

Full Documentation

**Proceedings and Minutes of the
Hydraulic Fracturing Expert Panel
XTO Facilities, Fort Worth
September 26, 2007**

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Meeting Opening

The Barnett Shale Water Conservation and Management Committee Meeting that hosted the Hydraulic Fracturing Expert Panel was called to order by Tom Hayes. The meeting facilities and lunch were provided by XTO Energy; the meeting was opened with a few words of welcome from Doug Agee of XTO.

Panel Members

Tom Hayes introduced the Panel Members to the meeting attendees. Members of the Expert Panel are described in Table 1; this table was used for the introduction section of the meeting.

Table 1. Members of the Expert Panel

Name	Affiliation	Area of Expertise
Dusty Weatherly	ConocoPhillips	Petroleum Engineering - Completions
Chuck Kelly	Consultant	Field Completions Supervisor
Gary Schein	BJ Services	Hydraulic Fracturing Fluids Expertise Provider
Von Parkey	Halliburton	Hydraulic Fracturing Expertise Provider
Rusty Werline	Devon Energy	Field Completions Supervisor
Mike Murphy	Champion Technologies	Chemicals Applications for Well Completions
John Whittington	EOG Resources	Petroleum Engineering - Completions

Overview

Tom described the background, rationale and approach for conducting the Expert Panel. The goal of the panel was stated as follows: “Determine the minimum water quality requirements for reliable and effective hydraulic fracturing of the Barnett Shale for natural gas production.” The central questions to be addressed by the Panel were presented. These are shown in Table 2. Five of the questions (Foundational Questions) were addressed by the Panel before the meeting; five of the questions (Discussion Questions) were to be covered during the Expert Panel meeting. Overview slides are contained in the Slide Presentation of the Appendix.

Table 2. Critical Questions to be Addressed by the BSWCMC Hydrofracturing Expert Panel on Water Quality.

Type	Panel Questions
Foundational Questions	1. What key frac fluid properties are we trying to create with freshwater as an ingredient in the slickwater fracing process?
	2. What are the identified water impurities of concern in the Barnett Shale flowback / produced water?
	3. Which of the impurities affect the desired frac fluid properties noted in Question 1?
	4. What levels of impurities can be tolerated and continue to maintain efficient frac placement?
	5. What are additional safety considerations when pumping Barnett Shale flowback / produced water?
Discussion Questions	6. Are there incompatibility issues when fracing with mixed waters from different sources?
	7. Will the use of flowback / produced water affect the plug / perforating procedure in between frac stages?
	8. Are there frac equipment or downhole tubular reliability/function issues when comparing freshwater to flowback / produced water fracing?
	9. Are fluid dynamics such as leak-off and viscosity affected positively by flowback / produced water? Or is there a difference compared to freshwater?
	10. In your professional opinion, what is the maximum level of impurities that can be practically used to hydraulically fracture the Barnett Shale and avoid reservoir damage? <ul style="list-style-type: none"> ➤ Oil and Grease ➤ Soluble Organics ➤ Chlorides ➤ Bicarbonates/Carbonates ➤ Ca / Mg / Mn / Fe / Ba / etc. ➤ Scale Index Limits ➤ Suspended Solids ➤ Total Dissolved Solids ➤ Bacterial Counts ➤ pH / Eh Limits

Panel Response to the Foundational Questions

Clyde Findlay covered the Panel responses to the five Foundational Questions. These questions were mailed to the panel and panel members prepared their responses and submitted them prior to the meeting. These responses were then summarized to the Panel and attendees at this meeting.

Table 3. Panel Responses to the Foundational Questions.

Question	Responses from the Panel	Comment
<p>1. What key frac fluid properties are we trying to create with freshwater as an ingredient in the slickwater fracing process?</p>	<ul style="list-style-type: none"> ▪ Low viscosity; sufficient to transport proppant ▪ Consistent and clean ▪ Non-reactive ▪ Safe (non-flammatory, non-toxic) ▪ Fluid that works w/ friction reducers to achieve the designed flow rates and pressure limits ▪ No or minimal residuals ▪ Limited formation damage ▪ Minimum potential for water-side corrosion and scaling ▪ Residual frac gel damage avoided ▪ Cheap to modify fluid properties ▪ Minor environmental effects ▪ Low entrained solids content ▪ Neutral pH for max polymer hydration 	<p>Summary</p> <ul style="list-style-type: none"> ▪ Low Viscosity ▪ Non-reactive ▪ Non-Flammatory ▪ Minimal residuals ▪ Minimal potential for scale & corros ▪ Low entrained solids ▪ Circum Neutral pH
<p>2. What are the identified water impurities of concern in the Barnett Shale flowback / produced water?</p>	<ul style="list-style-type: none"> ▪ Precipitated & entrained solids (scaling tendencies) <ul style="list-style-type: none"> ➢ Ca, Mg, Ba, Sr ➢ Mineral scales (calcium carbonate & BaSO4) ➢ Iron solids (iron oxide and iron sulfide) ➢ Frac sand ➢ Dispersed clay fines, colloids & silts ▪ High dissolved solids levels (chlorides, sulfates, calcium, etc. ▪ Bacteria <ul style="list-style-type: none"> ➢ Anaerobic acid producer bacteria (APB) ➢ Anaerobic sulfate reducing bacteria (SRB) ▪ Suspended Solids ▪ Liquid & gas hydrocarbons ▪ Acid gases (CO2 & H2S) that relate to corrosion and well fluid souring ▪ Friction reducer residue 	<p>Summary of Concerns</p> <ul style="list-style-type: none"> ▪ Scale Forming Constituents ▪ High Dissolved Solids (Chlorides, Sulfates, & Calcium) ▪ Bacteria:APB & SRB ▪ Suspended Solids ▪ Hydrocarbons ▪ Acid Gases (CO2 & H2S) ▪ Friction Reducers
<p>3. Which of the impurities affect the desired frac fluid properties noted in Question 1?</p>	<ul style="list-style-type: none"> ▪ Chlorides increase demand for friction reducers and scale inhibitors ▪ Scale potential [f(Ca, Mg, Ba, SO4, CO3...)] ▪ Suspended solids (> 25 microns) ▪ Bacterial growth (SRB and APB) ▪ Crude oil effects on friction reducer ▪ Scale & corrosive materials affect 	<p>This list of impurities is important in prioritizing treatment requirements for flowback water reuse.</p> <p>All of these problematic impurities can be</p>

