidence, laboratory testing, analytical models, numerical models, and a host of other results that have guided the understanding, development and optimization of the fracturing process. What we may be missing in the fine details can be accounted for in overall generalized findings about the fracturing process.

Geology, Geology, Geology

It should be obvious from the literature that we only have a limited ability to direct fracture growth; Mother Nature does not let go easily. The best example is fracture azimuth (the direction a fracture propagates), which is dictated by the in situ stress that exists at the hydraulic fracture location and is very difficult to alter. Fractures will propagate in the same direction all across a field. A second general finding is that the layered earth sequence makes vertical fracture height growth difficult, thus generally promoting the growth of length over height. Height growth is inefficient due to the variable layer properties, the large number of interfaces, the rapidly varying stress that can

Figure 12. Mineback photograph of complex fracture

occur vertically, and the potential for a large number of energy-dissipative mechanisms that can occur in such an environment.

Figure 12, for example, shows a mineback photograph of a hydraulic fracture that has very complex behavior that is largely due to geologic factors, such as the stress state at this location and the interfacial properties. Fractures are not single planar features that extend long distances; they are a series of interconnected fracture segments that have many internal terminations and interactions with the local geologic conditions (Warpinski and Teufel 1987).

Figure 13 shows a second example of the complexity that can occur as hydraulic fractures intersect natural fractures and other geologic discontinuities (e.g., interfaces). There are many offsets and some splits that occur as part of this interaction process, the details of which are largely driven by the local stress state and the material properties in conjunction with the treatment conditions. In many instances, natural fractures, faults, and interfaces have been observed to terminate fracture growth, thus providing a complete containment feature.

Figure 13. Mineback photograph of offsets & splitting.

The in situ stress has a dominant role in all of these processes, but also directly affects vertical hydraulic fracture growth. Fractures are impeded from growing vertically by higher stress layers. This might appear to be an unusual case because stresses decrease as the depth becomes shallower, but measurements have shown that large stress contrasts exist in sedimentary basins at all depths.

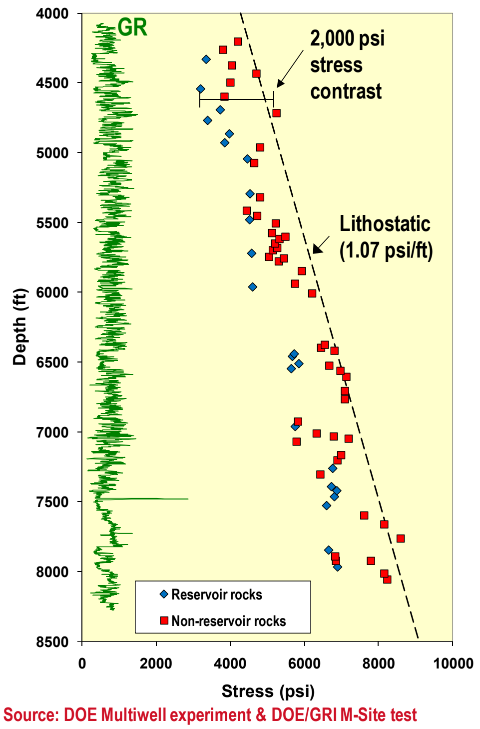

Figure 14. Measured stress profile in Mesaverde.

Figure 14 shows an example of the results from a stress measurement program at the DOE funded multi-well experiment in the Mesaverde formation located in the Piceance basin (e.g., Warpinski and Teufel 1989). The stress measurements made in reservoir rocks (sandstones) are shown in blue, whereas the non reservoir shales, mudstones, and siltstones are shown in red. The stress contrasts are often in the range of 1,000 – 2,000 psi. While the overall trend is one of decreasing stress with shallower depth, the large variations make it unlikely that fractures would grow very far across such a section. Fractures that grow out of zone and propagate vertically upward would quickly hit another low stress layer and tend to grow laterally in it. Should the pressure overcome the next higher stress layer above it, then the fracture would grow and again hit a lower stress layer, and also result in preferential lateral growth. Repeated crossing of these layers is an inefficient process that soon uses up the fluid and energy.

All of these processes and mechanisms have been verified in laboratory testing and modeling. We now have the laboratory equipment to study layered and fracture rocks and the computational tools to study fracture behavior in a discontinuous medium. As noted above, the exact details may be difficult to determine because of the poor understanding of the geologic details, but the overall behavior is very clear.

Diagnostics Tell the Story

While all of the mechanisms discussed above provide the understanding of what is occurring as fractures propagate, it is the advent of far-field diagnostic technologies that have given us a full picture of the propensity of fractures to propagate laterally. Although tiltmeter deformation measurements have been applied more often and longer, it is microseismic technology that has been the most revealing.

Microseisms are small earth movements that occur in the vicinity of a hydraulic fracture due to inflation of that fracture and leakoff of high pressure fluid into the formation. These two mechanisms cause changes in both stress and pressure that can induce complex shear slippage processes. These microseisms emit seismic energy that can be detected at receiver arrays located in adjacent wells, and the waveform data, in conjunction with a velocity model, can be processed to extract microseismic locations. The sum of these locations yields a map of where the activity is occurring which describes the fracture.

One common question is that of validation. How can we be sure that the microseismic data is representative of the true fracture behavior? The answer to that question is in the results from several validation experiments, the most extensive of which was the DOE/GRI funded M-Site test in Colorado. (Warpinski et al. 1998) Figure 15 shows a side view representation of the testing results from M-Site, in which several approaches were taken to verify the microseismic data. There were two monitor wells with seismic receivers to capture microseismicity, but there were also tiltmeters cemented in place in one of the wells to measure the earth deformation and compare the mechanical behavior with the microseismic behavior to verify fracture height. In addition, intersection wells were drilled to verify fracture azimuth and examine the fractures in core or with imaging logs, but one of those intersection wells was drilled prior to fracturing and instrumented with pressure gages. During fracturing, the time at which the hydraulic fracture intercepted this well could be determined by an observed increase in pressure, thus providing a fracture length at that time which could be compared to the microseismic length. All parameters – length, height, and azimuth – exhibited close agreement between the microseismic results and the verification technologies.

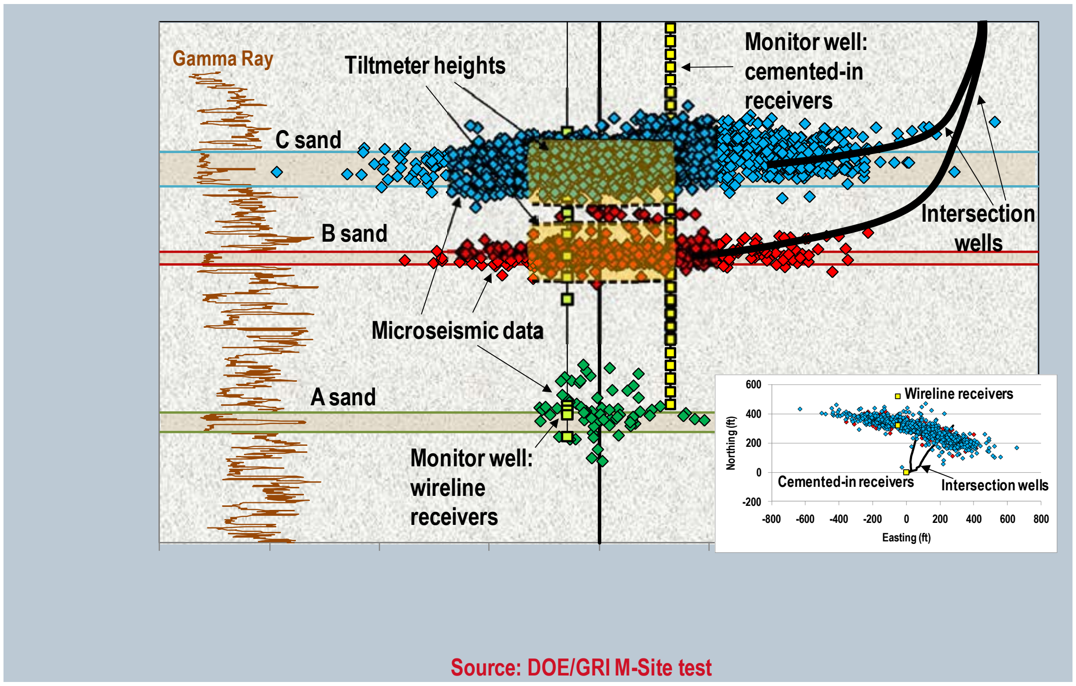

Figure 15. Overview of DOE/GRI M-Site hydraulic fracture diagnostics field test site.

While only a very limited number of industrial fracture monitoring projects have been published, there are many thousands that have already been done and these provide a comprehensive record of the behavior of fractures in these sedimentary environments. Figure 16 shows a case of a Haynesville shale fracture (Pope et al. 2009) where there is some extensive height growth – on the order of 600 ft. This degree of height growth does occur in some of these deep shale reservoirs and the monitoring provides information that can be used to optimize the process as much as is possible. Any amount of height growth out of zone is undesirable because it wastes fluid, horsepower, chemicals, and time. The point of hydraulic fracturing is to stimulate the reservoir, not the unproductive rocks around it. Monitoring provides information that can be used to figure out ways to minimize this behavior.

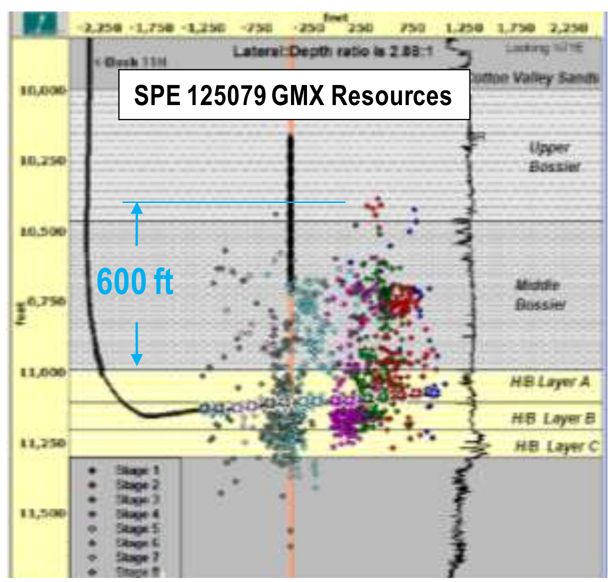

Figure 16. Example Haynesville shale microseismic data.

Since one monitoring test proves nothing and one can always use the best examples, a more compelling result can be demonstrated by showing all of the fracturing results in a basin in a correlated plot. Figure 17 shows the results of nearly 2400 fractures in the Barnett shale prior to mid-2010 – everything that was monitored up to that time (Fisher 2010). The plot has been sorted by depth, with deeper wells on the left. The perforation depth is shown, along with the top and bottom of the hydraulic fracture as measured by the microseismicity. Although difficult to see and read, the data are also colored by county. In addition to the fracturing results, the deepest water well in each county, as obtained from the USGS web site, is also plotted at the top.

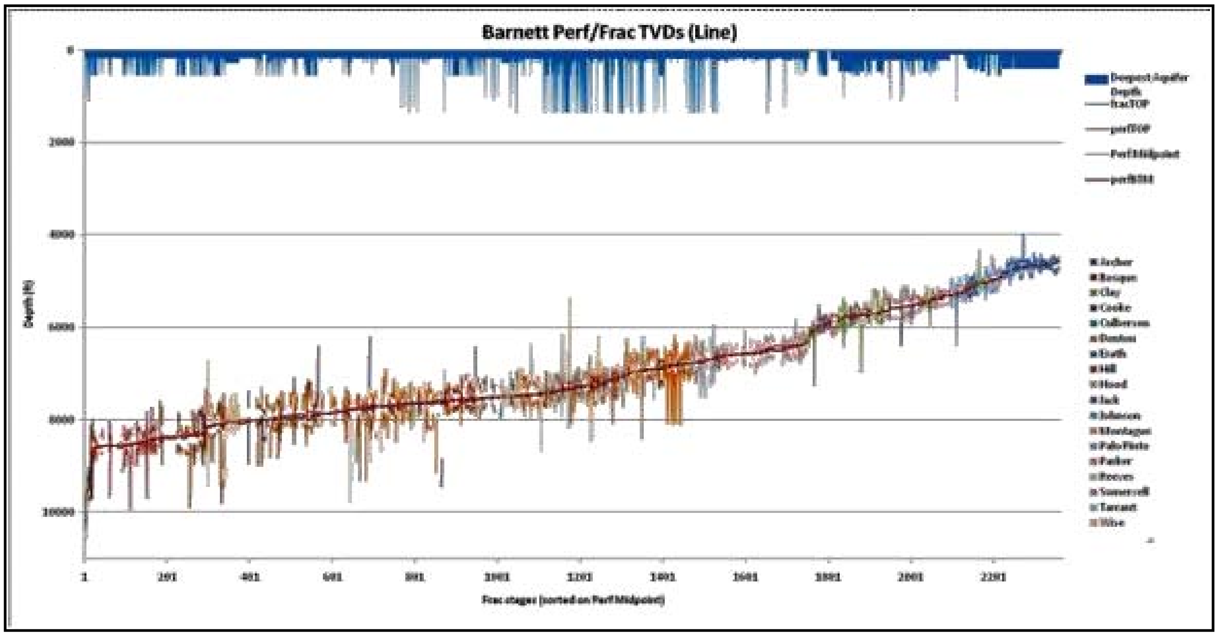

Figure 17. A compendium of microseismic fracture diagnostic results in the Barnett shale relative to known aquifers.

These results show that fracturing does not intrude on the aquifers. There is a limit to how much a fracture can grow vertically, even in the most advantageous conditions. There is considerable variability in fracture height in this plot, with much of it due to intersections of faults. However, even the most extreme cases do not extend vertically anywhere close to the aquifers. Similar results have been compiled for the Woodford and the Marcellus shale and those plots look similar.

The fractures that have been compiled in Figure 17 are for relatively deep injections, but there are many reservoirs that are much shallower. One might expect that fracturing to surface would be common in shallow reservoirs, but Mother Nature again conspires against vertical fracture growth by reversing the stress field at shallow depths. Hydraulic fractures at depths greater than ~2,000 ft are mostly vertical, but at depths less than ~1,500 ft, they are either horizontal or mostly horizontal (a vertical component in some layers) due to the overburden stress being generally greater than the horizontal stresses at shallow depths. There is a wealth of tiltmeter data on ~10,000 fractures that details how fractures have primarily vertical components at depth, but have a larger percentage of the fracture growing horizontally in shallow environments.

Summary

There are over seventy years of experience in conducting hydraulic fractures, a multitude of fracture models, thousands of petroleum engineering papers on the subject, many years of studying fractures using minebacks, corethroughs, laboratory experimentation and numerical analysis, and most recently the application of fracture diagnostic measurements in thousands of projects across North America. All of this knowledge and information has provided a sound understanding of the basic principles and general behavior of hydraulic fracturing.

Vertical propagation of a hydraulic fracture across layers is very inefficient and it is difficult to obtain extensive vertical growth. Fracture heights of several hundred feet are common, and they may occasionally exceed 1,000 ft in a few deep reservoirs. However, there has never been an observed case of a hydraulic fracture propagating thousands of feet vertically to intersect an aquifer. In shale projects where large fluid volumes are injected, the thousands of diagnostic measurements have consistently shown that fractures remain thousands of feet deeper than the aquifers.

Fractures do occasionally intersect faults, but the diagnostic information shows that vertical growth is also limited when this occurs. Some of the largest measured heights occur in cases where a fault has been intersected, but growth is equally likely to be downward as upward and it is typically only about twice the height of a normal fracture.

Shallow hydraulic fractures are not observed to grow vertically because of the changing stress state. Less than about 1500 ft, the overburden stress is the least principal stress and this causes fractures to be primarily horizontal at shallow depths. Some vertical components may occur, but they are typically very limited.

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Sustainable Fracturing Rationale to Reach Well Objectives – The Impact of Uncertainties and Complexities on Compliance Assurances

Ahmed Abou-Sayed
Advantek International

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The presentation will discuss lessons learned; extract best practices and guidelines applied to injection of fluids and slurries during fracturing and exploration and production (E&P) associated streams disposal (wastes, produced water, drill cuttings, and solids/proppant flow-back). Fracture generation, propagation and multiplication during multiple injections in same well, batch injections and re-fracturing is covered. Design requirements, monitoring and assurance of containment for environmentally safe injections are covered. Results from major worldwide injection projects are viewed from operator's and regulator's perspectives.

Design and Rationale for a Field Experiment using Tracers in Hydraulic Fracture Fluid

Daniel J. Soeder
U.S. Department of Energy, National Energy Technology Laboratory

The economic recovery of natural gas from organic-rich shales requires the use of horizontal boreholes and staged hydraulic fracturing. Many questions have been raised about the potential threat this production method may pose to groundwater. Field-based measurements to gather hydrologic and geophysical data from a representative hydraulic fracture treatment in the shale could help ascertain the movement of hydraulic fracture fluid in the ground, and determine how close it might come to contaminating drinking water supply aquifers.

Geophysical field data collected by microseismic methods show the extent and dimensions of hydraulic fractures created in lateral boreholes as a stimulation technique for shale gas production. The data indicate that hydraulic fractures do not approach closer than several thousand feet below the freshwater aquifers above the Barnett Shale of the Fort Worth Basin, and the Marcellus Shale of the Appalachian Basin, the two major shale gas production areas in the U.S. (Fisher, 2010). Nevertheless, there is still a degree of uncertainty concerning the potential effects that such fracturing treatments might have on groundwater. In particular, the possible migration of fracturing fluids from the target production formation into drinking water supply aquifers remains a hotly-debated topic. The absence of rigorous data to support either side in this argument has left the general public confused, concerned, and in some cases frightened.