Question	Responses from the Panel	Comment
	downhole and surface production facilities <ul style="list-style-type: none"> ▪ Adding inhibitors affects friction reducers ▪ Hydrocarbons can be a safety issue 	controlled through water treatment and conditioning.
4. What levels of impurities can be tolerated and continue to maintain efficient frac placement?	<ul style="list-style-type: none"> ▪ Chlorides, mg/l <ul style="list-style-type: none"> ➢ < 3,000 (1 panel member) ➢ < 10,000 (3 panel members) ➢ < 35,000 (2 panel members) ➢ < 90,000 (1 panel member) ▪ Ca⁺⁺ mg/l <ul style="list-style-type: none"> ➢ < 350 ➢ < 500 ➢ < 1,000 ▪ Suspended Solids < 50 mg/l ▪ Entrained oil & soluble organics < 25 mg/l ▪ Bacteria, cells/100 ml < 100 ▪ Soluble gas removal - To non-problem levels. ▪ Low levels of Ba⁺⁺ - To non-problem levels. 	<p>More comments on the chloride levels were a part of the interactions over the Discussion Questions.</p> <p>At several points in the interactions over the Discussion Questions it was pointed out that at over 350 mg/l, calcium begins to affect friction reducer demand in the course of performing the frac job. More discussion was also given on suspended solids and bacteria.</p>
5. What are additional safety considerations when pumping Barnett Shale flowback / produced water?	<ul style="list-style-type: none"> ▪ Spillage potential (prefrac, post frac, during frac) [> 4,000 mg/l cannot be spilled] ▪ Flammability hazard where hydrocarbon condensates and gas predominate ▪ Scale forming on pipe leading to corrosion failure ▪ BaSO₄ scale ▪ H₂S content and potential health risk ▪ Equipment plugging ▪ Salt corrosion causing metal failure 	Engineering design of water handling systems needs to take these factors into consideration.

After summarizing the previously prepared written responses, Clyde invited the Panel for any additional thoughts that need to be added. One point was made by Rusty that significant corrosion risk can be presented during the flowback period by the presence of acid gases, including CO₂ and H₂S.

Gary added a historical backdrop that explains the nature of friction reducers. Friction reducers (FR) were first developed as flocculants for water treatment, so it makes sense that high suspended solids in water uses up friction reducers. Von added that most of the experience with friction reducers came from the paper industry. Over the last year and a half, we have started to obtain more and more information on the use of FRs in E&P applications. One thing that has been learned from practical use of FRs is that around 350 mg/l of calcium, you start to adversely affect most friction reducers. Some

variance to this rule occurs among different FRs. It has also been found that around 35,000 mg/l chloride, salinity starts to adversely impact friction reducer demand in the course of performing frac jobs.

Added discussion on this issue seemed to lead to some agreement that the use of saline, freshwater, distilled water or mixtures thereof did not seem to produce large differences in ultimate well performance in the post-frac years. There could be, however, significant differences in costs in terms of friction reducer demand during the frac job and the degree of control required for controlling scale, corrosion and bacteria in the post-frac years. The main tradeoff in most cases, though, seems to be the expense of friction reducer versus water availability and transport.

Discussion Questions

Following the coverage of the above responses by the expert panel, Clyde Findlay and Tom Hayes led the Panel in consideration of the Discussion Questions. A summary of the comments and discussion on the Discussion Questions is found in Table 4. More details of this discussion can be found in the Transcript of the Expert Panel which is included in the Appendix.

Table 4. Summary of Comments from the Expert Panel on the Discussion Questions.

Question	Summary of Discussion	Implications
6. Are there incompatibility issues when fracing with mixed waters from different sources?	<ul style="list-style-type: none"> ▪ Scaling tendencies may arise, even during a frac job and during the release of flowback water. Most concern over BaSO₄ and CaSO₄ precipitates. ▪ Need to watch pH resulting from the mixing of water streams. pH can affect the formation of carbonate based scale. ▪ Presence of iron resulting from water blending can cause problems. High iron concentrations can cause problems with plugging. ▪ When planning which water to blend, it is good to implement scale inhibition programs, like to Oddo-Thompson model. ▪ Mixing flowback water from various wells may result in some FR residuals being transferred. ▪ In water reuse systems, FRs may be removed to avoid treatment equipment fouling. ▪ No incompatibility is expected in the mixing of flowback water with Ellenberger water. ▪ Mixing of flowback waters from wells located in diverse places in the Barnett is not expected to present problems. 	<p>Be careful about what types of industrial waters are used for performing frac jobs.</p> <p>The effectiveness of FR's transferred from well to well may be a research issue.</p>
7. Will the use of flowback /	The consensus of the Panel was that in principle the use of recycled flowback (FB) or	No intrinsic show stoppers in the