The proposed field experiment would begin by collecting representative groundwater samples for baseline analysis along the planned trajectory of the horizontal borehole prior to drilling. Structural features will be located by a seismic survey during site characterization, and additional groundwater sampling points will be installed over structures such as faults, which might provide conduits for hydraulic fracture fluids to move out of the stimulation zone and into aquifers. Soil gas samples will also be collected from locations above the laterals and analyzed for any traces of natural methane or radon gas potentially released by the fracture treatment. Prior to hydraulic fracturing, a conservative tracer will be placed in the fracturing fluid. Microseismic and other advanced geophysics will be run above the laterals during the hydraulic fracturing process to map the length and orientation of the induced fractures. A series of groundwater samples will be collected before, during and after the drilling and hydraulic fracturing operations, and analyzed for the tracer. Groundwater sampling will be carried out at regular intervals for a few weeks to months after the hydraulic fracturing to determine if there is any upward movement of fluids over time.

After completion of the hydraulic fracturing, a vertical borehole will be drilled down to the Marcellus Shale, and continue through it to the underlying Oriskany Sandstone. The drilling will be paused at water-bearing formations, such as sandstones and limestones, to collect formation water samples. The samples will be analyzed for the tracer, to determine if it has contaminated any of the deeper saltwater aquifers. Water samples will also provide data on the chemistry of natural formation brines in the basin, and determine if the brines in the Marcellus are chemically related to other formation waters. Data collected from this experiment should provide insights into the location of hydraulic fractures in relation to aquifers, the potential for the upward movement of hydraulic fracturing fluid to contaminate groundwater, and the geochemistry of Appalachian Basin formation waters in comparison to the Marcellus Shale.

Reference: Fisher, Kevin, 2010: Data Confirm Safety of Well Fracturing, The American Oil & Gas Reporter, July 2010

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

Scott Cline, PhD Petroleum Engineering
Stanley, NY

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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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Summary and Abstracts from Theme 3: Well Integrity

Summary of Presentations from Theme 3: Well Integrity

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Technical Presentations

<u>The first set of technical presentations in this theme addressed pre- and post-HF well integrity assessment methods</u>.

Jim Bolander, Southwestern Energy, introduced Theme 3. Mr. Bolander then discussed the factors that affect mechanical integrity of HF wells, as well as methods and techniques used to assess internal and external mechanical integrity at different stages in the life of the well. He described two main causes of mechanical integrity failures: cement channeling and casing leaks. Mr. Bolander concluded that proper planning, assessment, and remediation throughout the life of the well are key to maintaining mechanical integrity.

Talib Syed, TSA, Inc., described wellbore design and monitoring techniques that are used to ensure well integrity before, during, and after stimulation. He discussed factors to consider in casing design, methods for cement evaluation, as well as methods for evaluating internal and external mechanical integrity, including the Ultrasonic Imaging Tool (USIT) and traditional logs. Mr. Syed emphasized the importance of proper casing design, cement placement, and continuous monitoring through the life of the well. He also recommended that wells for refracturing be carefully selected and closely monitored.

<u>The final set of technical presentations described case studies for mechanical integrity</u>.

Lloyd Hetrick, Newfield Exploration Company, presented a hypothetical case study in an unconventional shale play with multiple zones. Mr. Hetrick discussed potential mechanisms for mechanical integrity failures at each stage of well construction, stimulation, and production. He also described methods that could be used to assess mechanical integrity at each of these steps, as well as potential remediation actions. He called attention to adjacent wells and the impacts they could have on well integrity.

Briana Mordick, Natural Resources Defense Council, presented two case studies of risks to drinking water from oil and gas wellbore construction. In Bainbridge Township, Ohio, a poor cement job, the decision to proceed with fracturing despite the poor cement job, and an overpressured annulus (due to shutting in the well) led to gas migration into a drinking water aquifer. The gas then entered homes through domestic water wells completed in that aquifer, resulting in an explosion in one house. In Garfield County, Colorado, natural gas and other contaminants were found in a local creek, which lead to an investigation of water quality in the area. While some of the contamination was likely caused by faulty cementing in gas wells, other sources may have contributed to the contamination. Ms. Mordick described the challenges inherent in determining sources of contamination and recommended that future studies investigate contamination risks from both drilling fluids and fracturing fluids.

Summary of Discussions Following Theme 3: Well Integrity Presentations

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Corrective action. Options for corrective actions on wells depend on when the problem occurs and what type of problem it is. According to some participants, if there is an issue during a pressure test in the pre-fracturing stage, operators have the ability to shut down operations and perform remediation. The following are corrective action options suggested by participants:

- For a shallow mechanical issue, operators can pull the casing and replace it. If it is a cementing issue, there are remedial cementing options ("squeezing cement"), though this adds additional risk due to squeeze perforations in the casing.
- If a problem occurs during fracturing, the operator can immediately shut down the well.
- In a horizontal well, stages can be isolated.

A participant asked for more information on shutting in a well. A participant responded that when fracturing stops or a well is shut in, pressure immediately decreases, lowering the potential for fluid flow. The participant added that keeping a well shut in for a period of time lowers the pressure further, though this may lead to casing problems. Participants stated that monitoring annular pressures over the life of the well is essential. A participant recommended that monitoring, recording, and reporting should not stop during or after the well is shut in. A participant suggested that the pressure fall-off curve can provide important information about the fracture treatment.

Use of logs and other tools. A participant asked if logs are required by regulatory agencies, or if operators only run logs when they suspect a problem. Participants explained that, depending on the state, certain issues (such as casing leaks) must be reported. The operator must work with the state to develop a remediation plan, which generally includes using logs to understand the nature of the problem. Participants indicated that in other situations, logs are run proactively. For example, in Arkansas, a new regulation requires monitoring cement placement during the cement pumping phase and monitoring annular pressures during fracture treatment. According to a participant, the use of cement evaluation tools is also a standard process in new development areas. The UltraSonic Imager Tool (USIT) is widely used in the Alaskan North Slope in various kinds of production wells. The participant stated that the USIT is especially useful in water-alternating-gas enhanced recovery wells, which can have well integrity issues not detectable with conventional MITs.

Pressure test slope interpretation. A participant asked if a negative net pressure always means a fracture has gone out of zone. Another participant stated that the net pressure plot is a key tool in the field, and it is essential for understanding the qualitative analysis of pressure test slope changes. This participant explained that a slightly positive slope indicates fracture extension, though a negative slope occurs at the very beginning of height growth. According to the participant, a negative slope after the initial height growth indicates the fracture is potentially growing out of zone; in severe cases, a vertical slope will indicate a pressure out or screen out. In these situations, however, the participant stated that pressure and volume constraints will halt fracture growth. A participant added that if fracture height is very large, the pressure signature may no longer indicate fracture growth. Another participant stated that not every negative pressure response indicates uncontrolled vertical height growth.

Property transfer. A participant asked what information is available to operators who are acquiring new properties and wells. Other participants responded that operators have access to well-by-well records from the previous operator. In addition, information is available from the state. Operators also visit the site. A participant stated that, in general, the purpose of these well record reviews and inspections is determining the potential value of the property, not searching for defects in the wells.

Water supply wells and water quality. A participant asked whether nitrates in drinking water wells could be due to faulty water well construction. A participant stated that this is possible, though it is more likely that the presence of nitrates is due to natural recharge or infiltration processes (from agricultural sources). Other participants emphasized the importance of good construction of water wells. They noted that water wells often take water from across many zones and are not subject to much regulation; in addition, contamination is often introduced into water wells due to their poor construction. One participant noted that ground water is often contaminated before HF activities take place, though the public generally does not realize this. For example, benzene, toluene, ethylbenzene, and xylenes (BTEX) and endocrine disruptors may come from nearby waste water treatment plants or gas stations. Another participant noted the long history of naturally-occurring natural gas in water wells in Garfield County, Colorado. A participant noted that, because of these concerns, it is in everyone's best interest to gather baseline water quality data; it protects both residents and industry and provides important data for regulators and scientists. A participant recommended that EPA involve hydrogeologists in the study and take into account chemicals that are already present in ground water.

Neighboring fields and fracture contact. A participant asked if operators working on neighboring fields communicate with each other. Responses indicated that operators do communicate about their activities and coordinate with each other, especially in areas with a high potential for fracture contact. For example, operators may shut in wells to create a pressure barrier to other fractures. One participant noted that in the Barnett and Haynesville, operators may postpone fracturing activities to avoid impacts to certain procedures being conducted at neighboring sites. Another participant stated that his company may delay well completions within a single field to avoid interference. In addition, participants indicated that drilling programs are planned so that new wells do not interfere with currently producing wells. Participants added that state regulators are aware that fracture contact occurs and that operators manage the situations within the industry. However, operators do not have a right of refusal for fracturing in neighboring areas (i.e. operators cannot force other operators to refrain from drilling nearby). According to participants, fracture contact and well communication are well-to-well issues, not well-to-surface issues.

Small operators. A participant asked whether small operators use the same best practices as larger companies. Participants indicated that best practices are generally used industry wide, though they may be inconsistently applied by both large and small companies. One participant stated that smaller operators have more at stake in a single HF job, because shut down or litigation problems would have a larger effect on the company. Another participant added that small companies approach operations in a wide variety of ways, both positive and negative.

Abandoned wells. Multiple participants referenced large numbers of abandoned wells with unknown locations in Pennsylvania and West Virginia. The participants indicated that this is of great concern to operators, because it creates the potential of fracturing into an old well that may or may not be properly plugged.

The Garfield County, Colorado case study (reference to Mordick, "Risks to Drinking Water from Oil and Gas Wellbore Construction and Integrity: Case Studies and Lessons Learned"). A participant asked about the compositions of fluids analyzed in the Garfield County case study. The presenter clarified that, in most cases, the produced gas and fluid were representative of the Mesa Verde Formation, and little evidence of cross flow between the Wasatch and the Mesa Verde Formations was found.

Multi-well pads and well spacing. A participant noted that well pads typically have multiple wells and recommended that fracture modeling and the planned EPA study take this into account. According to this participant, well integrity is important, but it is essential to consider groups of wells that are operating close together spatially and temporally. The participant emphasized that the fourth dimension, time, is very important. Other participants indicated that operators are aware of these issues and take them into account in modeling. In addition, participants stated that the same best practices generally apply to single and multiple wells. Another participant added that multi-well pads reduce the environmental footprint of drilling, though another participant noted that it greatly increases well density and the chance for fracture interaction between the multiple, closely located wells.

Regulatory issues. A participant described the Colorado Oil and Gas Conservation Commission's regulatory response to concerns about HF. The participant noted that state agencies and regulators are continuously addressing new challenges. Another participant noted that state regulations were updated in response to both the Garfield County, Colorado, and Bainbridge Township, Ohio, incidents reference in the presentation given by Briana Mordick.

Abstracts for Theme 3: Well Integrity

Abstracts were submitted to U.S. EPA by the presenters for use in this proceedings document. Not all presenters submitted abstracts of their presentations.

Assessment Methods for Well Integrity during the Hydraulic Fracturing Cycle

James Bolander
Southwestern Energy

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.

Introduction

The objective will be to evaluate well integrity of casing and cement during the drilling and completion phases surrounding hydraulic fracturing. Critical processes will be evaluated using passive monitoring techniques (pressure and volume measurements) and direct mechanical techniques to determine effectiveness of casing and cement to protect drinking water resources.

As defined by the EPA Draft Study Plan, drinking water resources will include "any body of water, ground or surface, that could currently, or in the future, produce an appropriate quantity and flow rate of water to serve as a source of drinking water for public or private water supplies."

The primary focus of this assessment will be to concentrate on well integrity during drilling and completion activities associated with running and cementing of production casing operations, completion activities including the hydraulic fracturing process and post-frac activities. Many of the solutions discussed are based on a conventional cased and cemented completion; however, most of the methods discussed will be applied over any type of well configuration.

The purpose of this paper will be to discuss assessment methods and will not expand into remedial solutions to meet hydraulic fracturing or producing well criteria.

Pre-frac Evaluation

The first step to evaluating well integrity of the production string will be to monitor and interpret the pressures and volumes associated with the primary cement job. Key issues to review include test results of the field blend samples (if applicable), actual cement slurry density, cement slurry volumes, pump pressure, fluid return volumes, displacement volumes and lift pressure. Based on the well design, the amount and type of cement will be determined to achieve zonal isolation and sufficient coverage for isolation above the zone(s) to be completed. Knowing the design parameters (estimated TOC, hydrostatic pressure and displacement volumes) are key in the on-site monitoring of the treatment. Ensuring that the cement blend is correct and that the correct dry cement / mix water ratio is followed is a critical factor to ensuring the proper quality of cement. Monitoring return volumes and lift pressure will be the first indication of adequate coverage of the productive horizon, any hydrocarbon strata or any strata containing protected water. Monitoring the displacement volume will allow the estimation of the cement quality at the casing shoe. Monitoring and evaluating these key components of the cement job will assist in planning of the initial steps of a well's completion.

After the production casing has been set and cemented a priority needs to be confirmation of the wellbore integrity prior to moving forward with perforating and the hydraulic fracture processes.

This confirmation process involves measuring the presence and quality of the cement bond or seal between the casing and the formation and confirmation of the mechanical / pressure integrity of the casing or tubing.

Confirmation of cement presence and quality can be obtained using various wireline tools which can confirm the presence, height, bond and overall quality of the cement. Based on the results of the pressure and volume monitoring of the cement job, different steps may be chosen to confirm that an adequate seal is present.

Case #1 – Proper density, proper returns, lift pressure and displacement observed during primary cementing. If design was sufficient for isolation and field conditions are known, a temperature log may be run which can determine and confirm the top of cement (TOC) measuring the heat change of cement during the setting phase. Based on average curing time, this log should be run within the first 8 – 24 hours of pumping. Another wireline log option would be a conventional cement bond log (CBL). The CBL operates on an acoustic principle: it transmits a signal and measures the time travel from a set distance from transmitter to receiver. Understanding the travel time of free pipe and empirical standards based on pipe size and cement type are key in understanding the quality of cement bond and isolation that is present, as well as the TOC. It is recommended to allow the cement to set a minimum of 48 hours prior to running the CBL. If necessary, pressure can be applied to the casing during the CBL procedure if a micro-annulus is observed between the casing and cement sheath.

Case #2 – Returns, lift pressure or displacement does not correlate with design criteria. Risk is insufficient coverage or channeling which could jeopardize proper isolation of protected water. If there are no shallow horizons which require coverage and sufficient cement height was designed, a conventional CBL may be sufficient to determine if adequate bonding above your zone of interest is present to maintain pressure control for hydraulic fracturing. If there are concerns about top of cement and quality, a radial ultrasonic tool (CET, USIT, CAST-V) log may be run. The radial ultrasonic tool uses a high-frequency sonic pulse which will give a full 360° interpretation of cement quality. In addition, the ultrasonic tool also measures casing parameters such as diameter and thickness to confirm casing design specifications.

Once top of cement (TOC) and quality have been verified, and are considered adequate for zonal isolation and hydraulic fracturing activities, casing integrity will be addressed. Several studies have indicated that a minimum of 10 feet of zonal isolation is required dependent upon hole and casing size

Casing integrity will be confirmed with a surface-applied pressure test. Based on design criteria (Casing parameter – burst and maximum anticipated treating pressure) the casing and tree will be tested to a pressure greater than the maximum anticipated treating pressure (MATP) with an appropriate safety factor (Burst Safety Factor ~1.3 and/or not less than 500 psi greater than MATP). The pressure test is conducted using a high pressure pump truck and water. With the frac tree valve closed, the tree and casing are tested for an average test time of 30 minutes. The pressure will be monitored and if a pressure drop is observed (10% range), the casing will be removed from service until such time the casing demonstrates full pressure integrity.

If during the pre-frac assessment process, casing and cement integrity are deemed to be insufficient, the well should be removed from service until remedial operations have been completed to restore integrity. Once remedial operations have been completed, repeat the well integrity assessment to determine casing and cement integrity to confirm adequate pressure and zonal integrity will be achieved to perform hydraulic fracture operations and well production operations.

During Hydraulic Fracturing Treatment

Continuous monitoring of key parameters during the frac treatment (surface injection rate and pressure and annuli pressures) is important in the continued monitoring of well integrity. These key frac parameters are important in the evaluation of the post frac analysis (height, length and conductivity) they are also important in the monitoring of well integrity.

Surface injection pressure is a component in the calculation of net pressure (BHTP – Pc), which is an important monitoring tool to determine if there is a loss of well integrity during the frac treatment. A negative slope of the net pressure plot is indicative of excessive frac height growth. This could be attributed to break out of zone and/or confining layer (discussed in previous Workshop Theme) or loss of cement integrity during pumping. If there is a loss in cement integrity, a corresponding spike in annular pressure may be observed.

In addition, monitoring of annular pressures may also indicate a breach in the casing which could result in potential exposure of protected water.

If during a hydraulic fracturing treatment, there is reason to suspect any potential breach in the production casing, production casing cement or isolation of any sources of protected water, cease pumping and perform diagnostic testing on the well as is necessary to determine if breach actually occurred and if remedial operations are required to restore well integrity.

During the frac job process, additional assessment methods may include evaluation of microseismic events near the wellbore which may indicate a loss of cement integrity.

Other evaluation techniques such as use of tracers (chemical and radioactive) are important in the planning and execution of the hydraulic frac treatment but will be discussed in the next section.

Post –frac Evaluation

Similar to pre-frac assessment, post-frac evaluation involves both passive monitoring techniques and direct measurements.

Passive monitoring during the post-frac period includes continuous monitoring of well production rate and pressure data, and fluid and gas compositional data in the flowback and production stages.

- Monitoring of rate and pressure data:
  - Monitor flow rate changes that are anomalous to the wells typical behavior which may include the following: change in gas/liquid rate which could indicate an influx from an external source due to a breach in the casing or tubing.
  - Flowing pressure changes can also be affected due to influx from an external source and should be consistent with rate changes.
  - Monitoring of annular pressures is important throughout the life of the well from initial flowback until abandonment. Changes should be noted and corrective actions taken, if necessary. As stated in API Guidance document HF1, “maximum and minimum allowable annular pressures should be assigned to all annuli and these should consider the gradient of the fluid in each. These limits establish the safe working range of pressures for normal operation in the well’s current service and should be considered “do not exceed” limits.”
- Fluid and gas compositional analysis may also be utilized to monitor for changes in characteristics. An example would be influx of fluids from an external source which could change the flowback/produced fluids base characteristics such as total dissolved solids (TDS). In addition, regular fluid compositional analysis recorded on a well can aid in the determination of scaling and corrosion tendencies.