Question	Summary of Discussion	Implications
<p>produced water affect the plug / perforating procedure in between frac stages?</p>	<p>produced water (PW) in place of 100 percent freshwater should not make a difference in the placement of the hydraulic fractures or in well production performance. The reason is that it's a pretty dirty downhole environment anyway, and that with the use of appropriate precautions, introduction of reused flowback or produced water is not likely to present problems in terms of overall well performance. Sand, friction reducers and other chemicals that are added on purpose comprise a fairly dirty environment.</p> <p>It was noted that the viscosity of saline waters of FB or PW streams that are in the range of 35,000 mg/l chlorides should have a viscosity of about 1.5 to 2 centipoise (compared to 1.0 centipoise for freshwater). The physical behavior of the saline fluids, therefore, is expected to be very similar to that of freshwater.</p>	<p>actual use of saline waters for performing frac jobs in terms of the effective placement of hydraulic fractures and in terms of resulting gas production performance.</p>
<p>8. Are there frac equipment or downhole tubular reliability function issues when comparing freshwater to flowback / produced water fracing?</p>	<p>The main equipment issues of using FB and PW for fracing include:</p> <ul style="list-style-type: none"> • Acid gas corrosion -- because chlorides in FB and PW make it worse. • Bacteria --- because they transform SO₄ to H₂S acid gas and lead to plugging. • Scale forming potential. This is high with many waters used for fracing. Scale can plug a well in as short a time as a month. <p>In terms of the effects on frac equipment that is used transitionally to complete a well, we don't see much of an effect on well performance due to water quality.</p> <p>The biggest source of mechanical wear on frac equipment and tubulars is the presence of sand.</p> <p>When using flowback water (FB) and produced waters (PW), it may be necessary to pay more attention to biocide treatment for microbial control. Also, the introduction of water with elevated sulfate would require more attention to biocide treatment to control sulfate reducing bacteria and avoid excessive H₂S generation.</p>	<p>Reuse of flowback or produced waters for the performance of frac jobs means that more preventive maintenance is needed in terms of early and regular treatment with biocides, corrosion inhibitors and scale inhibitors. These problems, however, can be controlled and do not represent factors that should prevent FB and/or PW reuse.</p>

Question	Summary of Discussion	Implications
	<p>Presence of chlorides above 35,000 mg/l accelerates acid gas (i.e. CO₂ and H₂S) corrosion which can be a problem for tubulars.</p>	
<p>9. Are fluid dynamics such as leak-off and viscosity affected positively by flowback / produced water? Or is there a difference compared to freshwater?</p>	<p>Salt water has better leakoff and viscosity properties, but only to a slight extent.</p> <p>The most immediate difference in switching from freshwater to the use of flowback or produced water for fracing is the increased dosing of friction reducers to complete the frac job. Some were of the opinion that chloride levels over 10,000 mg/l triggers the increased demand for friction reducers to place the required fracs.</p>	<p>This category of water properties is not likely to be a controlling factor in water reuse and management.</p>
<p>10. In your professional opinion, what is the maximum level of impurities that can be practically used to hydraulically fracture the Barnett Shale and avoid reservoir damage?</p>	<p>Oil and grease. No problem at levels up to 200 ppm (by unanimous agreement).</p> <p>Soluble organics. Through a show of hands, the Panel responded that soluble organics are not a problem with water pumped downhole.</p> <p>Chloride. Clyde stated the key question: How many of the Panel Members would frac with a certain concentration of chloride? 3,000 mg/l: 7 Panel members raised hands 10,000 mg/l: 7 raised hands 35,000 mg/l: 3 raised hands 60,000 mg/l: 2 raised hands 90,000 mg/l: 2 raised hands</p> <p>Calcium, Magnesium, Carbonate. These parameters can be managed collectively through the use of scale control models (e.g. Oddo-Thompson Model).</p> <p>Ba, SO₄. Simple solubility calculations are often sufficient to predict problematic levels of these constituents. However, the scale formation computer models are also useful for this.</p> <p>Iron. The panel agreed that levels of iron under 20 ppm are not a problem.</p>	<p>In general, this information will be examined further and will be useful in defining treatment guidelines and goals for FB and PW reuse systems development efforts.</p>

Question	Summary of Discussion	Implications
	<p>Soluble Calcium. Most of the Panel believes that over 350 mg/l of soluble calcium triggers greater demand for friction reducer during the frac job procedure.</p> <p>Suspended Solids. Up to 100 mg/l of TSS are not a problem. Even higher concentrations would probably have no effect on frac job quality.</p> <p>Eh. All of the Panel indicated that this parameter is not likely to be problematic in the reuse of FB or PW in frac jobs.</p> <p>pH. Biocide effectiveness is the main concern with this parameter. Most biocides work best below pH 7, though many biocides will still work between pH 7 and 8. Highly alkaline frac waters (above pH 8) should be avoided.</p> <p>Total Dissolved Solids (TSS). The Panel agreed that this parameter is covered through the guidelines on chlorides (conversion to NaCl from chloride is fairly straight forward).</p> <p>Bacteria. This parameter is usually handled indirectly through guidelines on biocide residuals.</p>	

Conclusions

The conclusive responses from the Frac Job Expert Panel are summarized in Table 5. Within the table, the responses are identified with each of the questions posed to the panel. Overall, a fairly high level of agreement was found among responses to a majority of the questions; where differences of opinion existed, common-ground compatible statements could be found and stated as shown in the table.