Continuous monitoring of pressure, flow and gas/liquid is an important tool in the maintenance of a well. In addition to monitoring the above parameters, regular inspection of the wellhead assembly and equipment removed from a well during a workover operation to inspect for leaks and/or corrosion/erosion damage.

Mechanical methods of evaluating well integrity may involve the running of tracer logs after the hydraulic fracture treatment or the running of mechanical and/or electromagnetic inspection tools to evaluate the condition of the tubing and casing in the well. Additional logs may be run which can detect flow behind pipe or a production log which confirms flow pattern within wellbore.

To aid in the post frac analysis of the effectiveness of a well’s hydraulic fracture treatment, the job may be traced using radioactive tracers throughout the treatment to confirm the placement of the fluids and proppant during the job. A multiple isotope gamma-ray (GR) tool is run in the well after the treatment to measure the location of the isotopes to confirm placement within the perforated interval. The tool is limited to measurements near the wellbore (<2’) which can also be used to determine any channeling behind the casing during the fracture treatment which could compromise well integrity.

Another tracer method is the use of chemical tracers in the hydraulic fracturing fluids. Specific chemical tracers can be placed in the frac fluid at different stages to confirm flowback of fluids from different stages. This confirmation can be used to determine if all frac stages are contributing and can also be used to fingerprint flowback fluids, if necessary.

During the life cycle of the well, regular maintenance may be required which includes workover operations in which tubing and packer installed in the well will be pulled out. Visual inspection of the equipment is important as mentioned above to document the condition of the equipment. In addition, mechanical inspection logs may be run to verify the condition of the casing. A mechanical multi-finger caliper log can be run which physically measures the internal diameter of the casing and its condition. Depending upon casing ID, the caliper tool may record as many as (64) measurements of the internal diameter measuring changes in ID which would detect corrosion pitting and possible holes or splits in the pipe. Electromagnetic flux and ultrasonic tools can be run which will measure the changes in internal diameter as well as casing thickness.

These inspection tools can be run throughout the life of the well to document changes of the casing's condition over time. Understanding the condition of the casing over time is important in the planning of future operations such as refracturing and/or recompletions in the well to maintain well integrity over the well's life cycle.

Conclusion

There are many techniques available from passive monitoring to use of mechanical tools to monitor the integrity of the well throughout the well's life cycle. Proper planning and documentation is important to maintain well integrity and ultimately protection of the environment.

References

American Petroleum Institute, API Guidance Document HF1, "Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines", October 2009

U.S. Environmental Protection Agency, "Draft Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources", February 2011

Various Vendor Technical Brochures and Technical Specification Sheets on various wireline tools (Schlumberger, Baker Hughes (Atlas) and Protechnics)

Pre and Post Well Integrity Methods for Hydraulically Fractured/Stimulated Wells

Talib Syed, P.E.
TSA, Inc.

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.

Wellbore integrity is important to ensuring that reservoir formation fluids are brought to the surface in a controlled and safe manner, and do not migrate into overlying fresh water aquifers/underground sources of drinking water (USDWs). This paper will look into wellbore design and monitoring techniques that are critical in assuring that wellbore integrity is maintained in conjunction with hydraulic fracturing/stimulation completion practices.

The subsurface zone or formation containing hydrocarbons produces into the well, and that production is contained within the well all the way to the surface. This containment is what is meant by the term "well integrity". NORSOK D-010 defines well integrity as "Application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life-cycle of a well". Wellbore integrity as related to hydraulic fracturing can be divided into three areas: pre-hydraulic fracturing design and completion aspects to ensure wellbore integrity; techniques to verify that wellbore integrity is maintained post-hydraulic fracturing; and the potential impact on long-term wellbore integrity (casing and cement) from re-fracturing stimulations.

Well Design and Construction

Casing Setting and Design

As is required in all engineering designs, surface equipment and down-hole tubular are designed for the anticipated operating pressures. This design requirement results in the proper selection of appropriate casing and tubing grade and weight to avoid wellbore collapse. There is a higher risk of compromising the casing integrity during drilling operations. The following points should be considered in casing design (NORSOK 2004):

- Planned well trajectory and bending stresses induced by doglegs and curvature
- Maximum allowable setting depth with regards to kick margin
- Estimated pore pressure development
- Estimated formation strength
- Estimated temperature gradient
- Drilling fluids and cement program
- Estimated casing wear
- Setting depth restrictions due to formation evaluation requirements
- Isolation of weak formations, potential loss circulation zones, sloughing and caving

- Metallurgical considerations
- Potential for H_2S and CO_2
- Equivalent circulating density (ECD) and surge/swab effects due to narrow clearances
- Geo-tectonic forces applicable

The casing is exposed to different loading conditions during various well operations (landing, cementing, drilling, production). It has to be designed to withstand tensile, burst, and collapse loads. Since it is impossible to predict the magnitude of these loads during the life of the casing, the design is based on a worst-case scenario. The casing rating also deteriorates with time (wear and tear). Therefore, safety factors are used to make sure that the casing could withstand expected loading conditions.

Collapse pressure is mainly due to the fluid pressure outside the casing (due to drilling fluid or cement slurry). Overpressure zones could also subject the casing to high collapse pressure. The casing's critical collapse strength is a function of its length, diameter, wall thickness, Poisson's Ratio etc. Burst loading is due to the fluid pressure inside the casing. Severe burst pressure occurs if there is a kick during drilling operations. The tensile stress originates from pipe weight, bending load and shock load. The axial force due to pipe weight is its weight in air less the buoyancy force. Bending force results when the casing is run in deviated wells where the upper portion of the casing is in tension and the lower portion is in compression. Shock load is generated by setting of the slips and application of hoisting brakes. The sudden stoppage when casing is run generates stress waves along the casing string.

In addition to the three loading conditions described above, casing design should also consider the likelihood of buckling, piston and thermal effects. Buckling results when the casing is unstable (e.g. partially cemented). The casing string will exhibit a helical configuration below the neutral point, resulting in rapid wear at the neutral point and eventually lead to casing failure. Piston force is due to the hydrostatic pressure acting on the internal and external shoulders of the casing string while thermal effects refer to the expansion or shortening of the casing due to increase or decrease in temperature.

Cementing the Casing/Liner

The quality of the cementing operation is also critical in maintaining wellbore integrity. Besides the selection of the proper cement systems, the placement of cement and the quality of the cement job are critical elements in assuring the well's integrity. It is very important to thoroughly circulate and clean out the well prior to cementing in order to prevent mud mixing into the cement, causing cavities or channels, resulting in potential cement degradation and/or creation of leakage pathways for the formation fluids.

Well deviation can also affect the quality and presence of the cement. Drilling mud is first circulated in the hole to ensure that drill cuttings and borehole wall cavings have been removed prior to running the casing. The mill varnish is also removed from the surface of the casing to ensure that the cement will bond to the steel surface. Centralizers are used to ensure that the casing is placed in the center of the borehole. For under-reamed or washed out holes, bow spring centralizers are used. After the cement slurry is pumped down-hole, a lighter drilling mud follows. This results in the casing being under compression from a higher differential pressure on the outside of the casing. Thus when the cement sets and drilling continues, the casing will always have an elastic load on the cement-casing interface, which is essential for maintenance of the casing-cement bond and to prevent channeling or micro-annulus effects in the cemented annulus.

Many wells are subject to sustained casing pressures (SCP). The main cause is believed to be gas flow through the cement matrix. The cementing problems that could result in SCP include: (1) micro-annuli caused by casing contraction and/or expansion, (2) channels caused by improper mud removal prior to and during cementing, (3) loss circulation of cement into fractured formations during cementing, (4) flow after cementing by failure to maintain an overbalance pressure, (5) mud cake leaks, and (6) tensile cracks in cement caused by temperature and pressure cycles (Sweatman, 2006).

Mechanical Integrity Methods for Production/Injection Wells

In the United States, every production and/or injection well is required to demonstrate that it has sound mechanical integrity prior to it being placed on production/injection. Statutes and regulations have been implemented in every state to ensure that oil and natural gas operations are conducted in a safe and environmentally responsible fashion and wellbore integrity is maintained throughout their operating life-cycle. The regulatory requirements for injection wells as codified under 40 Code of Federal Regulations (CFR) Parts 144 through 148 require that the injection well demonstrate that it has both internal mechanical integrity (no leaks in tubing/packer or casing) and external mechanical integrity (all injected fluids are exiting the permitted injection interval and that there is no upward migration behind pipe due to channeling or a bad cement job/micro-annulus etc.). Leakage out of the production/injection zone into overlying USDWs could occur due to poorly cemented casing, casing failure, improperly plugged and abandoned wells or other artificial conduits, and natural fractures/faults etc. Cement that has properly set has very low permeability (approximately 10^{-2} m^2) and no significant flow of formation fluids can occur unless the cement has degraded or has not set properly. Casing failure could occur due to corrosion, erosion or improper design (Syed et al, 2010)

Internal Mechanical Integrity

Throughout the life of a producing well and during fracturing operations, the well conditions should be monitored on an ongoing basis to ensure integrity of the well and well equipment. Maximum and minimum allowable annular surface pressures should be assigned to all annuli (should be considered as “do not exceed” limits). Also, during initial drilling completion, positive pressure tests of the casing, tubing and inner annulus (between tubing and casing above the packer) are conducted. The required surface test pressure varies in each geologic area (but is generally at least 0.25 psi/foot of vertical depth to the top of the packer and the inner casing and may not exceed 70% of the minimum yield strength of the casing). A well has verified its internal mechanical integrity if the total pressure loss within the test period is less than 10% of the initial test pressure and the pressure is stable (thermal stabilization effects). Thermal stabilization can occur when liquids either expand or contract depending on temperature differential, causing questionable test results. Pre-loading an annulus or using fluids that are close to the same temperature as fluids in the well will help in mitigating this effect. The test fluid is generally an inert non-corrosive fluid/water or in some instances it could be a 50-50 mix of methanol/water, neat methanol or diesel (used in extremely cold environments for freeze protection). Factors to consider when conducting such tests (also referred to as MITIA or SAPT – Standard Annulus Pressure Test), is that when a liquid medium is used as the test fluid, the well may pass the MITIA, but later when it is on gas injection, there may be slow annulus pressure build-up (sustained casing pressure) that may not be easily detected over a long period of time. Other factors to consider for a successful MITIA for wells include proper packer selection (elastomers) and materials of construction for tubing and surface wellhead that will meet production and/or injection service requirements.

External Mechanical Integrity

There are several techniques that can be utilized to verify that production fluids are contained within the wellbore and that there is no upward flow behind the casing (due to chanelling/micro-annulus etc.) that can impact overlying USDWs. Some of these techniques are briefly discussed below (Syed et al, 2010).

Cement Evaluation

Acoustic cement logs are run to determine cement tops as well as the quality of the casing-cement and cement-formation bonds. Acoustic bond logs do not measure hydraulic seal, but instead measure the loss of acoustic energy as it propagates through casing. This loss of energy

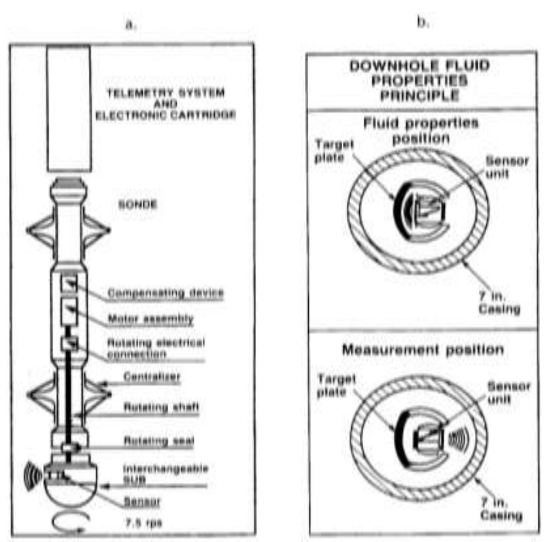


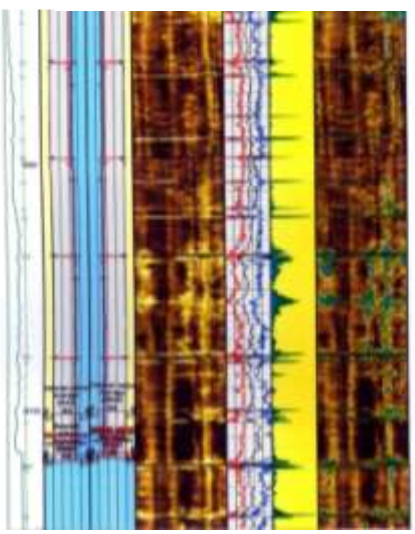
Figure 18. Ultrasonic Imager (a) tool design and (b) transducer position (Smolen, 1996)

is related to the fraction of the casing perimeter covered by cement. Two classes of sonic logging tools exist: (1) sonic (cement bond log/variable density log – CBL/VDL) or segmented bond tool (SBT) and (2) ultrasonic (ultrasonic imaging tool – USIT) (Boyd et al, 2006).

The Ultrasonic Imaging Tool (USIT) is basically a continuously rotating pulse echo type tool, and is an improvement over the Cement Evaluation Tool (CET) with nearly 100% coverage of the casing wall. The processing of the echo is, however, quite different from the CET. The USIT is shown schematically in Figure 18. The main working element is the rotating transducer indicated as "sensor" on the bottom of the tool string. The transducer rotates, emitting and receiving signals reflected back from the casing wall. The USIT tool is 3 3/8" in diameter and by changing the rotating transducer subassemblies can operate in casing sizes from 4 ½' to 13 3/8". The rotating transducer is shown in Figure 18(b). In the measurement position it is aimed toward the wall and in the fluid properties position it is aimed toward the target plate, with the fluid properties measured when going in the hole. The USIT presentation uses highly sophisticated computer processing and is color coded. It is very sensitive to the condition of the borehole and is preferably run along with a CBL to provide best overall picture of well integrity. An illustrative example of a USIT log is shown in Figure 19.

Acoustic impedance, Z, is defined as the product of the density (kg/m3) and acoustic velocity (m/sec) of a medium and is expressed in MRayl (10^6 kg/m^2 sec). A list of acoustic impedance values for common down-hole materials is given in Table 1Table 3.

Figure 19. Illustrative Example of USIT Log Run on Injection Well



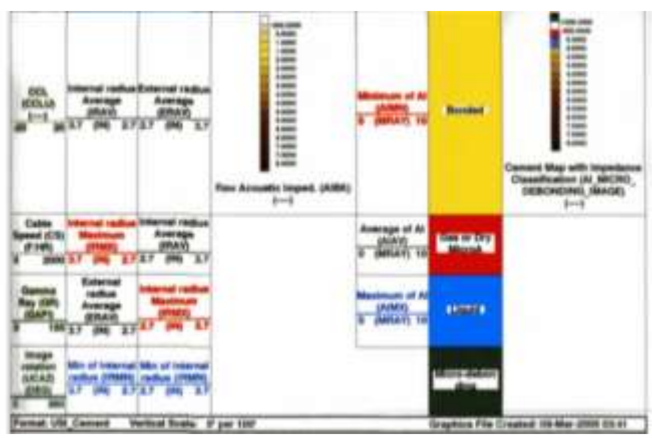


Table 3. Acoustic Properties of Materials (Smolen, 1996)

Material	Density (Kg/m^3)	Acoustic Velocity (m/sec)	Acoustic Impedance (MRayl)
Air	1.3 – 130	330	0.0004-0.04
Water	1000	1500	1.5
Drilling Fluids	1000-2000	1300-1800	1.5-3.0
Cement Slurries	1000-2000	1800-1500	1.8-3.0
Cement (Litefil)	1400	2200-2600	3.1-3.6
Cement (Class G)	1900	2700-3700	5.0-7.0
Limestone	2700	5500	17
Steel	7800	5900	46

The **Segmented Bond Tool (SBT)** is a radial cement bond device, which measures the quality of cement effectiveness, both vertically and laterally around the circumference of the casing. The SBT is designed to quantitatively measure six segments, 60^0 each around the pipe periphery and employs an array of high-frequency steered transducers which are mounted on six pads. Each of six motorized arms positions a transmitter and receiver against the casing wall. The SBT is usually run with a VDL (variable density log). A primary SBT presentation has (1) a correlation trace and (2) two attenuation traces that are an average of the 6 segmented measurements and a minimum attenuation trace representative of the 60^0 segment with the least attenuation. A separation of the two attenuation curves indicates a cement void on one side of the casing and a continuous wide separation over an extended depth interval infers the present of channeling within the cement sheath. An example Segmented Bond Tool (SBT) log run on an injection well is shown in Figure 20.

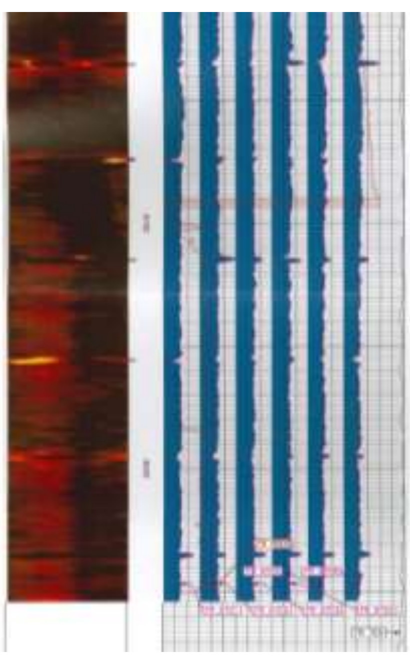


Figure 20. Example SBT Log

Figure 21. MIT Tool

Factors that Affect Cement Log Quality

There are many factors that affect the response of sonic logging tools. These factors include: micro-annulus, logging tool centralization, fast formation arrivals, use of lightweight cements and cement setting time (Boyd et al, 2006).

Micro-annulus. A micro-annulus is defined as a very small (approximately 0.01 to 0.1 mm) annular gap between the casing and the cement sheath. A micro-annulus can result in a misinterpretation of the CBL/VDL. Micro-annuli are caused by temperature, mud-cake deposits, pipe coatings and constraining forces. A common procedure is to pressure up the casing to approximately 1,000 to 1,500 psi and close the gap (if the cement job was good). Micro-annuli affect ultrasonic tools much less than the CBL/VDL and SBT (pads) in the presence of liquid in the gap with the opposite effect in the presence of gas.