Table 5. Conclusive Responses from the Frac Job Expert Panel

Question	Conclusions
<p>Summary of Written Responses to <u>Foundational Questions</u> Obtained from Panel Members Prior to the Panel Discussion</p>	
<p>1. What key frac fluid properties are we trying to create with freshwater as an ingredient in the slickwater fracing process?</p>	<p>Key frac fluid properties include:</p> <ul style="list-style-type: none"> ▪ Low Viscosity ▪ Non-reactive ▪ Non-Flammatory ▪ Minimal residuals ▪ Minimal potential for scale & corrosion. ▪ Low entrained solids ▪ Around Neutral pH (pH 6.5 – 7.5)
<p>2. What are the identified water impurities of concern in the Barnett Shale flowback / produced water?</p>	<p>Impurities of concern include:</p> <ul style="list-style-type: none"> ▪ Scale Forming Constituents ▪ High Dissolved Solids (Chlorides, Sulfates, & Calcium) ▪ Bacteria: Acid Producing Bacteria (APB) & Sulfate Reducing Bacteria (SRB) ▪ Suspended Solids ▪ Hydrocarbons ▪ Acid Gases (CO₂ & H₂S) ▪ Friction Reducers
<p>3. Which of the impurities affect the desired frac fluid properties noted in Question 1?</p>	<p>The impurities that affect the desired frac fluid properties (as per Question 1) include:</p> <ul style="list-style-type: none"> ▪ Chlorides increase demand for friction reducers and scale inhibitors ▪ Scale potential [f(Ca, Mg, Ba, SO₄, CO₃...)] ▪ Suspended solids (> 25 microns) ▪ Bacterial growth (SRB and APB) ▪ Crude oil effects on friction reducer ▪ Scale & corrosive materials affect downhole and surface production facilities ▪ Adding inhibitors affects friction reducers
<p>4. What levels of impurities can be tolerated and continue to maintain efficient frac placement?</p>	<p>The levels of impurities that can be tolerated in terms of performing an efficient frac placement are as follows:</p> <ul style="list-style-type: none"> ▪ Chlorides: Panel responses ranged from 3,000 to 90,000 mg/l; however, 6 out of 7 Panel Members thought that 10,000 mg/l Cl was acceptable.

Question	Conclusions
	<ul style="list-style-type: none"> ▪ Ca⁺⁺: Panel responses ranged from 350 to 1,000 mg/l; however, all panel members agreed that a calcium level over 350 mg/l begins to increase friction reducer demand. ▪ Suspended Solids < 50 mg/l ▪ Entrained oil & soluble organics < 25 mg/l ▪ Bacteria, cells/100 ml < 100 ▪ Soluble gas removal - To non-problem levels as defined by safety requirements and corrosion specifications. ▪ Low levels of Ba⁺⁺ - To non-problem levels as defined by scale forming potential.
<p>5. What are additional safety considerations when pumping Barnett Shale flowback / produced water?</p>	<p>The main safety considerations include:</p> <ul style="list-style-type: none"> ▪ Spillage potential ▪ Moderate flammability hazard ▪ Scale forming potential ▪ Moderate H₂S content and potential health risk ▪ Equipment plugging ▪ Salt corrosion causing metal failure
<p>Responses to <u>Discussion Questions</u> Addressed During the Expert Panel Meeting</p>	
<p>6. Are there incompatibility issues when fracing with mixed waters from different sources?</p>	<p>There are no apparent incompatibility issues associated with introducing mixed waters in the Barnett Shale formation. Precautions, however include the following:</p> <ul style="list-style-type: none"> ▪ Scaling tendencies may arise, even during a frac job and during the release of flowback water. Most concern over BaSO₄ and CaSO₄ precipitates. ▪ Need to watch pH resulting from the mixing of water streams. The pH can affect the formation of carbonate based scale. ▪ Presence of iron resulting from water blending can cause problems. High iron concentrations can cause problems with plugging. ▪ When planning which water streams to blend, it is good to implement scale inhibition programs, like the Oddo-Thompson Model. ▪ Scale formation incompatibility may occur in the mixing of flowback water with Ellenburger water; however, this can be mitigated through the use of computer models for scale formation prediction (such as the Oddo-Thompson Model) and through the informed use of scale inhibitors. ▪ The mixing of flowback waters from wells located in diverse places on the Barnett is not expected to present problems. ▪ Care should be taken over what types of industrial waters are used for performing frac jobs (e.g. flu gas desulfurization impoundments, high iron industrial waters, etc.)

Question	Conclusions
7. Will the use of flowback / produced water affect the plug / perforating procedure in between frac stages?	<p>No. The consensus of the Panel was that in principle the use of recycled flowback (FB) or produced water (PW) in place of 100 percent freshwater should not make a difference in the placement of the hydraulic fractures or in well production performance. The reason is that it's a pretty dirty downhole environment anyway, and that with the use of appropriate precautions, introduction of reused flowback or produced water is not likely to present problems in terms of overall well performance. Sand, friction reducers and other chemicals that are added on purpose comprise a fairly dirty environment.</p> <p>Furthermore, there are no intrinsic show stoppers in the actual use of saline waters for performing frac jobs in terms of the effective placement of hydraulic fractures and in terms of stimulation of gas production performance.</p>
8. Are there frac equipment or downhole tubular reliability function issues when comparing freshwater to flowback / produced water fracing?	<p>No. In terms of the effects on frac equipment that is used transitionally to complete a well, we don't see much of an effect on well performance due to water quality.</p>
9. Are fluid dynamics such as leak-off and viscosity affected positively by flowback / produced water? Or is there a difference compared to freshwater?	<p>Minimally, yes. Salt water has better leakoff and viscosity properties, but only to a slight extent. This category of water properties is not likely to be a controlling factor in water reuse and management.</p>
10. In your professional opinion, what is the maximum level of impurities that can be practically used to hydraulically fracture the Barnett Shale and avoid reservoir damage?	<p>Oil and grease. No problem at levels up to 200 ppm (by unanimous agreement).</p> <p>Soluble organics. Through a show of hands, the Panel responded that soluble organics are not a problem with water pumped downhole.</p> <p>Chloride. In the final deliberation, seven out of seven panel members thought that 10,000 mg/l chlorides would be acceptable for use downhole to achieve effective hydraulic fractures.</p> <p>Calcium, Magnesium, Carbonate. These parameters can be managed collectively through the use of scale control models (e.g. Oddo-Thompson Model).</p> <p>Ba, SO₄. Simple solubility calculations are often sufficient to predict problematic levels of these constituents. However, the scale formation computer models are also useful for this.</p>