Eccentralization. This may be an issue particularly in deviated and horizontal wells with the absence of cement on the low side and the distance between the casing and formation face is small.

Logging Tool Centralization. It is mandatory that the USIT and the CBL/VDL tools are well centralized. The SBT pads with their articulated arms are relatively unaffected by the centralization issue, although the CBL/VDL part of the tools is affected. Tool centralization can be checked in the log presentation.

Fast Formations. Formations with very high velocity and short transit time are called “fast formations”. Acoustic signals from anhydrites, low porosity limestone and dolomites often reach the receiver ahead of the pipe signal. Fast formations affect the CBL/VDLs and SBT logs but do not affect USIT interpretation.

Lightweight Cement. Cement evaluation relies on the contrast in the acoustic properties of the cement and liquid. The acoustic properties of lightweight cement (commonly used in areas of weak formation) are close to those of cement slurry making it difficult to distinguish between the two.

Cement Setting Time. This is an important consideration in CBL interpretation. If the bond log is run before the cement is fully set, a misinterpretation indicating poor bonding may result in an unnecessary squeeze operation. The hardening time of cement slurries depend on their type and formulation, the down-hole temperature profile and pressure conditions, and extent of drilling mud contamination. The U.S.EPA recommends a 72 hour waiting on cement (WOC) prior to logging UIC regulated wells, while the American Petroleum Institute (API) and the Alberta Energy and Utilities Board suggest a 48 hour WOC time (for oil and gas related production and injection wells). The ultrasonic cement analyzer (UCA) can be utilized to determine when to log and has shortened the WOC time.

To declare zonal annular isolation between two points behind casing, a minimum length of continuous good quality cement should exist. A recommendation of 33 feet of continuous good cement for the 7 inch casing and for 45 feet for 9 5/8 inch casing has been reported in a EPA publication, while oil industry service company recommendations for continuous good quality cement are 10 to 11 feet for 7 inch casing and 15 feet for 9 5/8 inch casing, to assure zonal isolation (Boyd et al, 2006).

Finally, it should be noted that even if cement quality logs indicate good bonding and zonal isolation, there may be annular communication resulting from reactions between the rock, cement and formation fluids in production wells.

Zone Isolation/Pressure Testing

Placement of the cement completely around the casing and at the proper height above the bottom of the drilled hole (cement top) is one of the primary factors in achieving successful zone isolation and integrity. It is good practice to pressure test the shoe after drilling out the cement shoe on the surface and intermediate/longstring casing strings and confirm zonal isolation at the shoe. This involves pressuring up inside the casing until the pressure at the shoe exceeds the maximum hydrostatic pressure expected at that point during subsequent drilling operations. Failure of cement around the shoe is usually due to contamination, either from the original drilling mud or from the displacement fluid and usually results from poor cementing techniques rather than poor quality cements since hard-set neat cement has sufficient strength to withstand pressure tests.

Multi-finger Caliper Surveys

Multi-finger caliper logs (multi-finger imaging tools - MIT) are used to detect very small changes to the internal surface condition of tubing from the impacts of corrosion and/or mechanical damage. The tool may be run through tubing to log casing deeper in the well. They are available in 24, 40 and 60 fingers or arms (tool diameters of 1.6875, 2.75 and up to 4.4 inches respectively) to suit varying casing/tubing sizes. The number of fingers increases with the diameter of the tool and when the tool is run in the hole, the fingers are closed to prevent damage. Tool deployment can be via slick-line, e-line, coiled tubing or down-hole tractors. The magnetic thickness tool (MTT) uses 12 miniature magnetic sensors, to investigate variations of metal thickness within down-hole tubular. Data from the multi-finger imaging and magnetic thickness tool can be combined to assess both the internal and external condition of the tubular including maximum cross-sectional wall loss, maximum penetration (pitting etc.) and reduction in wall thickness. A representative MIT and MTT tool is shown in Figure 21 and Figure 22, and an example multi-finger caliper survey run on an injection well is shown in Figure 23**.**

Figure 22. Magnetic Thickness Tool (MTT)

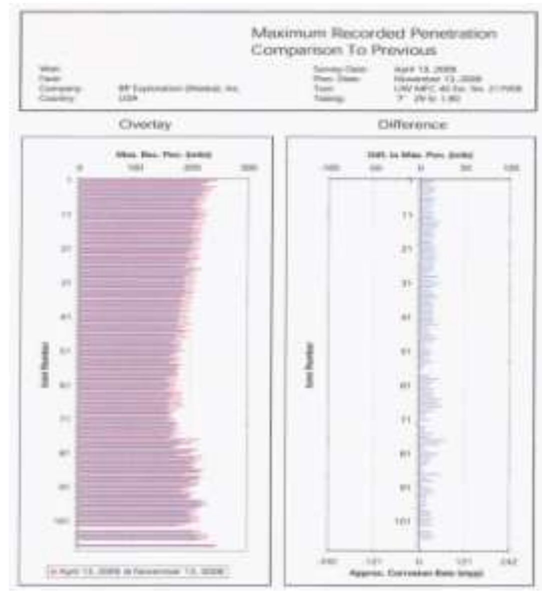


Figure 23. Example of Multi-Finger Caliper Survey

Oxygen Activation/Water Flow Log/Hydrolog

Oxygen Activation logs also referred to as a Water Flow Logs (WFL) or Hydrologs are used to detect water flow or channels behind casing in injection or production wells. The principle of water detection using Oxygen Activation can be explained as follows – when the neutron burst is generated by the tool, the oxygen associated with the up-flowing water is activated to an unstable nitrogen isotope having a half-life of 7.35 seconds (oxygen activation effect).When the nitrogen isotope returns to its native oxygen, gamma rays are emitted which may be detected by the near or far background count measurement. The times under consideration are long after the inelastic or capture gamma rays have ceased.

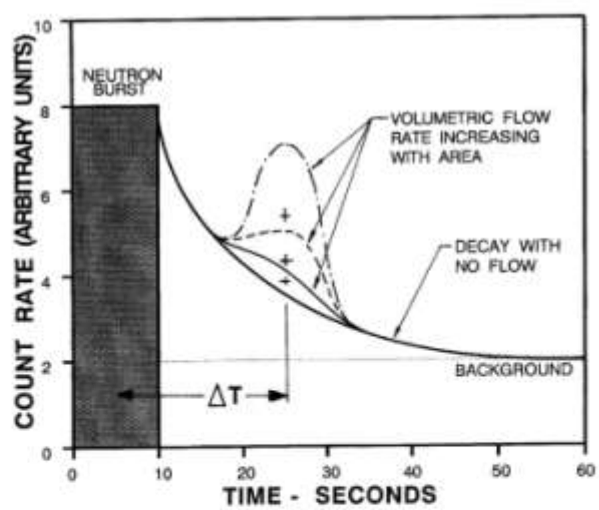


Figure 24. WFL Measurement Technique

The WFL is a dual burst TDT (thermal decay time) with a modified pulse sequence. Unlike a conventional TDT log, the OA/WFL needs to be run centralized. The operation of a WFL is shown in Figure 24. The neutron generator is turned on for either 2 or 10 seconds, then turned off. If no water flow is present, then the count rate decays as shown, reaching background after about one minute. If water flow is present, then the count rate decays as before, until the activated water moves adjacent to the detector. When that occurs, excess counts are observed. After the cloud of activated water passes, the counts return to the background decay curve. The data are recorded on three detectors, typically the near (N), far (F), and gamma ray (GR). Only one will be typically optimized to provide good data. While each burst and decay sequence takes about 1 minute, the data collected may be highly statistical, and therefore the burst and decay sequence will typically be repeated up to about 10 to 15 times. Figure 25 shows a WFL run on a well in Alaska.

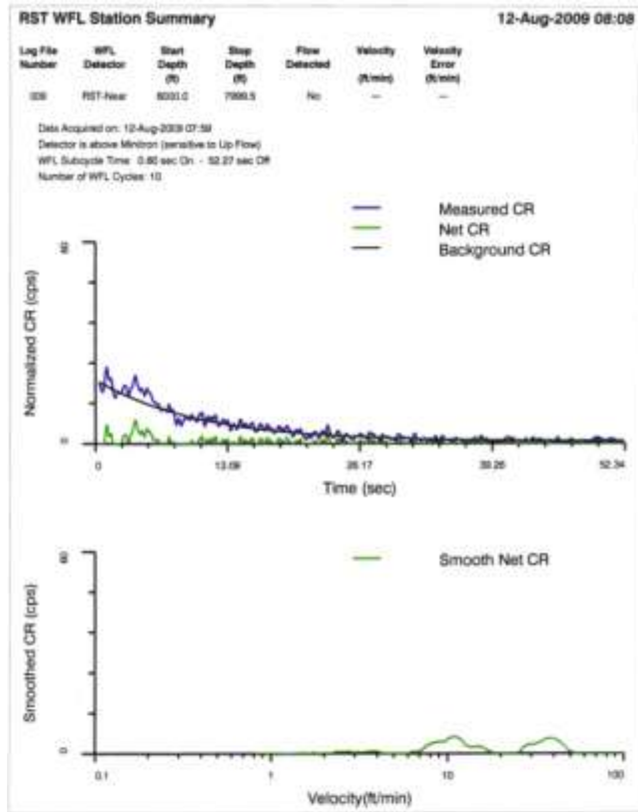


Figure 25. Example of WFL Log

Borax PNL Logs

Channel detection using temperature or noise logs is often ambiguous. In certain areas, radioactive (RA) tracers cannot be used either due to safety, environmental, or political reasons. As a result, a technique based on the higher capture cross section of boron has been developed in Alaska to locate channels behind pipe. The borax compound generally used is sodium tetra-borate penta-hydrate ($Na_2B_4O_7$), due to its high capture cross section, low cost, and ready availability. The mix rate used in Alaska is 7 pounds/barrel of warm seawater.
The Borax PNL technique involves comparing pulsed neutron log (PNL) passes run before and after pumping a solution of borax dissolved in warm water as a tracer. A PNL indicates a significant Sigma value when boron is present, so an overlay of log passes quickly indicates those areas within and adjacent to the wellbore where boron accumulates due to injection of the tracer. An illustrative example of a Borax-PNL log run in Alaska is shown in Figure 26.

Ultrasonic Leak Detection Logs

A new tool that has demonstrated success in the North Slope of Alaska in detecting leaks as small as 0.0024 gallons per minute (gpm) is the ultrasonic leak detection logging tool run on wire-line or on slick-line in memory mode (Julian et al, 2007). The tool is particularly useful where rig workovers are expensive as in remote locations, offshore or in Arctic regions. It can detect leaks through multiple strings because ultrasound is not significantly attenuated by gas, liquid, or steel. Other advantages include: (1) it can be run in high pressure wells in which it is difficult to maintain a pressure seal for the wireline, and (2) in memory mode a tandem multi-finger caliper and a leak detection log can be obtained in one run. Many injection wells were previously producers and therefore have gas-lift mandrels. MI gas consists of 35% methane, 20% each of ethane, propane, and carbon dioxide. MI gas is an excellent solvent and easily dissolves grease seals, o-rings, and elastomers. A schematic of the ultrasonic tool is shown in Figure 27.

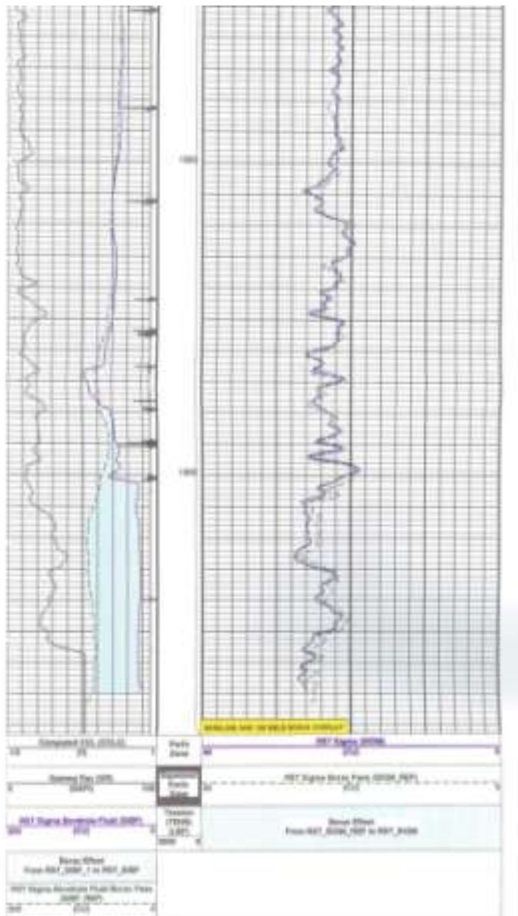


Figure 26. Example Borax-PNL Log

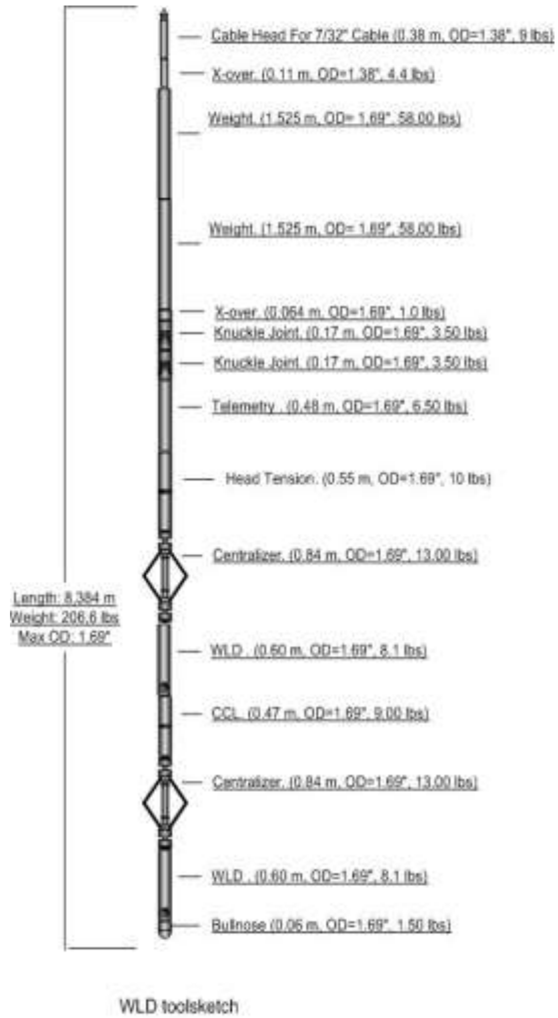


Figure 27. Ultrasonic Leak Detection Tool

Tree and Wellhead Integrity

The wellhead and tree are typically suitably engineered to withstand the normal operating pressures. For normal operations and during hydraulic fracturing operations, if the annulus between the production casing and the intermediate casing has not been cemented to the surface, the pressure in the annular space should be monitored and controlled. The intermediate casing annulus should be equipped with an appropriately sized and tested relief valve. The relief valve should be set so that the pressure exerted on the casing does not exceed the working pressure rating of the casing. Pressure exerted on equipment should not exceed the working pressure rating of the weakest component.

Wellhead seal tests need to be conducted to test the integrity of the sealing elements (including valve gates and seats) and confirm their ability to seal against well pressure. If abnormal annular pressures are noted, a re-pressure test of the wellhead system can help determine whether it is a surface wellhead leak as opposed to a subsurface leak.

Horizontal Wells

In general, horizontal wells have had great success in high-permeability reservoir and unconventional formations such as coal, chalk and shale. With the advancement of drilling and completion technologies, horizontal wells have become the industry standard for unconventional and tight formation gas reservoirs. Horizontal wells are commonly two to four times more expensive to drill and complete than offset vertical wells, yet are theoretically capable of up to three to five times the production. Environmental advantages with horizontal wells include a smaller drilling footprint with a reduction of well locations.

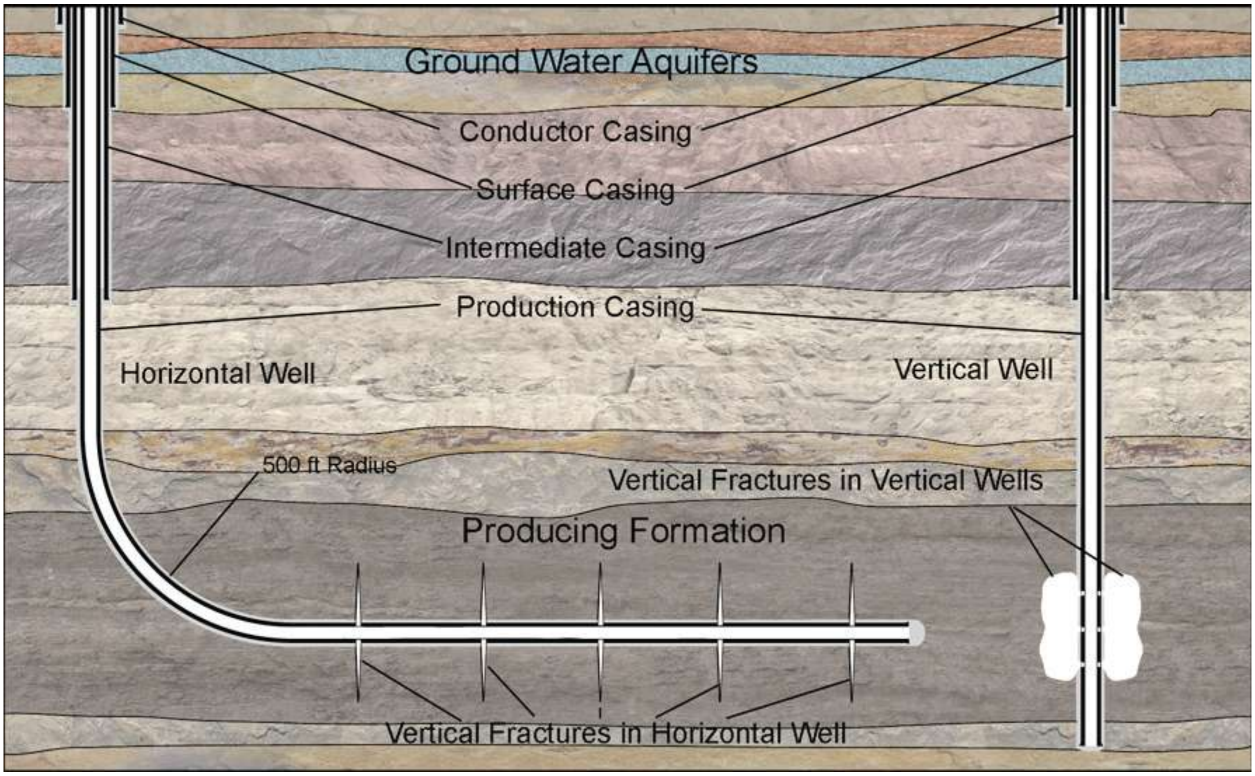
Horizontal wells are typically drilled vertically to a “kick-off” point where the drill bit is gradually turned from vertical to horizontal (see Figure 28). Horizontal wells use basically the same or similar equipment as vertical wells such as safety valves, packers and seal assemblies, flow control accessories, permanent down-hole gauges, artificial lift accessories etc. Tool manipulation is hydraulic or with reciprocation, while rotationally actuated tools should be used with caution. Intervention into the horizontal section requires coiled tubing, down-hole tractors or workstring.

Horizontal wells are completed with various degrees of annular isolation. Un-cemented or open- hole completions offer open access to fracture swarms, which may be plugged off or inaccessible if annulus is cemented. With open- hole or barefoot completions the most productive part of the interval has a better chance to be stimulated. Also, un-cemented completions avoid perforation-related stress cages that can result in a large extraneous source of treatment pressure drop. In this alternative, the producing portion of the well is the horizontal portion of the hole and it is entirely in the producing formation. In some instances, a short section of steel casing that runs up into the production casing, but not back to the surface, is installed. Alternatively, a slotted or pre-perforated steel casing may be installed in the open-hole section. These alternatives are generally called a “production liner” and are typically not cemented in place. In the case of an open-hole completion, the tail cement should extend above the top of the confining zone (the formation that limits the vertical growth of the fracture).

Cased and cemented horizontal completions offer greater control over fracture treatment placement and can be appropriate when dealing with relatively uniform rock. Where cemented completions are warranted, sand jet perforating is preferred as it removes formation material and thus avoids the stress cage related pressure drop.

Discontinuous multi-layer intervals such as stacked, fluvial-dominated sandstones are best completed with vertical wells in multi-stage treatments.

Figure 28. Example of a Horizontal and Vertical Well (API, 2009)



Hydraulic Fracturing

Hydraulic fracturing (HF) has been employed in the oil and gas industry since 1947 and allows the production of hydrocarbons from low permeability (tight) reservoirs economically. The process of hydraulic fracturing increases the exposed area of the producing formation, creating a high conductivity path that extends from the wellbore through a targeted hydrocarbon bearing formation for a significant distance, so that hydrocarbons and other fluids can flow more easily from the formation rock, into the fracture, and ultimately into the wellbore.

During HF, fluid is pumped into the production casing, through the perforations (or open hole), and into the targeted formation at high enough pressures to cause the rock to fracture; this is known as “breaking down” the formation. As high pressure fluid injection continues, the initiated fracture can continue to grow or propagate. The rate at which the fluid is pumped must be fast enough that the pressure necessary to propagate the fracture is maintained. This pressure is known as the propagation or extension pressure. As the fracture continues to propagate, a proppant, such as sand, is added to the fluid. The proppant allows the fracture to remain open when pumping is stopped (and the excess pressure is removed), allowing fluids to flow more readily through this higher permeability fracture. During the HF process, some of the fracturing fluid may leave the fracture and enter the untreated formation resulting in fluid leak-off. The fluid flows into the micropores or pore spaces of the formation or may intersect existing natural fractures in the formation.

In order to carry out the HF process, a fluid must be pumped into the well's production casing at high pressure. The production casing must be properly designed, installed and cemented so that it is capable of withstanding the pressure that it will be subjected to during the HF process. In some cases, a high pressure "frac string" may be used to pump the fluids, thereby not exposing the production casing to the high treatment pressures. Once the HF process is completed, the frac string is removed.

In the field, the HF process is called the "treatment" or "job" and consists of three stages:

- Pad – The pad is the first stage of the job where the fracture is initiated and is propagated in the formation. Another purpose of pad is to provide enough fluid volume within the fracture to compensate for fluid leak-off into the formation.
- Proppant Stages – Here proppants of varying concentrations are pumped. Most common proppant is ordinary sand sieved to a particular size. Other proppants include sintered bauxite and ceramic proppant.
- Displacement – Here the previous sand laden stage is displaced to a depth just above the perforations. This is done so that the proppant ends up within the fracture and not within the pipe. Sometimes called the flush, the displacement stage is where the last fluid is pumped into the well. The flush fluid could be plain water or the same fluid that was pumped earlier.

In wells with long producing intervals (both vertical and horizontal), the HF process can be done in a multi-stage process allowing for better control and monitoring of the HF process.

Post-Hydraulic Fracturing Monitoring

Prior to the HF treatment, the proppant, usually sand, may be "tagged" with a tracer. After the proppant has been pumped into the formation, a cased-hole log, capable of detecting the tracer, is run to confirm the proper placement of the proppant. A temperature survey in conjunction with the tracer log can also be run. Since the HF fluid is typically at ambient temperature at the surface and the formation temperature at the target depth is much higher, the formation is cooled considerably during the HF treatment showing which perforations accepted the fracturing fluid. The use of these techniques is declining with the advent of sophisticated computer modeling techniques for mapping fracture growth and geometry.

Refracturing

Refracturing of oil and gas wells (also known as fracture re-stimulations) are becoming increasing popular as this technique, under certain conditions, can restore or increase well productivity and ultimate hydrocarbon recovery. Re-stimulations can by-pass near well-bore damage and generate higher conductivity propped fractures resulting in more lateral extension and deeper penetration of the fractures, with ultimate higher hydrocarbon recovery.

More than 30% of fracturing treatments are performed in older wells, therefore, mechanical integrity of the tubular becomes critical in candidate selection for HF treatments. Surface casing vent flows must be checked and any indication of gas migration to the surface will result in the elimination in the well as a candidate.

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Case Study for Well Integrity over a Full Life Cycle

Lloyd H. Hetrick, PE, CSP
Newfield Exploration Company

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.

Abstract

This case study narrowly defines well integrity by one simple outcome: the prevention of vertical migration of fluids in order to protect drinking water resources. This paper should not be considered a stand alone document, rather an extension of the well design, construction, and surveillance practices which have already been addressed in this Workshop. A generic shale development well is presented, beginning with its basis of design, then construction, an operational phase, and ultimately its plug and abandonment. This chronology is illustrated by a series of well schematics, which are provided in Appendix A.

Regulations, industry standards, and best practices will be addressed, as will failure categories and relative failure rates at each phase of the well's life cycle. This case study will also raise relevant issues that may not have been fully discussed during this Workshop, such as the difference between exploration and development phases, development well economics, the potential for well integrity impacts from adjacent well activities, and a time line perspective.

Introduction

A brief process description for oil and gas projects might be helpful. Years before a well is drilled, significant geological and geophysical "G&G" work is performed to identify prospective areas. During this time, offset wells are studied to identify subsurface hazards that may be present in order to avoid or mitigate them. Once a prospect is defined mineral leases are acquired, additional G&G and reservoir analysis performed, and well design determined for specific drilling locations. The first group of wells drilled are called "exploratory" and intended to define the commercial value of the prospect. Exploratory wells require extra time to gather data on the quality of the reservoir and are also used to identify well construction efficiencies for the development phase. Once the project transitions from exploration to development, each well has to pass an economic hurdle to be drilled.

Regardless of being exploratory or development, responsible oil and gas companies have a strong business incentive to protect the environment, mineral reserves, and the well itself (1). It is almost always more difficult and costly to re-enter and repair a well than to address design deficiencies up front during construction.

This case study, although generic, is not unlike the Marcellus, Eagle Ford, and other unconventional plays with multiple hydrocarbon zones. Even though only one reservoir is the current development objective, additional reservoirs are candidates for future development.

This case study will address technical issues but cannot explore very many technical details due to a fifteen minute presentation limit. Accordingly, only the most relevant technical items such as failure modes will be included and even then, will be greatly abbreviated. For example, if corrosion is considered to be the primary failure category, the technical discussion will end there with no deeper look into the true root cause failure mode such as galvanic corrosion, sulfide stress cracking, etc.

Federal and State environmental laws protect underground sources of drinking water or "USDWs". This paper will use USDW synonymously with the term "protected water" and refers to an aquifer with less than 10,000 mg/l total dissolved solids or "TDS" (2).

State mineral law regulates the extraction and conservation of minerals unless on Federal BLM or BIA land, then Federal mineral laws apply. In either case, the regulatory agency that oversees mineral extraction is also the primary regulator for protecting USDWs during oil and gas exploration and production activities (3) (4).

Protected water and hydrocarbons have natural separation (5) in most situations. There are however, areas of the country where methane is routinely found to exist naturally in USDWs (6) (7) and has been associated with bubbles in rivers as early as the mid 1800s (8). There are also locations where methane vents to the surface via natural pathways having nothing to do with oil and gas extraction activities (9) (10). It has been estimated from a review of Pennsylvania regulatory records that over 95% of the complaints that oil and gas activities had contaminated private water wells were actually due to preexisting or other land use activities (11). These naturally occurring migrations are not limited to methane, as towns named Oil Springs, KY (12) Oil Springs, Ontario (13) and historical sites such as Seneca Oil Spring, NY (14) and Brine Springs, TX (15) all attest that oil and brine have been observed migrating to the surface dating back to the 1600's.

Basis of Design

A development well is drilled only if there is confidence that the estimated recoverable hydrocarbon reserves will provide an acceptable economic rate of return, given the cost to construct and operate the well. For an unconventional gas play, development wells tend to have generational designs where a group of wells will have a similar drilling, casing, cementing, perforating, and hydraulic fracturing design. Over time as more wells are drilled, experience provides opportunities to correct any design deficiencies, improve drilling efficiencies and well performance, therefore subsequent generations of wells are seldom designed exactly the same.

Individual wells, regardless of their generational status, receive detailed engineering analysis and planning which is communicated to the wellsite supervisor in the form of a written drilling and completion procedure. These well specific procedures are a planned sequence of activities which also incorporate regulatory compliance and industry best practices.

Well Construction - Drilling

A typical onshore well is spud with a conductor pipe that is driven, drilled, or augered into the ground by a construction crew or “spud rig” prior to the drilling rig’s arrival. This conductor pipe is a structural component that sometimes is not needed at all. Conductor pipe most often does not reach the top and does not penetrate the base of protected water; therefore it is not involved in protecting USDWs from vertical migration of fluids. Accordingly, failure categories for the conductor pipe will not be discussed.

The surface hole is drilled to a prescribed depth below the base of protected water. This depth is most often provided by the State Oil and Gas Regulator as in Oklahoma (16), or the State Environmental Protection Regulator as in Texas (17), or not specifically provided other than to protect all USDWs encountered as in Pennsylvania (18). In this latter situation, oil and gas operators typically research a Pennsylvania Groundwater Information System “PaGWIS” database and local water well driller’s records to generate a hydro geological map in order to determine depths of water that need to be protected.

The surface hole is not left open for more than a few hours while being drilled, cased, and then cemented back to surface. Those zones left open during this brief period are all USDWs, so vertical migration of fluids does not present a significant threat during surface hole drilling. The surface hole on our case study well is drilled in a few hours on the first day of the drilling operation.

The surface casing string is the primary barrier to prevent fluids from the wellbore from entering protected water as the well is being drilled to the next casing setting depth. Unlike the conductor pipe, surface casing is always required and is typically specified by regulation to be of “suitable and sufficient” quality (19) or “suitable for all drilling and operating conditions such as tension, burst, collapse” (20). For all casing strings, industry best practices provide extensive guidance on the selection of proper casing size, grade, weight, connections, plus procedures for field handling, inspection, and testing (21) (22) (23) (24) (25) (26) (27). For our case study well, the surface casing is “run” or installed in a few hours during day #1 of the drilling operation.

Failure categories for the surface casing and all other casing strings can be divided into the following five categories (28). It should be noted that two of these categories, mechanical and corrosion, may be secondary to cement failures where a failed cement sheath can lead to buckling or external corrosion that would not have otherwise occurred. Failure categories, their respective failure modes, relative failure rates, and remedial options will be discussed briefly:

- Materials – defects, tolerance busts, not getting the quality of pipe specified
- Connections – wrong connection selected for the service, improper makeup
- Wear and Handling – internal wear from drilling, external damage from handling
- Mechanical – tensile, burst, collapse, buckling, cyclic loading
- Corrosion – internal vs external; galvanic, CO_2, sulfide stress, hydrogen induced cracking

Materials defects are supplier dependent and can be managed by inspections and other supply chain quality control efforts. Connection problems are most often related to improper makeup and can be minimized by onsite supervision. Wear for the surface casing string is seldom a concern and occurs as a result of other problems encountered while drilling the well. Mechanical problems with the surface casing are very few when compared to deeper casing strings that are exposed to higher pressures and temperatures. External corrosion presents the highest failure category for surface casing. Remedies may include external coatings, cement squeezes, and cathodic protection systems.

The surface casing string's cement job provides the primary barrier against vertical migration of fluids into protected water for the entire life of the well. In the context of USDW protection, the importance of getting a good primary cement job on the surface casing string cannot be overstated. Remedial cementing options do not provide high success rates for zonal isolation and should be considered only for contingency purposes. Of all regulations for onshore wells, the rules for surface casing cementing contain the most stringent requirements for hole size vs casing size, centralization, cement quality, cement quantity, cement placement techniques, and quality assurance than for any other casing string (29). Failure to properly cement the surface casing string triggers both agency notification and corrective actions (30). The surface casing on our case study well is cemented on day #2 of the drilling operation.

There is a significant body of information published on cement selection and cementing best practices (31) (32) (33) (34). There is also a significant body of information available on cementing failure rates (35) (36). This Well Integrity Case Study will focus on those conditions which directly relate to zonal isolation for the protection of USDWs, briefly discussing three failure categories, with their respective modes and relative failure rates, and remedial options:

- Insufficient cement volume – underestimated annular volume, lost circulation
- Low bond strength – poor slurry design, poor management of hydrostatic head pressure
- Micro annulus, cracking, plastic deformation – thermal and pressure effects, cyclic loads

Cement failure rates are directly proportional to the ability to evaluate the top of and quality of the cement sheath. Cement tops can be identified by a temperature log, relative cement bond quality can be identified by a Cement Bond Log or CBL, while absolute cement bond quality requires a combination of logging, testing, and engineering analysis (37).

For all three cement failure categories, remedial options are not optimum and include pumping in from the top, spotting from the top via a small work string, or by perforating and squeezing. It should be noted that two of these three remedies, pumping in from the top and perforating and squeezing, might add new problems for zonal isolation if not properly executed.

There is a strong correlation between gas migration and uncemented or poorly cemented casing strings. There is also a strong correlation between external casing corrosion and the absence of a good cement sheath (35) (36).

After the surface casing has been successfully tested, the float collar, float shoe, and approximately 10’ of new formation are drilled. Another integrity test is then performed, a Formation Integrity Test or “FIT” which tests both the casing shoe and new formation together. This is not a leak-off test and does not test the limits of the shoe and formation, rather the FIT provides an assessment of the wellbore’s ability to withstand additional pressure in case of an influx of fluids and allows for safer drilling to the next casing point (38).

The next sections of well, which for this case study includes an intermediate and production casing section, are essentially a repeat of the surface casing section described above except that:

- The design depth for intermediate and production casing strings are not as comprehensively regulated (as for the surface casing depth) other than to provide safe drilling operations and to prevent the waste of minerals.
- The regulations concerning hole size vs casing size, centralization, cement quality, cement quantity, cement placement techniques, and quality assurance for intermediate and production casing strings are not as specific (as for the surface casing) other than to provide safe drilling operations and prevent the waste of minerals.

Although this case study well has been drilled, cased, and cemented over a 30 day period, the first two days are the most critical for zonal isolation of USDWs where the foundation for well integrity is determined.

Well Construction - Completion

Well completion is the where the production casing is perforated, the formation is hydraulically fractured, frac fluids are unloaded from the formation, and production operations commence. This is basically the well’s configuration for the rest of its life as it relates to protecting USDWs.

Prior to performing the hydraulic frac, the production casing is tested to anticipated frac pressure plus a safety factor, as is the frac tree and all the surface pumping equipment and lines. During the frac, all casing annuli are monitored, as is the injection rate, injection pressure, and slurry properties. If during the frac job, significant pressure is found on the intermediate casing annulus, or there is any indication of communication with the surface casing annulus, the frac job is shut down and not resumed until corrective actions are made that only the intended zone is subject to frac pressures.

Refracs are similar to original fracs as discussed above with the exception that a frac string or wellhead saver might be used to protect older production casing strings and wellheads from frac pressures. This is a case by case situation that requires additional testing and engineering analysis in order to protect both the well and USDWs during refrac operations.

As the well is produced, reservoir pressures tend to drop and liquid rates tend to rise, therefore devices for lifting liquids such as a tubing string with pumping or gas lift equipment becomes necessary. This internal configuration can have an impact on USDW protection and is addressed during the operations phase.

Well Operations

Prudent operators monitor all casing annuli on a regular basis to be able to detect sustained casing pressure or SCP. This condition could be caused by thermal expansion of annular fluids, packer or liner leaks, leaks into the annulus from inner tubing or casing strings, or from annular migration due to poor zonal isolation.

All states have rules for reporting and responding to the loss of well integrity which includes releases, non-thermal SCP, and other abnormal situations (39) as does the BLM (40) and best industry practices (41). The Commonwealth of Pennsylvania has new rules that require quarterly mechanical integrity testing and annual reporting for all operating wells (42).