Question	Conclusions
	<p>Iron. The panel agreed that levels of iron under 20 ppm are not a problem.</p> <p>Soluble Calcium. Most of the Panel believes that over 350 mg/l of soluble calcium triggers greater demand for friction reducer during the frac job procedure.</p> <p>Suspended Solids. Up to 100 mg/l of TSS are not a problem. Even higher concentrations would probably have no effect on frac job quality.</p> <p>Eh. All of the Panel indicated that this parameter is not likely to be problematic in the reuse of FB or PW in frac jobs.</p> <p>pH. Biocide effectiveness is the main concern with this parameter. Most biocides work best below pH 7, though many biocides will still work between pH 7 and 8. Highly alkaline frac waters (above pH 8) should be avoided.</p> <p>Total Dissolved Solids (TDS). The Panel agreed that this parameter is covered through the guidelines on chlorides (conversion to NaCl from chloride is fairly straight forward).</p> <p>Bacteria. This parameter is usually handled indirectly through guidelines on biocide residuals and the use of field-related test cultures where applicable.</p>

Close of Expert Panel Meeting

Tom Hayes thanked the Panel and the Attendees for making the Expert Panel Meeting a success.

A special thanks was extended to XTO Energy and to XTO staff (Kathy Dolff and Doug Agee) for providing the meeting facilities and food in support of this event.

In the coming weeks, the transcript of the proceedings will be made available for the Panel Members to review. The output for this meeting will be a summary of the findings of the Panel.

The next meeting is on November 7 at Range Resources.

Appendix

Proximal Transcript of the Panel Discussion

Proximal Transcript of Panel

Following the summary description of the Panel responses to the Foundational Questions by Clyde Findlay, the following dialogue was initiated.

Foundational Question Discussion

- Clyde Does the panel have anything else to add to the summary of the Panel responses to the Foundational Questions? By the way, where does the corrosion risk mainly come from in association with the fracing process?
- Rusty It mainly comes from the acid gas buildup during the flowback period. Acid gases mainly include CO₂ and H₂S.
- Gary Another thing to add to our comments is that a “friction reducer” is a polymer ... like a gel. Friction reducers (FR) were first developed as flocculants for water treatment. So it makes a lot of sense that high suspended solids in water uses up friction reducers. Water of a high suspended solids can be pumped down hole, but if this is done, you will have to add friction reducer at a higher dosage.
- Tom What is the trigger in suspended solids that makes friction reducers go up by more than 25%?
- Von Most of the experience with friction reducers comes from the paper industry. Over the last one and a half years, we have started to obtain more and more information on the use of friction reducers in E&P applications. At around 350 mg/l of calcium, you start to impact your friction reducer demand significantly. Some variance to this rule occurs among the different friction reducers. Water with around 35,000 mg/l chloride or 6% NaCl or 7% KCl starts to impact friction reducer demand in frac jobs. This suggests that salt concentrations cause the friction reducer to denature or to change in a way that makes it less effective. This might point to the need to develop friction reducers that can tolerate high saline waters.
- Clyde You know that drilling fluids of greater than 100,000 chloride are used for well construction and that certain polymers are used to promote flocculation during above ground treatment. Such polymers may be useful as friction reducers for high saline frac waters. Just something to think about.
- Rusty, have you seen any difference in wells frac'd with Fountain Quail water and normal fresh water?
- Rusty We actually blend waters for many frac jobs. We used 90% distilled water for fracs, but we really didn't see a difference in production. We also used 50,000 to 60,000 mg/l chloride water --- we used more friction reducers, but we really didn't see much difference in well performance. What we did see was that the use of high Cl⁻ water led to more bacteria problems due to all the other residues (sic) in the fluid. Scaling due to BaSO₄ deposits on tubulars are a challenge no matter what kind of water you use. However, as far as production performance goes, there is hardly a 2-3% difference between wells frac'd with fresh water versus saline waters.
- Clyde From what I'm hearing, in using freshwater, distilled water or saline waters, you don't see a huge difference in well performance results. Big difference in cost

Foundational Question Discussion

perhaps in terms of bacteria, scale and corrosion control and friction reducer demand. What we also have is a friction reducer versus water availability tradeoff.

- Rusty A lot of our scale appears 4-5 years down the road, so much of the scale formation is not related to flowback water.
- Gary Talking about solids. The amount of friction reducer (FR) required goes up with the chlorides in the water pumped downhole. But you have to balance friction reducer cost with costs associated with water availability and disposal. Once we get solids less than 25 μ , it makes little difference to make the water cleaner. We have seen wells frac'd with water up to 90,000 mg/l chloride (9-lb brine) with friction reducers. It takes another half a gallon, but it can be done. You just have to pay the price. The 2 μ size of particle is equivalent to bacteria size; very small --- microscopic. We should also note that there are not a lot of mineral constituents in flowback water of high solubility in the Barnett.

Discussion Questions

- Tom Now let's turn to the Discussion questions. The first discussion question is [Question 6](#):

[Are there incompatibility issues when frac'ing with mixed waters from different sources?](#)

Any nightmare stories? Or is this pretty much a straight forward, non-problematic step.

- Gary Scaling tendencies may arise in mixing waters. During a frac job, you could look at the pressure chart and you can often tell when one tank of fluid ended and when another tank was introduced just from the friction reducer demand during the frac job.
- Mike I would reiterate the same thing. During drought, we had to use river water, pipeline water, make water, and there were problems of scaling and other issues. Scaling was the big issue. Most of the wells use freshwater. But most freshwater sources have sulfates. This water does not cause problems when being pumped into the formation. However, once the water gets into the formation, it equilibrates with the minerals in the formation. The presence of sulfate in the water plus the calcium, barium and strontium in the mineral rock can lead to the formation of precipitates, mainly BaSO₄ and CaSO₄. Scale inhibitors are used to prevent scale formation in equipment during flowback.
- Tom Maybe there are a lists of do's and don't's as to where one should obtain water for mixing with other streams for frac'ing. For instance, one thing to stay away from is FGD sludge decanted water. Don't go to your local power plant to get your frac water. Such water, when used for frac'ing, could lead to BaSO₄ and CaSO₄ scale being formed on equipment. If you mix FGD water with high carbonate groundwater, you will get significant precipitation of CaCO₃.
- Rusty You also need to watch pH.