Adjacent well operations may have an impact on mechanical integrity of our case study well. Hydraulic fracturing of a well near our case study well into a zone that is not protected, or not adequately protected for the conditions imposed can lead to unwanted well to well communication. This is currently a void where regulations and industry practices have not fully recognized that well integrity can become a neighborhood issue.

Well Plug and Abandonment "P&A"

Similar to well construction regulations and industry practices, well P&A also has comprehensive guidance to prevent vertical migration of fluids into USDWs. There is clear guidance for plug location, cement quantity, quality, placement techniques, testing, and reporting (43) (44) (45). Regulations may also specify that only approved cementing contractors perform plugging, require independent onsite supervision, and require post cement job certifications by both the operator and the cementing company.

There are also significant industry studies and best practices for well P&A (46) (47).

Failure studies have found that vertical migration issues in P&Aed wells are directly related to the original primary cement job during well construction. Those wells with gas migration to the surface prior to well P&A were likely to continue to have gas migration to the surface after P&A. Additionally, those wells plugged with bridge plugs and dump bailed cement on top were found to be more prone to leakage than wells plugged with cement that was circulated or squeezed in place (35) (36).

Conclusions

Well integrity and well construction are inextricably linked, regardless of the completion technique selected. Primary cementing is the critical step for preventing vertical migration of fluids during the well's productive life, and afterwards.

State and federal regulations address casing and cementing with prescriptive rules and reporting requirements, while industry employs a large body of technical studies and best practices. Five identified casing failure categories: materials, connections, wear / handling, mechanical, and corrosion are not as problematic for zonal isolation as three identified cementing failure categories: insufficient cement volume, low bond strength, and cement sheath damage.

For hydraulically fractured completions, significant bodies of industry technical information and best practices have been published. State and federal regulations address hydraulic fracturing with rules and reporting requirements which are continuously adapting to keep pace with technology advancements (48).

Adjacent wells and the potential for unwanted communication during hydraulic fracturing is a concern. State and federal regulations are largely silent on this issue, as are industry studies and best practices.

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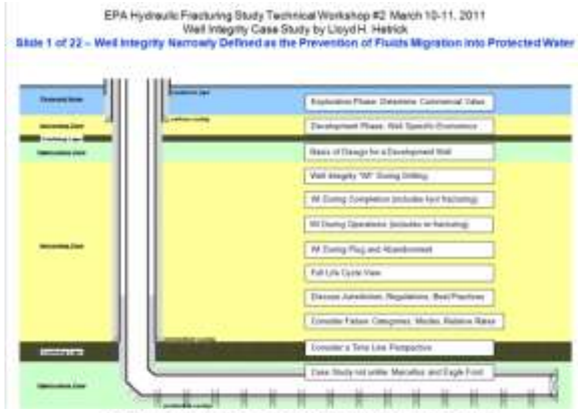
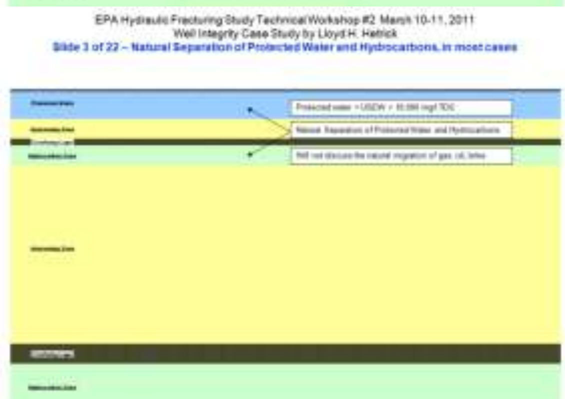
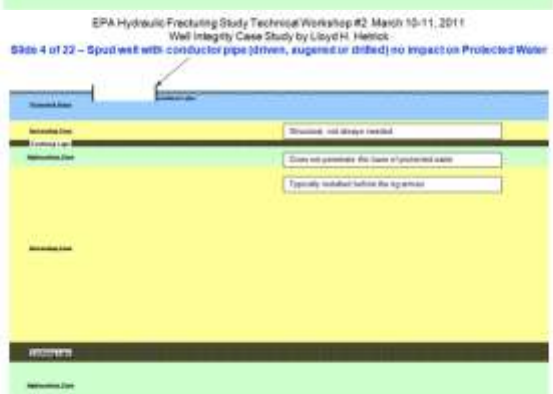
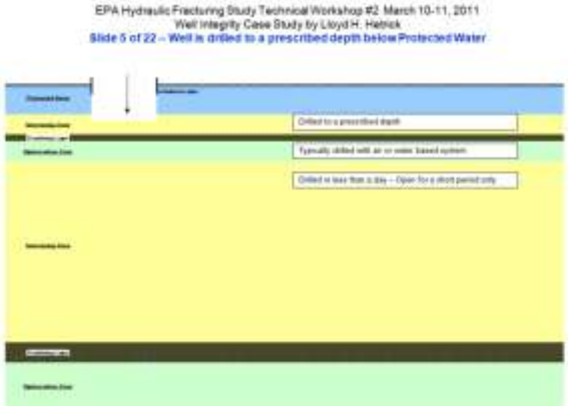
Appendix A – PowerPoint Illustration for this Well Integrity Case Study – Slides 1 through 4

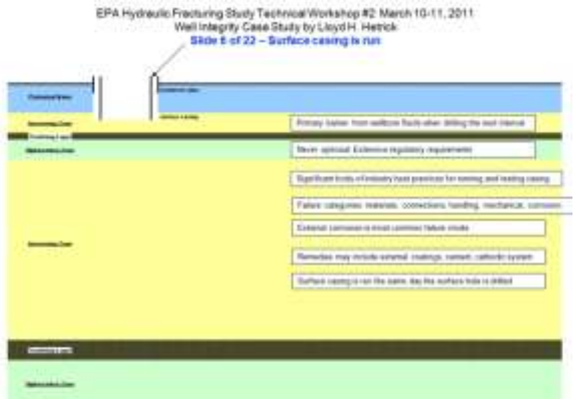


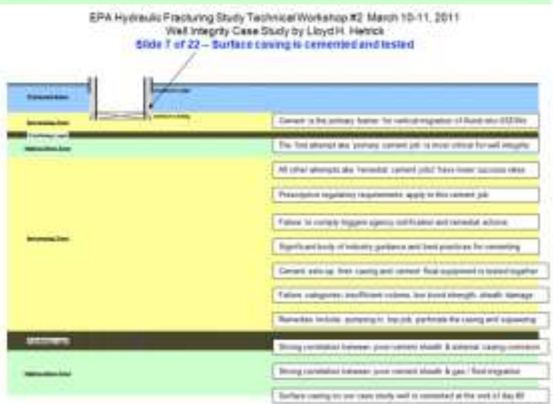




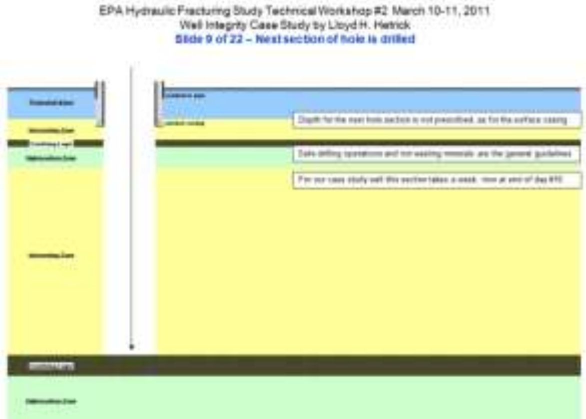
Appendix A – PowerPoint Illustration for this Well Integrity Case Study – Slides 5 through 8

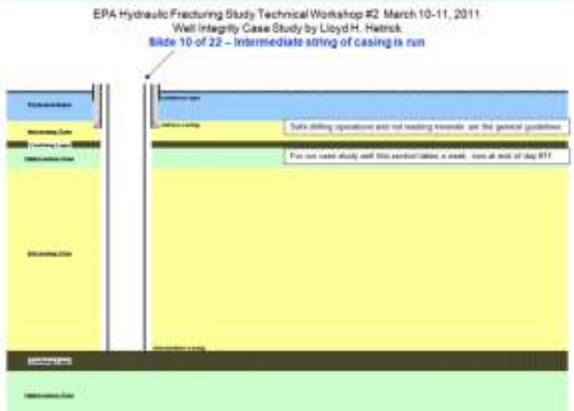


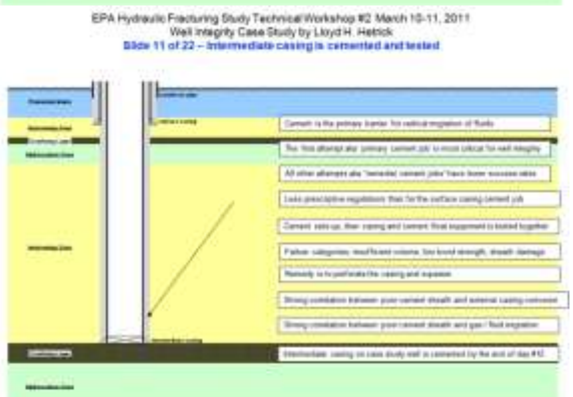


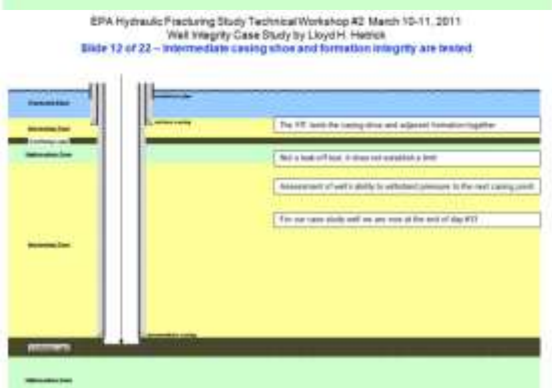


<u>Appendix A</u> – PowerPoint Illustration for this Well Integrity Case Study – Slides 9 through 12

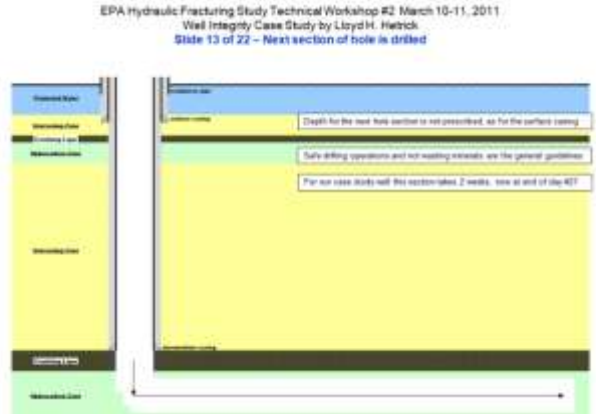


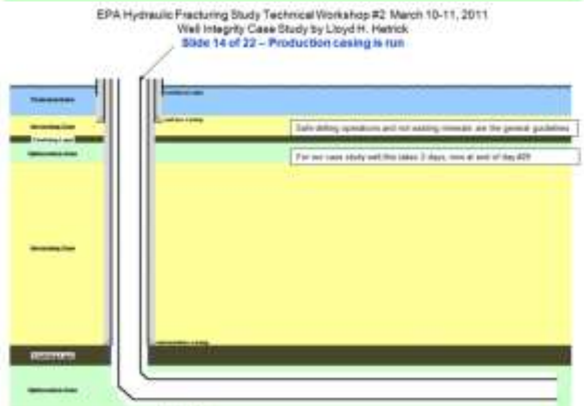


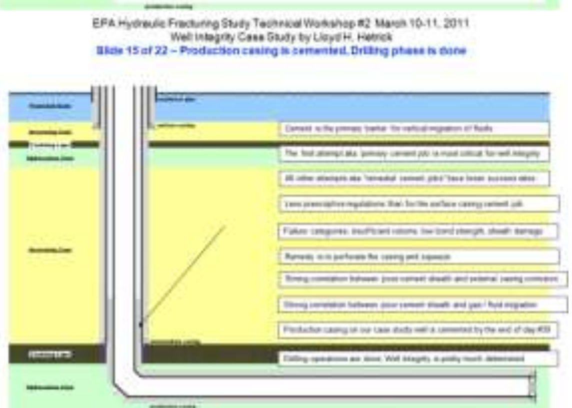


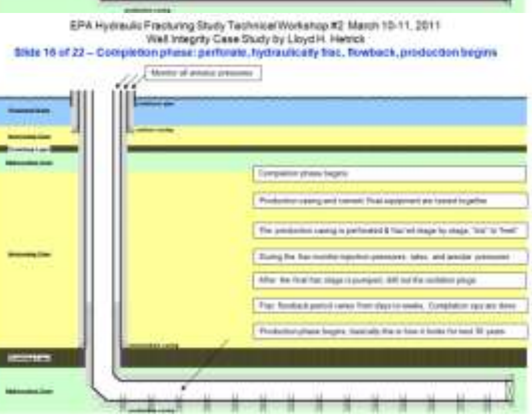


Appendix A – PowerPoint Illustration for this Well Integrity Case Study – Slides 13 through 16

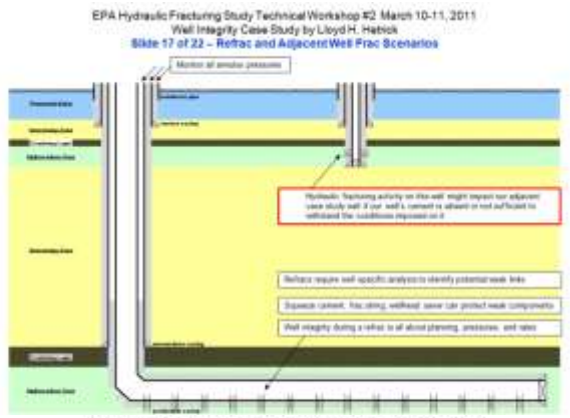


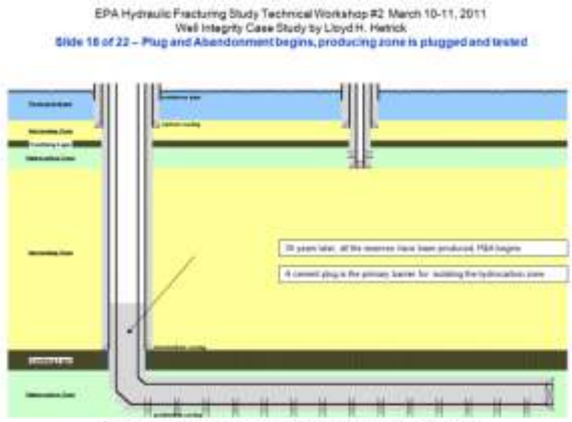


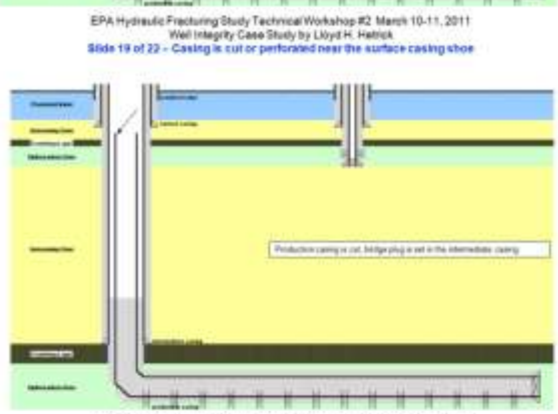


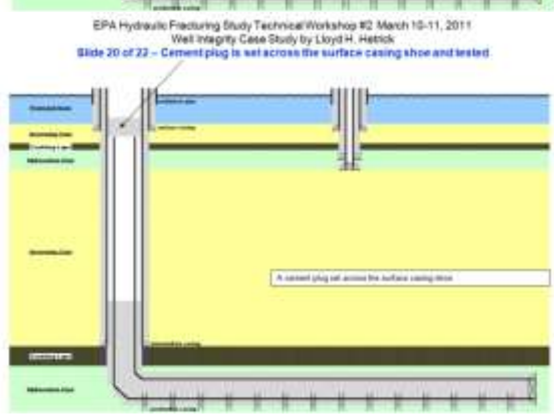


Appendix A – PowerPoint Illustration for this Well Integrity Case Study – Slides 17 through 20

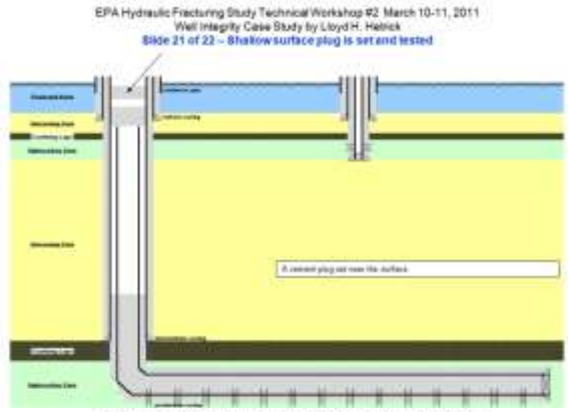


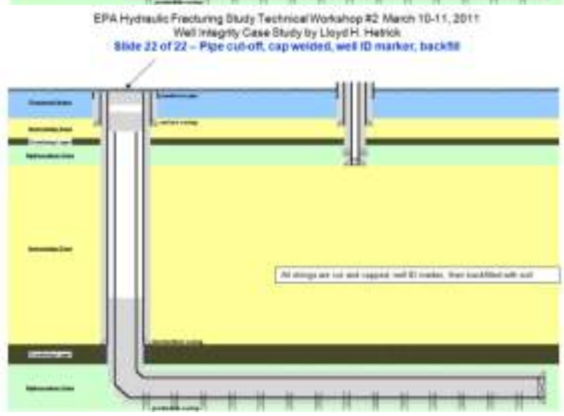






<u>Appendix A</u> – PowerPoint Illustration for this Well Integrity Case Study – Slides 21 through 22





Risks to Drinking Water from Oil and Gas Wellbore Construction and Integrity: Case Studies and Lessons Learned

Briana Mordick
Natural Resources Defense Council

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.

Introduction

Numerous cases of known or suspected drinking water contamination across the country have been linked to oil and gas production. This paper will examine various published reports from two such cases and discuss the potential roles of wellbore construction and integrity and hydraulic fracturing in the resultant drinking water contamination.

Case Study #1: Bainbridge Township, Geauga County, Ohio

Incident Summary

On December 15th, 2007, an explosion was reported in the home at 17975 English Drive, Bainbridge Township, Geauga County, Ohio. Early investigations determined that methane was entering homes in the vicinity of the explosion through domestic water wells. The Ohio Department of Natural Resources, Division of Mineral Resources Management (DMRM) inspected local gas wells to identify the source of the gas. When inspectors arrived at the English No. 1 gas well owned by Ohio Valley Energy Systems Corp (OVESC), representatives from OVESC were on location examining the well and discussing remedial cementing operations. OVESC proactively assumed responsibility for the incident without waiting for a completion of the investigation by DMRM and initiated corrective action. In the weeks following the explosion, DMRM initiated a monitoring program for methane in wells and homes and to monitor the response of wells to corrective action at the English No. 1 well. DMRM performed remedial work on affected water wells and provided in-home methane monitoring systems and replacement sources of drinking water for affected homes (Ohio DNR DMRM, 2008).

Simplified Stratigraphy at the Location of the English No. 1 Well

The OVESC English No. 1 well was drilled to a total depth of 3,926'. The formations encountered during drilling, listed in order of increasing depth, are as follows (Ohio DNR DMRM, 2008):

- Unconsolidated glacial till. Less than 88' thick
- Pennsylvanian and Mississippian aged interbedded sandstone and shale comprising the drinking water aquifer: Sharon Conglomerate, Cuyahoga Formation, Berea Sandstone. The Berea Sandstone has sometimes been noted to contain low-pressure natural gas. Approximately 200' thick
- Devonian aged Ohio Shale. Contains noncommercial quantities of low-pressure natural gas. Approximately 1800 feet thick

- Devonian and Silurian aged “Big Lime”/Lockport Dolomite limestone and evaporate deposits. Contains the Oriskany Sandstone and “Newburg” Dolomite members, which are porous, permeable, brine-bearing zones which sometimes locally contain noncommercial quantities of natural gas. Approximately 1600’ thick
- Thin interbedded shale and limestone partly comprising the seal for the gas-bearing target reservoir. Contains the Packer Shell, a typically impermeable limestone but which can be locally faulted or fractured near structural features. Approximately 100’ thick
- Low porosity and permeability Clinton Sandstone. Target formation containing commercial quantities of natural gas. Approximately 200’ thick

<u>Sequence of Events Leading to Natural Gas Invasion into Drinking Water Aquifers</u>
OVESC spud the English No. 1 well on October 18th, 2007. Conductor casing was installed to a depth of 88 feet, through glacial till and into bedrock. The well was drilled through the groundwater aquifers and surface casing was set at 263 feet and cemented to surface. Drilling continued until the total depth of the well, 3,926 feet, was reached on October 26th. An open-hole logging run was attempted but the logging tool bridged out at 3,658 feet, the depth of the Packer Shell, due to an apparent filter cake build up. The logging tool could not be moved below the bridge and open-hole logs were not obtained. OVESC proceeded to set 4-1/2” production casing. Casing was run into the hole and became stuck at 3,659 feet, the depth of the Packer Shell. The casing was washed down to 3,873 feet, became differentially hung, and could not be lowered further. OVESC then proceeded to cement the production casing. Prior to cementing, circulation of the wellbore was established but was subsequently lost during the cementing operation and could not be re-established. The cementing operation was concluded and, due to the lost circulation event, a cement bond log was run to establish the top of cement (TOC). (Ohio DNR DMRM, 2008; Bair et al, 2010)

Based on the cement job design, TOC should have been 700-800 feet above the top of the Clinton formation. The cement bond log revealed TOC to be at 3,640 feet, the depth of the Packer Shell. This finding and the previous drilling, logging, and casing problems suggest the Packer Shell thieved a large quantity of cement due to the presence of localized fracturing. Despite the inadequate primary cement job, OVESC continued to complete the well. The well was perforated from 3720-3740 feet, leaving only approximately 80 feet of cement covering the Clinton between the top perf and the TOC/open annulus, and the planned hydraulic fracture treatment proceeded on November 13th. The original frac design called for 105,000 gallons of water and 600 sacks of proppant. After pumping less than half the planned fluid and proppant, fluid circulated out of the open valve on surface-production casing annulus. Pump pressure and rate were reduced, 4000 gallons of fresh water was pumped to flush and recover sand, and the frac job was discontinued. (Ohio DNR DMRM, 2008; Bair et al, 2010)
In the three days following the well completion, most of the frac fluid was recovered and pressure on the surface-production casing was recorded. The pressure increased each day and stabilized at 320 psi on the third day and gas was periodically blown off to reduce pressure. Construction was completed and the well was shut in for the next 31 days. (Ohio DNR DMRM, 2008; Bair et al, 2010)

While the well was shut in, gas from the Clinton, Newburg, and Ohio Shale formations migrated into the uncemented annular space behind the production casing and caused the annulus to become overpressured, reaching a maximum recorded pressure of 360 psi. This gas then migrated from the high-pressure annulus, through fractures, into the shallow low-pressure aquifer and subsequently into domestic water wells, culminating in the explosion on English Drive. (Ohio DNR DMRM, 2008; Bair et al, 2010)

Remedial Action

OVESC performed two remedial cement jobs, one to seal the annulus from the current TOC to above the Newburg formation and one to seal the remaining open annulus to surface. Small amounts of gas were still detected in the annulus and a segmented bond log was run to determine the source. The bond log showed channeling of the cement from 550 feet to surface, which was allowing shallow Ohio Shale gas to enter the annulus. A good to excellent bond was measured below that depth. (Ohio DNR DMRM, 2008; Bair et al, 2010)

Primary Causes of Gas Invasion into Drinking Water Aquifers

1. **Poor Primary Cement Job**: The poor primary cement job left the shallow Newburg Dolomite and Ohio Shale gas-bearing zones open to the annulus behind the production casing, allowing high-pressure gas to migrate into the annulus.
2. **Decision to Hydraulically Fracture the Well Despite the Poor Cement Job**: Circulation of fluid and oil in the surface-production casing annulus during hydraulic fracturing indicates that the fractures grew "out-of-zone" and allowed the frac to communicate directly with the wellbore. The frac likely compromised the 80 feet of cement between the top perf and the open annulus, causing a loss of cement bond between the formation and production casing. This likely allowed Clinton gas to also migrate into the annulus behind the production casing.
3. **Shutting in the Well for 31 Days**: The decision to shut in the surface-production casing annulus for 31 days allowed the annulus to become over-pressured and gas to migrate from the high-pressure annulus, through fractures, to the groundwater aquifer and eventually into domestic water wells. (Ohio DNR DMRM, 2008; Bair et al, 2010)

Areas of Dispute

Subsequent to the well contamination incident, 42 property owners brought a suit against OVESC and six other parties involved in the operations at the English No. 1 well. (Bair et al, 2010). As part of the suit, the attorneys for the plaintiffs contracted Eckstein & Associates (E&A), a geological engineering firm, to review the causes of the incident. This subsequent report differed from the DMRM assessment in several areas. Consequently, DMRM convened a panel of experts to review the findings of Eckstein & Associates. The four main areas of dispute are as follows:

1. Was the over-pressurization of the annulus of sufficient magnitude to induce fractures in the geologic formations exposed in the uncemented annulus?

    a. The E&A report concluded that the pressures were indeed sufficient to create fractures in the Ohio Shale and portions of the “Big Lime”, providing migration pathways for deep gas. (Eckstein, 2009)
    b. The DMRM Expert Panel concluded that the pressures may have been sufficient to create fractures in the Ohio Shale but that any fractures created would be shallow, oriented horizontally, and of limited extent, and at most would temporarily augment transport along natural fracture networks. (Bair et al, 2010)
2. If the over-pressurization of the annulus did induce fractures, could they become permanent migration pathways for deep gas to reach groundwater?
    a. The E&A report concluded that the “deep- and far-reaching fractures” created by the over-pressurization of the annulus will serve as long-term migration pathways for methane to groundwater. Supporting evidence offered includes data for wells in the affected area showing that methane concentrations have remained high or increased over time. (Eckstein, 2009)
    b. The DMRM Expert Panel report concluded that any induced fractures would be shallow and of limited vertical, aerial, and temporal extent and consequently would not create long-term migration pathways for gas to groundwater. Supporting evidence offered includes data showing that the gas plume is dissipating upward and gas pressures in affected wells are decreasing. (Bair et al, 2010)
3. Can methane concentrations in domestic water wells be used to delineate such fracture networks?
    a. The E&A report concluded that the presence of methane in water wells was sufficient evidence for the presence of induced fractures, and therefore could be used to map or delineate such fracture networks. (Eckstein, 2009)
    b. The DMRM Expert Panel report concluded that the presence of methane alone, in the absence of other corroborating evidence, was not sufficient to delineate such fracture networks. They determined that other factors are in part responsible for the patterns of methane concentrations measured in domestic water wells over time. (Bair et al, 2010)
4. What is the nature and origin of the presence of black particulate matter in some domestic water wells?
    a. Following the English No. 1 well incident, some residential water wells began yielding black particulate matter. Chemical analysis showed that the particles consist of heavy metals, including lead and copper. The E&A report concluded that the particulate matter was entrained in the gas leaking from the well, with the likely source being the Ohio Shale. (Eckstein, 2009)

b. The DMRM report concluded that the particulate matter was not widespread and that it could not be determined whether it was created by the released methane or by natural processes. (Bair et al, 2010)

Case Study #2: Mamm Creek Field, Garfield County, Colorado

Incident Summary and Studies Considered for Review

In 2004, citizens notified the Colorado Oil and Gas Conservation Commission (COGCC) of the presence of gas bubbling in the West Divide Creek, Garfield County, CO, near the Mamm Creek Gas Field. Subsequent investigations identified the gas as thermogenic gas from the Williams Fork (Mesaverde) Formation, which is the primary gas-bearing target in the Mamm Creek Field. Water testing also detected the presence of BTEX compounds above regulated limits. It was determined that the gas and other contaminants were leaking from a nearby wellbore which had been improperly cemented, Encana's Schwartz #2-15B. Fines from this incident were used to fund a study to determine the vulnerability of groundwater and surface water to impacts from natural gas exploration and other human activities in Garfield County, CO near the Mamm Creek Natural Gas Field.

The Phase I study, performed by URS Corporation, compiled and evaluated existing data on water wells, gas wells, and water quality, and also included a limited amount of new field work (URS, 2006). The Phase II Study, performed by S.S. Papadopulos and Associates, focused on two field sampling tasks:

1. Water quality, gas composition, and methane stable isotope samples were obtained for wells which previously had compounds of concern above regulated limits or had sodium-chloride (Na-Cl) concentrations which suggested mixing with deeper brine/saline water.
2. Produced water and gas samples were taken from gas wells near the domestic water wells which had water and/or gas chemistry which may have been influenced by deeper formations, either by natural processes or through gas drilling activities (Papadopulos, 2008)

Subsequently, Dr. Geoffrey Thyne provided summaries and reviews of the Phase I and Phase II studies (Thyne, 2008). Dr. Thyne's conclusions were in turn reviewed by S.S. Papdopulous and Associates (Papadopulos, 2009), Bill Barrett Corporation (Donato et al, 2009), and Dr. Anthony Gorody of Universal Geoscience Consulting, Inc (Gorody, 2009).

Beginning in 2009 and completed in 2011, the United States Geological Survey (USGS), in cooperation with the Colorado Department of Public Health, undertook a study to determine the sources and sinks of nitrate and methane in domestic water wells screened in the shallow Wasatch formation in Garfield County (McMahon et al, 2011).

The following findings were generally consistent throughout all the studies considered:

1. Some domestic water wells had increased concentrations of methane, relative to background
    a. Both biogenic and thermogenic methane were detected
2. Some domestic water wells had concentrations of fluoride, selenium, nitrate, and/or arsenic which exceeded health-based standards
    a. Fluoride and selenium concentrations do not appear to be related to oil and gas activity
    b. Nitrate concentrations are most likely related to agricultural activity, septic system effluent, and/or animal waste
3. Some domestic water wells had concentrations of chloride, iron, manganese, and/or total dissolved solids (TDS) which exceeded aesthetic-based standards
    a. High chloride and TDS concentrations indicate the mixing or interaction of shallow groundwater with deeper formation water. (URS, 2006; Papadopulos, 2008; Thyne, 2008; McMahon et al, 2011)

Several areas of dispute arose between the various studies, including:
1. Evidence for a temporal correlation of methane and chloride contamination and natural gas activity
2. The nature and origin of methane in domestic water wells
3. The primary mechanism for deep Wasatch or Mesaverde formation water to mix with shallow groundwater (URS, 2006; Papadopulos, 2008; Thyne, 2008; Donato et al, 2009; Gorody, 2009; Papadopulos, 2009; McMahon et al, 2011)

<u>Areas of Dispute</u>

Evidence for a temporal correlation of methane and chloride contamination and natural gas activity

In his review of the Phase I and II studies, Dr. Thyne observed that methane concentrations and the number of wells with elevated chloride concentrations increased with time and were correlated to the increasing number of gas wells with time. (Thyne, 2008) Papadopulos and Associates, Bill Barrett Corporation, and Dr. Gorody disputed this claim and stated that there is no statistically significant increase in methane or chloride concentrations with time (Donato et al, 2009; Gorody, 2009; Papadopulos, 2009).

The nature and origin of methane in domestic water wells

The Phase I study found the presence of methane of biogenic, thermogenic, and unknown origin in the water samples. Most samples that had elevated concentrations of methane contained biogenic methane. The study indicates that biogenic methane can be formed by various processes but does not offer a hypothesis for how the methane came to be present in groundwater and domestic water wells. The implication, however, is that presence of biogenic methane in domestic water wells is not related to oil and gas development. A smaller number of samples contained thermogenic methane. In the area near the West Divide Creek seep, the origin of the methane is concluded to be from the leaking gas well which caused the seep. Some of the highest methane concentrations were detected in the southeastern portion of the study area. Although there had been little gas development activity in the area, there were several old wellbores that records indicate may not have been properly plugged and abandoned. The study concluded that the presence of thermogenic methane in water samples could result from either migration along natural pathways, such as faults, or from natural gas drilling, completion, or production activities or improperly abandoned wells. The researchers concluded that more data would be necessary to conclusively determine which migration pathway was responsible in each instance. The origin of the unknown methane types could not be determined and may have resulted from mixing of different sources. (URS, 2006)

The Phase II study also found the presence of methane of both biogenic and thermogenic origin in domestic water wells. Although most samples had isotopic compositions which indicated a thermogenic origin, researchers determined that most samples were in fact biogenic in origin. The conclusion was that the majority of samples which appeared to have a thermogenic isotopic signature had undergone a "biogenic methane oxidation shift". This is a process by which gas that is biogenic in origin undergoes oxidation, leaving the remaining fraction of methane with an isotopic signature that appears to be thermogenic but is in fact biogenic. As with Phase I, the researchers did not offer a hypothesis for how the biogenic methane came to be present in domestic water wells. Again, the implication is that the presence of biogenic methane in domestic water wells is not related to oil and gas development. A smaller number of samples contained methane that the researchers believed to be truly thermogenic in origin. Two hypotheses were offered to explain the nature and origin of these samples:

1. The samples may be derived from deeper gas-bearing formations, either tight sands gas or coalbed methane gas
2. The samples may represent some mixture between biogenic and thermogenic gas

For those samples which the study determined to be truly thermogenic in origin, and not the product of oxidation of biogenic methane, the researchers suggest that two mechanisms may be responsible: migration along natural faults and fractures or gas exploration and production. The study concluded that distinguishing between the two is not possible with the current data. (Papadopulos, 2008)

In his review of the Phase I and Phase II studies, Dr. Thyne also agreed that the samples contained methane which appeared to be of both biogenic and thermogenic origin. However, unlike the previous researchers, Dr. Thyne concluded that the majority of samples were thermogenic in origin. Dr. Thyne rejected the conclusion of the Phase II study that many of the samples with thermogenic isotopic signatures were in fact biogenic methane which had been oxidized. For those samples with isotopic values indicating biogenic origin, Dr. Thyne noted that their origin was microbial CO_2 reduction, in which CO_2 is converted to methane by microbial processes. Dr. Thyne concluded that the origin of this CO_2 was thermogenic CO_2 from the Williams Fork (Mesaverde) Formation. Consequently, the methane produced by this CO_2 would also be considered thermogenic in origin. Due to this finding that the majority of samples were thermogenic in origin, Dr. Thyne concluded that gas development activities had impacted groundwater. (Thyne, 2008) Papadopulos and Associates disputed these conclusions and found no basis to change the conclusions from their original report (Papadopulos, 2009).

The USGS study also sampled methane which appeared to be of both biogenic and thermogenic origin. The USGS study used a more diverse geochemical data set than previous studies to determine the nature and sources of the methane. Samples with the highest concentrations of methane appeared to be biogenic in origin. These samples also contained high concentrations of helium-4 and the co-occurrence implies that the methane was derived from a deep source rather than being generated in-situ in domestic water wells. Researchers concluded that one source for this deep biogenic methane could be the deep Wasatch Formation. Some samples also contained methane which appeared to be thermogenic in origin. Researchers determined that some of these samples may have contained biogenic methane which had undergone oxidation while other samples contained methane which was truly thermogenic in origin. The source of this thermogenic gas was most likely the Mesaverde (Williams Fork) Formation. The study concluded that two migration pathways were possible for both the deep biogenic and thermogenic gas: natural faults or fractures or the uncemented annular space in gas wells. (McMahon, et al, 2011)

The primary mechanism for deep Wasatch or Mesaverde formation water to mix with shallow groundwater

All four studies concluded that the geochemistry of some water samples may indicate mixing between shallow groundwater and deeper water. All four studies also suggested that either natural faults or fractures or gas wellbores could provide pathways for deep water to reach shallow water, however there was some disagreement between the studies on which of these pathways was most likely. (URS, 2006; Papadopulos, 2008; Thyne, 2008; McMahon et al, 2011)

The URS study concluded that the cause of mixing could not be determined and could have been the result of either natural pathways or gas development activities (URS, 2006). The Papadopulos and Associates study also concluded that natural pathways, wellbores, or hydraulic fractures may be possible migration pathways for deeper fluids but stated that the samples with geochemical signatures indicating mixing were from wells in areas with only modest gas development activity and therefore it was not possible to distinguish between natural and manmade impacts (Papadopulos, 2008). In his review of the Phase I and Phase II study, Dr. Thyne concluded that the number of domestic water wells with elevated chloride concentrations was increasing over time and correlated to the number of gas wells drilled, and the that source of the chloride was produced water (Thyne, 2008). The USGS study concluded that both natural fractures and wellbores were likely migration pathways for deeper formation water to reach shallow groundwater. They also determined that Mesaverde formation water was an important source of chloride in some wells even when the actual fraction of Mesaverde water in the sample was small (McMahon et al, 2011).