Discussion Questions

- Tom You may also need to be wary of industrial waters of lower pH and high multivalent cation concentrations. Once this water is used for a frac job and is in the formation, the pH of the water can rise and precipitates of carbonates and sulfates can form, thus presenting a scaling problem. Therefore, more scale inhibitors would be needed to prevent scale from forming. So one principle we can possibly state is:
"Be very careful what kind of industrial waters you go after in seeking frac water."
- Gary Another factor of impurities we see in mixing water streams is represented by the presence of iron. High iron concentrations can cause some problems.
- Von When planning which water to blend, it is good to implement scale inhibition programs. You have to look at water sources, do the chemical analyses, and look at the levels of SO₄ and calcium to estimate the risk; the scale models (computer programs) can be used to predict whether scale formation will occur with the mixing of certain water streams. Before a frac job, you can calculate the concentrations of Ca and SO₄ that would result from blending certain water streams and then plug the concentration information into the scale model to predict whether problems will occur. An example of a scale model is the Oddo-Thompson model.
- John One thing that we came across when we are pumping flowback water from one well directly into another well is that we are getting friction reducer back out. Apparently, some of the friction reducer (FR) chemicals are transferred from one well to another. The question is whether this friction reducer is still effective. A research project is under way to answer this question. We are currently analyzing results. Real time testing, pressure results, scaling, etc., are included. We are getting a higher pressure response with the friction reducer, and we are adding more FR. We are early in our testing, so we don't even know how much FR we will need to add for this first trial well. Higher pressures may be needed.
- Attendee Have you done a molecular analysis to see what you are getting back as a polymer?
- John We are getting that information, but it's too early to say what the results are. The question of FR effectiveness from well to well has presented interesting problems.
- Rusty In the Fountain Quail Project, we also get FR back with flowback water. We remove FR from influent with a filter press; this is removed because FR fouls heat exchangers. We get a large rolloff box of FR (separated from water) every week.
- Jay Any issues with fluids used from a wastewater treatment plant?
- Mike Just to name a few: pH, bacteria, salts, etc. But you could control these factors at a certain cost. The high pH indicates the presence of amines generated in the treatment system. The high pH can lead to higher scale potential.
- Tom The wet well of a municipal wastewater treatment plant is usually not above a pH of 8, right?
- Mike Right.
- Clyde Are there any known incompatibilities between Ellenberger water and flowback

Discussion Questions

- water steams from various areas of the Barnett Shale?
- Mike I'm not aware of any examples of this. There are not any no-no's that are obvious.
- Rusty There are water streams that have low sulfate and I know it will have good low-scale characteristics.
- Gary When you get into known Ellenberger water, you will get into elevated SO₄ issues that present a potential problem.
- David Early testing of the Ellenberger in Palo Pinto County before the '70's shows that 60,000 mg/l TDS water exists in certain areas ---- even though 130,000 mg/l TDS water was expected.
- Gary Same thing happened in Erath County. One other point: Scale also occurs with changes in temperature and pressure.
- Jeff Any problem with other chemicals (surfactants, scale inhibitors, bactericides) presenting incompatibilities in mixing streams?
- Mike Not aware of any.

BREAK

Discussion Questions

- Clyde Now let's look at [Question 7](#):
- [Will the use of flowback / produced water affect the plug / perforating procedure in between frac stages?](#)
- {Clyde describes the plug and perforation procedures that many companies use}*
- Question 7 may not be a bad question to ask in terms of interference with our plug and perforation (P&P) procedures.
- Chuck It's a pretty dirty environment most of the time anyway. The water sometimes contains sand and larger particles. We add a little FR chemical as well. I don't see that there is much effect on P&P procedures since it is a fairly dirty downhole environment anyway. The factor that will give you the most problem is sand --- and we add that on purpose.
- Clyde In general, is the viscosity of salt water significantly higher than freshwater at the ranges of salts encountered in the flowback (FB) and produced waters (PW)? If freshwater is one centipoise, then at 35,000 mg/l chlorides, what would be the viscosity?
- Mike I think about 1.5 to 2 centipoise. There isn't that much difference in viscosity and flow behavior.
- Rusty There isn't much difference in fluid behavior --- its within the margin of error of equipment performance during the frac job.
- Tom Let's now address [Question 8](#):

Discussion Questions

Are there frac equipment or downhole tubular reliability/function issues when comparing freshwater to flowback / produced water fracturing?

Dusty I don't know of any frac equipment problems that you would have due to water quality. After the water is placed downhole, there may be scale issues. As far as getting the water pumped downhole, I don't see much effects due to water quality that slow your frac jobs down.

Tom So what we are saying is that as far as frac equipment that is transitionally used to complete a well, we don't see much effect on performance due to water quality.

Dusty Right.

Tom We don't think there is going to be any wear or corrosion issues or accumulation of residue issues on this class of equipment?

Dusty I think the biggest source of wear on tubulars and frac equipment will be due to sand.

Tom And since sand is added to the frac water on purpose, the frac equipment is already designed to account for the presence of sand, right?

Dusty Yes.

Gary The equipment is designed to handle produced water, but for fracs, we may mix waters to achieve certain operational characteristics. Certain amounts of flowback waters are mixed with fresh water to achieve a certain density. In this case, we would need to monitor volumes of each type of fluid used in the mixture which presents monitoring issues.

Clyde Where are they doing this type of mixing?

Gary Travis Peak.

Clyde Let's open Question 8 to impacts that may occur on the production of gas. During the frac, we don't seem to have many issues. But as we produce the water back, are there tubular impact issues?

Tom An added consideration is whether the quality of water I use for a frac has a long term effect on the PW (beyond the 3 months it takes to get the volumes of water I placed back out of the hole) and thereby affect the performance quality of the well.