Key Observations

Despite the areas of dispute discussed above, some key observations and conclusions emerged from the studies. (URS, 2006; Papadopulos, 2008; Thyne, 2008; McMahon et al, 2011)

- Some domestic water samples contain methane and deep formation water which may have migrated to water wells through either natural pathways or gas wellbores or both.
- The study area is naturally faulted and fractured. Fault and fracture density increases near structural features, such as the Divide Creek Anticline.
- Regulations were updated in 2004 to require that all new wells have surface casing set below the lowest USDW and cemented to surface and production casing cemented to 500’ above the top of gas in the Mesaverde (Williams Fork) Formation. There is no requirement to cement over the deep Wasatch Formation. Older wells may have been constructed using different standards and may not have been properly abandoned.
- Gas production wells with persistent or recurring elevated bradenhead pressures have been identified near structural features.
- Domestic water wells with elevated methane and chloride concentrations are often coincident with structural features.
- Natural fractures and faults may provide migration pathways for gas and fluids, both to groundwater and to the uncemented annular space of wellbores. Fractures and faults may also cause complications in well drilling, construction, and completion and result in well integrity problems.

Challenges

Both these case studies and others around the country face challenges in determining causality of water contamination. One of the most significant challenges is the fact that in many oil and gas development fields, a systematic and comprehensive assessment of baseline water quality predating oil and gas development does not exist. When water contamination related to oil and gas development is suspected, investigators must piece together baseline water quality from previous studies and reports or try to sample water which may be “outside” the influence of oil and gas development.

Determining the extent and source of water contamination is also challenging. As noted by Dr. Thyne, domestic water wells may not be ideally located to robustly determine the source of contamination. (Thyne, 2008) As pollutants disperse from their source, they may undergo chemical or physical changes, making it difficult to conclusively determine the source of pollution. Pollutants and contaminants may also interact with any media between the source and water well and result in the mobilization of naturally occurring contaminants. When such naturally occurring contaminants are detected in groundwater, it may be difficult to distinguish whether they migrated as a result of natural or anthropogenic causes or the potential link between naturally occurring contaminants and human activities may not be investigated.

Selecting the proper set of test parameters to determine the source of water contamination is also a challenge. As seen in the Garfield County example, many of the chemicals tested for in the water samples could not be used to conclusively identify the source or method of transport of contaminants because they were indicative of multiple sources and/or migration pathways.

While it is unlikely that any water contamination investigation will test for all chemicals used or released by oil and gas drilling, special care must be given to selecting proper indicator chemicals. In these and other examples, investigators often assume that the presence of biogenic gas in drinking water is not related to oil and gas activities and that thermogenic gas is related to oil and gas activities. As shown in the USGS study, this is a poor assumption. Investigators must take the next steps and determine both the source of methane in groundwater and the mechanisms by which it could migrate from its source into groundwater.

One of the most significant concerns regarding the risk of hydraulic fracturing to contaminate drinking water is that many of the chemicals used in hydraulic fracturing fluid are not known on a well by well basis. In the Bainbridge, OH case, investigators tested for three chemicals which were present in the hydraulic fracturing fluid used to frac the English No. 1 well (Ohio DNR DMRM, 2008). However, the report did not state how many chemicals in total were used in the hydraulic fracturing fluid or whether those they selected to test for represented the range of mobility and/or toxicity of all the chemicals used. In the Garfield County example, none of the studies tested the water for chemicals used in hydraulic fracturing. In their recommendations for additional work, Papadopulos and Associates stated, “The effect on groundwater due to the introduction of drilling or well completion/hydrofracturing fluids into the shallow aquifer was not investigated for this study. A study evaluating possibly local effects of drilling or hydrofracturing fluids on domestic groundwater should be considered.” (Papadopulos, 2008) Given that all studies found that deeper groundwater mixed with shallow water and that natural fractures or wellbores could provide the pathways for this contamination, testing for the presence of hydraulic fracturing chemicals and determining how induced fractures could interact with natural fractures is an extremely important piece of additional research which should be conducted.

Solutions and Lessons Learned

Detailed site characterization and planning and baseline testing prior to any oil and gas development are crucial. An integral part of understanding how wellbore construction and integrity and hydraulically induced fractures could create migration pathways to and potentially contaminate groundwater is a thorough understanding of the current geologic and hydrologic regimes. Site characterization and planning work may include but are not limited to:

- Detailed study of regional and local geologic structure including faults, fractures, stress regimes, rock mechanical properties, etc. through the use of 3D seismic surveys, outcrop analog studies, collection of core and relevant analysis, well logs including FMI/image logs, etc. As seen in Garfield County, the presence of natural faults and fractures and areas of increased fracturing around structural features may be pathways for gas, drilling fluids, hydraulic fracturing fluids or formation fluids to reach groundwater or the uncemented annuli of hydrocarbon wells and may also compromise wellbore integrity.
- Detailed pre-drill maps of the extent and chemical composition of groundwater aquifers
- Hydrologic flow and transport data collection and modeling

- Thorough identification of existing wellbores, determination of the integrity of those wellbores (i.e. casing, cement, etc.), and mitigation where necessary
- Hydrocarbon sampling and analysis to determine variations in chemical and isotopic compositions of any hydrocarbons which may be encountered both vertically in a wellbore and aerially throughout an oil or gas field

As development of an oil or gas field proceeds, these data sets must be continually updated as new information becomes available, both temporally and aerially.

Wellbore construction and integrity are paramount in protecting drinking water. Wellbores must be constructed so that any hydrocarbon or non-potable water bearing formations are isolated. As seen in Garfield County and in other examples throughout the country, shallow gas-bearing zones can be significant sources of methane in drinking water. Shallow brine or formation water or its chemical constituents may also migrate into drinking water if not isolated. Hydraulic fracturing must not occur if wellbore integrity is in question.

Wellbore maintenance is also crucial. Older wellbores which have degraded, been constructed using less protective standards, or which have been improperly abandoned must be identified and remediated. Such wellbores could provide migration pathways for contaminants to reach groundwater and hydraulically induced fractures could provide new or enhanced migration pathways for gas or fluids to reach these wellbores.

A water quality monitoring program should be developed and implemented throughout the life of oil and gas exploration and production. The use of dedicated water quality monitoring wells should be considered in order to help detect the presence of contaminants prior to their reaching domestic water wells. Placement of such wells should be based on detailed hydrologic flow models and the distribution and number of hydrocarbon wells.

Robust models and direct measurements of hydraulic fracture growth, including preferred fracture orientation, frac half-length, and frac height growth, are also crucial. Techniques such as microseismic monitoring, tiltmeters, and chemical and radioactive tracers should be employed over the life of the field, especially as development progresses into new areas.

Equally critical is robust post-frac monitoring. This includes tracking injected volumes of frac fluids as well as flowback volumes to better understand the potential for migration. In order to effectively monitor where frac fluids go and whether they or the chemicals they contain interact with groundwater, it is essential to know the exact chemical composition of all constituents involved in the drilling and completion process, including but not limited to:

- Drilling fluids/mud
- Frac fluid
- Connate water/produced water
- Geochemistry of producing formations and formations which serve as potential barriers between the producing formation and any aquifer

Cumulative impacts must also be considered. The risks to groundwater may increase as development progresses, as older wellbores are abandoned, and as drilling expands to new areas. The impacts of increasingly more wellbores and increased fracture density due to hydraulic fracturing and the potential impacts to drinking water must be examined.

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Revisiting the Major Discussion Points of the Technical Presentation Sessions

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. Any mention of trade names or commercial products does not constitute endorsement or recommendation for use.

The workshop lead and theme leads addressed the workshop participants and EPA at the conclusion of presentations for each theme and at the end of the workshop. Leads summarized the major discussion points and commented on research needs and data gaps.

Scott Anderson of Environmental Defense Fund, the workshop lead**,** concluded the well integrity discussions by providing some context on Texas oil and gas regulation. In 1919, Texas adopted well plugging and spacing rules. However, one week after the spacing rules were adopted, the first spacing exceptions were granted, and the well plugging rules were not enforced for some time, maybe decades. Mr. Anderson noted that some defensiveness on the part of operators is understandable when it comes to these issues; companies commit very large amounts of time and effort to identify and control risks, and the industry is justifiably proud of its accomplishments. However, all stakeholders recognize that things can and do go wrong. Mr. Anderson also stated his opinion that regulatory issues are relevant to the EPA study, even though Congress did not ask for a review of regulations. According to Mr. Anderson, when understanding risk, the state of the regulatory environment is just as relevant as industry's performance history and best practices.

Bob Whiteside of Texas World Operations, the Well Construction theme lead, concluded the discussions by describing how HF operations have changed in the past 40 years. Drilling now requires more equipment, communications, and personnel. Wells are now highly engineered and extensively examined.

Tim Beard of Chesapeake Energy Corporation, the Fracture Design and Stimulation theme lead, summarized the main points of each of the Theme 2 presentations. Terry Engelder's presentation described natural fractures above the Marcellus Shale and emphasized that there is no leakage without a driver of pressure differences. The datasets described by John Williams show that fresh water and gas can be in close proximity in some cases. Tim Beard's presentation described how fracturing is highly engineered and depends on many variables and that fractures tend to stay in low-stress zones and respond to barriers. David Cramer and Hal Macartney's presentations addressed the conditions that encourage horizontal fracture growth in shallow formations. Patrick Handren discussed how microseismic data can show that fractures are generally well contained in the Barnett and that increased well density leads to increased fracture complexity. Norm Warpinski described mineback and microseismic studies showing that vertical fracture propagation across layers is inefficient and therefore limited due to differing rock properties and stresses. Ahmed Abou-Sayed's presentation showed that pressure transient analysis can be a useful tool. Daniel Soeder proposed a tracer test. Scott

Cline explained the numerous reasons for low fluid return rates, none of which point to flow into ground water. Mr. Beard noted that evidence shows that the risk to ground water from HF is remote. However, wellbore integrity, construction, and maintenance practices, from drilling to abandonment and beyond, are all crucial. Mr. Beard added that it is easy to lose sight of the facts in favor of opinions and personal issues. He believes that the facts show HF itself is not necessarily the cause of any incidents, well construction should continue to be addressed in the future. Mr. Beard also thanked all of the workshop participants.

Jim Bolander of Southwestern Energy, the Well Integrity theme lead**,** summarized the main points addressed during the Theme 3 presentations and discussions. The goal of Theme 3 was to merge the previous two themes, well construction and fracture design. Mr. Bolander emphasized the importance of casing, cementing and pressure management. He believes that appropriate consideration of those three topics can prevent problems like the one in Bainbridge Township, Ohio.

Glossary of Terms

The sources of the definitions found in this glossary are noted at the end of each definition. Sources include the following:

Abbreviated Source	Full Source Name
SPE	Society of Petroleum Engineers Exploration & Production Glossary (http://www.spe.org/glossary/wiki/doku.php/)
Schlumberger	Schlumberger Oilfield Glossary (http://www.glossary.oilfield.slb.com/default.cfm)

ABBREVIATIONS

BHTP bottom hole treating pressure
BLM Bureau of Land Management
BOP blowout preventer
BTEX benzene, toluene, ethylbenzene, and xylene
CBL cement bond log
CET cement evaluation tool
COGCC Colorado Oil and Gas Conservation Commission
DMRM Ohio Department of Natural Resources, Division of Mineral Resources Management
E&A Eckstein & Associates
E&P exploration and production
ECP external casing packer
EMW equivalent mud weight
ESOGIS Empire State Oil and Gas Information System
FIT formation integrity test
GIS geographic information system
HHP hydraulic horsepower
HMX cyclotetramethylene trinitramine
HNS hexanitrosilbene
ISIP instantaneous shut-in pressure
LTC long thread and coupled casing connection
MASP maximum anticipated surface pressure
MATP maximum anticipated treating pressure
MIT multi-finger imaging tool
MTT magnetic thickness tool
NACE National Association of Corrosion Engineers
NORSOK Norsk Sokkels Konkuranseposisjon
NWIS National Water Information System
OD outer diameter
OVESC Ohio Valley Energy Systems Corporation
P&A plugging and abandonment (of a well)
PA DEP Pennsylvania Department of Environmental Protection
PNL pulsed neutron log
RDX cyclotrimethylene trinitramine
RRC Texas Railroad Commission
SAPT standard annulus pressure test
SBT segmented bond tool

SCP sustained casing pressure
SRV stimulated reservoir volume
STC short thread and coupled casing connection
TCEQ Texas Commission on Environmental Quality
Tcf trillion cubic feet
TD total depth (of a well)
TDS total dissolved solids
TDT thermal decay time
TOC top of cement
UCA ultrasonic cement analyzer
USDW underground source of drinking water
USGS United States Geological Survey
USIT UltraSonic Imager Tool
WFL water flow log
WHTP wellhead treating pressure
WOC waiting on cement

GLOSSARY

API American Petroleum Institute
back pressure a pressure caused by a restriction or fluid head that exerts an opposing pressure to flow (SPE)
casing head a term that applies to the wellhead flange that forms the transition between pipe and the flange-build tree. It may be attached by threads, welding, pressure forming or lock-ring/screw devices (SPE)
casing string a continuous string of casing, usually cemented over at least part of its length and usually extending back to surface from the set point (SPE)
control head an extension of a retrievable tool that is used to set and release the tool (SPE)
displacement volume the volume of a wellbore occupied by fluid. When the swept volume varies from the calculated displacement, part of the wellbore may not be actively swept (SPE)
equivalent mud weight The equivalent mud weight felt by the formation when circulating with a certain mud weight and holding a backpressure. A 10 lb/gal mud in a 10,000 ft well with 1000 psi backpressure would generate an equivalent mud weight of about 11.9 lb/gal. (SPE)
external casing packer a rubber bladder over a section of casing that is inflated, usually with cement, to give an annular seal in open hole sections. Frequently used with liners and set at intervals along the open hole. (SPE)
fracture gradient the gradient needed to initiate a fracture (SPE)
gamma ray log A log of the total natural radioactivity, measured in API units. The measurement can be made in both openhole and through casing. The depth of investigation is a few inches, so that the log normally measures the flushed zone. Shales and clays are responsible for most natural radioactivity, so the gamma ray log often is a good indicator of such rocks. However, other rocks are also radioactive, notably some carbonates and feldspar-rich rocks. The log is also used for correlation between wells, for depth correlation between open and cased hole, and for depth correlation between logging runs. The gamma ray log was the first nuclear well log and was introduced in the late 1930s.
hydrostatic pressure pressure exerted by a column of fluid (SPE)
Instantaneous shut-in pressure Used to isolate the formation fracturing or injection effect from the friction effects (SPE)
Intermediate Casing often a casing string or liner run to isolate a zone between the surface casing and the final production casing (SPE)
interval the pay zone exposed to the wellbore. This may or may not be the entire pay. Also referred to as completion interval. (SPE)
kick tolerance an estimate of the volume of gas influx at bottom hole condition that can be safely shut in and circulate out of the well (SPE).
mesh a measurement of particle size based on the openings per inch in a screen (SPE)

mud weight mud weight The mass per unit volume of a drilling fluid, synonymous with mud density. Weight is reported in lbm/gal (also known as ppg), kg/m3 or g/cm3 (also called specific gravity or SG), lb/ft3 or in hydrostatic gradient, lb/in2/ft (psi/ft) or pptf (psi/1000 ft). Mud weight controls hydrostatic pressure in a wellbore and prevents unwanted flow into the well. The weight of the mud also prevents collapse of casing and the openhole. Excessive mud weight can cause lost circulation by propagating, and then filling, fractures in the rock. Mud weight (density) test procedures using a mud balance have been standardized and published by the American Petroleum Institute (API). (Schlumberger)

pay zone hydrocarbon producing interval (SPE)

plastic viscosity an absolute flow property indicating the flow resistance of certain types of fluids. A measurement of shear stress. (SPE)

play a pay zone or set of pay zones with proven commercial reserves (SPE)

pressure out *see screen out*.

production casing the innermost casing string that straddles and isolates the producing interval (SPE)

PWS public water system

rathole Extra hole drilled at the bottom of the hole to leave expendable completion equipment, such as the carriers for perforating gun charges (Schlumberger)

rheology the study of the deformation and flow of matter. Real fluids include non-elastic solids, non-Newtonian fluids and viscoelastic substances. The added materials that provide viscosity range from clays to polymers to complex surfactant chemistry (SPE)

riser pipe through which liquid travels upward (SPE)

screen out an early time frac failure when the frac width is too small and the fracture proppant bridges off on the fracture. (SPE)

shoe the end of the casing, usually called a guide shoe, that helps insert the casing through the drilled hole (SPE)

slickwater a water base fluid with only a very small amount of a polymer added to give friction reduction benefit (SPE)

sour service defined in NACE MR-0175/ISO 15156 as exposure to oilfield environments that contain H2S and can cause cracking of materials by the mechanisms addressed by NACE MR-0175/ISO 15156 (SPE)

SPE Society of Petroleum Engineers

spud to begin drilling (SPE)

wireline Related to any aspect of logging that employs an electrical cable to lower tools into the borehole and to transmit data. Wireline logging is distinct from measurements-while-drilling (MWD) and mud logging (SPE)

workover repairing a well. Usually implies opening the well and running in with a tubing string. May or may not involve killing the well and may or may not involve a conventional rig. (SPE)

yield point the resistance to initial flow of a fluid or stress required to start fluid moving (SPE)

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