An example: Using a high SO₄ water to frac a well. Will bacterial films convert SO₄ to H₂S and cause corrosion problems that linger for years?

Mike Depends on the water quality. If you introduce suspended solids or residue, you may have problems with plugging.

Tom The introduction of bacteria with the suspended solids would have possible long-term effects on well performance. This is something that does linger.

Rusty I know when we at Devon (and Mitchell was a part of the effort) started to use more FB and PW in our fracturing; then is when we needed more control of bacteria. Bacteria in this situation was more of a concern. Rick Wilson knows about this experience. At that time, the bacteria were more of a concern in terms of corrosion than was the scaling issue. Rick worked with us on this issue and he knows more about this experience. Looking back, our tubular corrosion problems seemed to occur frequently with these wells. When we use FB and PW in fracs, we now follow up with a bactericide program. Those wells required more chemical for corrosion and bacteria control.

Discussion Questions

Rick A big part of the corrosion problem was due to the CO₂. We didn't recognize CO₂ early on in the life of the well. Since then, we found that applying scale and corrosion inhibitors on "Day One" and forward was very beneficial. We did this at Range Resources as well. We also found that where there are pockets of bacteria problems, we had "hot spots" of H₂S problems that have to be treated with biocides to get H₂S down to a level to meet pipeline specs. Other developers that install wells in the Barnett but don't use inhibitor chemicals in early fracs are seeing problems later in the life of the well. One well was completely plugged up in 3 months. Some operators that did not use biocides and scale inhibitor early in well development paid dearly for that in problems that arose down the road.

There is a study that found that there are 9 different kinds of scale that can be formed on equipment. Examples include BaSO₄, CaCO₃, SrSO₄, CaSO₄, etc.

In our frac tanks, we are finding deposition of iron sulfide from frac waters. In some tanks we found 300 ppm of H₂S in the headspace gas of the tank. Then you have to start posting danger signs for H₂S.

Mike I've only seen one or two cases where CaSO₄ has been of any consequence.

Tom To summarize what I am hearing, the main issues are the acid gas corrosion factors, and the bacteria and chlorides that make it worse.

Rusty Chlorides accelerate the CO₂ corrosion. Wells where we are fracing with 35,000-60,000 mg/l chloride seem to show greater problems with corrosion. Not a problem that can't be handled with corrosion inhibitors. When we applied corrosion inhibitors, the corrosion problem decreased significantly. When scaling occurs, it shows up within 2-3 months within the life of the wells. Going 5-6 years ahead of this initial period, you may never see scale again.

Tom So reuse of flowback waters blended with other water streams is not necessarily a show stopper, but you may want to be more aggressive about using bactericides, scale inhibitors and corrosion inhibitors when using such water streams.

Clyde Is there a way of checking for levels of bacteria in water before pumping the water downhole ... so we can tailor the biocide levels to the need?

Mike There are two or three ways to check for biocide effect. Probably need to check biocide residual levels and then use a rapid check for bacteria in the field.

Rusty There are field methods to estimate biomass levels which might indicate bacteria levels.

Rick The test tells you how much biomass is in there, but it picks up live and dead bacterial cells. There is no good way to detect live bacteria. The current test also measures algae which has nothing to do with bacteria.

Rusty Our approach is to use an excess of biocides to ensure bacterial control. We are probably using more biocide than we need, but it is worth it if we can ensure control of the bacteria. We take the conservative approach.

I should mention that farm pond water is sometimes tough to use biocides on effectively. There is organic matter and other solids that seem to shield bacteria from biocide. Suspended solids and water quality are factors in the

Discussion Questions

- Donnie protection of bacteria.
Don't use that pond.
- Tom So in addressing Question 8, the main equipment issues of using FB and PW for fracing include:
- Acid gas corrosion -- because chlorides in FB and PW make it worse.
 - Bacteria --- because they transform SO₄ to H₂S acid gas and lead to plugging.
 - Scale forming potential. This is high with many waters used for fracing. Scale can plug a well in as short a time as a month.

Because of the above, more aggressive control of bacteria, scale and corrosion is needed when using reused water or alternate sources of water that have higher suspended solids content. We say, "Don't use that pond." But many times, that's all you have ---- especially on the Western half of the Barnett where groundwater tables pinch out.

- Brian Is it possible to do a scale inhibitor squeeze to give long term scale inhibitor life in the operation of a well?
- Mike Barnett Shale is impermeable, so a squeeze would not be possible. We usually continuously treat on the back side of the well for scale control. In general, with most Barnett wells, we see a near-term scale form due to CaCO₃ and longer term scale form based on BaSO₄.
- Clyde Let's now consider [Question 9](#):

[Are fluid dynamics such as leak-off and viscosity affected positively by flowback / produced water? Or is there a difference compared to freshwater?](#)

Dusty, I know that ConocoPhillips did some work in FR demand versus chlorides present in frac water and there was a threshold where FR became less effective. Can you address that?

- Dusty What we found was that using waters over 10,000 mg/l chloride caused us to loose the effectiveness of our FR.
- Clyde Does the salt water have better leakoff and viscosity properties? From our comments, I gather the answer is "slightly", but not enough to have someone switch over to it based on those small advantages.
- Tom John, based on EOG's experience, what do you think about this question?
- John I know that the higher chloride waters increase demand for FR's. We haven't studied this area to a great extent. In theory, you wouldn't think these would be a big effect, but we haven't studied the question.
- Tom Now let's address the last question. [Question 10](#).

[In your professional opinion, what is the maximum level of impurities that can be practically used to hydraulically fracture the Barnett Shale and avoid](#)

Discussion Questions

reservoir damage?

Let's start with consideration of **Oil and Grease (O&G)**. What is the envelope of values we can tolerate? What is the limit of O&G of FB or PW that we want to put downhole?

- Dusty
Tom I don't have much of an opinion on this.
I notice that on the answers to the Foundational Questions, someone wrote that we would want to stay less than 25 mg/l of O&G. That's a little low for a criterion for pumping water downhole, isn't it? Especially since most PWs in the oil and gas industry contains 60-200 ppm of O&G. Any thoughts on this?
- Dusty
Tom The 25 mg/l number is actually a discharge limit for release to surface waters. But in terms of well performance versus what we allow in water pumped downhole, is O&G problematic if we are talking about waters of 200 ppm or less of O&G? Everyone on the Panel is shaking their head "NO".
- Tom **Soluble Organics.** Apart for the growth of bacteria, are soluble organics a problem for water pumped downhole?
- Panel
(Collective Response) *Through a show of hands, the Panel responded that soluble organics are not a problem with water pumped downhole.*
- Tom **Chlorides.** With chloride levels, we had quite a range of responses. Given that we are prepared to engineer systems to handle and store high salinity waters at a reasonable cost, what can we tolerate in terms of chloride concentrations for waters pumped downhole?
- Clyde Why don't we poll the Panel on the chloride issue. What level of chloride would be acceptable to place the frac, while minimizing reservoir damage and negative impact to well production performance?
- Von I should point out that the effect of chloride on FR demand during fracturing really depends on what geographical area you are in within the Barnett. If you are in the mountain core area where FR is not that critical and where you only need to pump 30-40 bbl/min to achieve a frac, you can even use Ellenberger water. Of course you have to deal with the corrosion and scale problems that are associated with salt water. If you're on the side of the Barnett where you are having to pump 80-90 bbl/min for a frac job, it will make a difference.
- Gary What Von is saying is exactly right. We are also working on FR's for brine and fluids so that these waters can be reused. Of course, you will have a tradeoff of higher FR doses to allow you to reduce the cost of water hauling and disposal. However, in areas of the Barnett where you are using almost no FR, what difference does it make? You just have to keep in mind that as you reuse flowback water, the water will pick up even more salts than it previously contained. This not only applies to chlorides and sodium, but also to other salt components such as Mg and Ca. This may eventually create other issues.
- David In the early days, water was allowed to flow back out soon after the frac. When this was none, some of the early flowback water was less than 10,000 mg/l TDS and was recovered for other fracs and the rest of the water increased in salt content to 70,000 mg/l TDS. A number of frac jobs are allowing the water to be held in the formation for days or weeks before

Discussion Questions

releasing it. When that water remains in the reservoir, does it all become 50,000 TDS, or does it still come out of the hole with TDS increasing from 10,000 to 70,000 over a period of time. Does the water quickly equalize in its concentration when residing downhole?

Rusty We routinely monitor chlorides so we know what we can send to the Fountain Quail facility to process for reuse. We have shut in wells for two weeks because we've done off-set fracs and within 3 hrs of being released, we see chlorides as high as 25,000 to 30,000 mg/l. It jumps up very quickly unless you flow it back immediately. It's different from county to county, though. In Johnson County, we had a well shut in for two weeks and the flowback chlorides were high within 3 hours of flowback release, in the range of 25,000 to 30,000 mg/l. In Johnson County wells, flowback water chlorides increased quickly upon flowback water release; we could only recover 10% for reuse. In Denton County wells, flowback water chlorides increased more slowly; in these wells were able to send 30% of the water to Fountain Quail for reuse.

Clyde Specifically, we need to come up with a range of values for parameters on water recycled for downhole uses.

How many of the Panel Members would frac with a water containing 3,000 mg/l chloride?

Panel 7 of the 7 Panel Members raised hands.

(Collective Response)

Clyde How many for 10,000 mg/l chloride?

Panel 7 raised hands.

(Collective Response)

Clyde How many for 35,000 mg/l chloride?

Panel 3 raised hands.

(Collective Response)

Clyde How many for 60,000 mg/l chloride?

Panel 2 raised hands.

(Collective Response)

Clyde How many for 90,000 mg/l chloride?

Panel 2 raised hands.

(Collective Response)

Rusty I would be comfortable with 90,000 mg/l chloride if I could remove all of the other problematic residues that cause the other problems, if I had a way to store the water in an environmentally-acceptable and low-cost manner and if I had a FR that was low cost. And they are getting there with the new generation of FRs. If I could run with 90,000 mg/l chloride and only use a half gallon of FR, I would do it. But under the current state of technology and FR performance, I would go as high as 35,000 mg/l chloride.

Tom Sounds to me that development on the right FR's that would operate at high chloride levels but be cost effective would be quite beneficial.

Discussion Questions

Carbonates, Ca, and Mg. I think we usually handle these parameters through the use of a computer model for predicting scale. That is, we estimate the anionic and cationic concentrations in our water streams and enter the data into the model (such as the Oddo-Thompson model) to determine if we are at risk for scale formation, right? Computer models can be used as good predictors of what goes on in the field, right?

Mike We often use simple solubility calculations based on Ksp constants for BaSO₄ and CaSO₄ because pH doesn't affect these calculations. This hasn't changed. Other more complex calculations where pH does affect predictions of precipitation, the models – such as the one from GRI Environmental Research --- are good predictors of what happens.

Tom So model results are what is important. Not specific criteria for the concentration of carbonate or calcium or magnesium taken separately. Rather, one needs to consider the concentrations of all of these constituents taken together in equilibria calculations or in a model to determine the actual risk of scale formation. Does the Panel agree?

Panel
(Collective Response) *By show of head noddings, all of the members signaled agreement.*

Tom Now let's talk about **Iron**. From listening to the Panel discussions earlier this morning, I gather that with iron we are mainly concerned about iron sulfide. Iron in groundwater is usually considered high at or above 10 ppm. Would we be concerned with that level of iron being pumped down hole in frac water? In terms of 10 mg/l soluble iron? Is that a problem?

Panel
(Collective Response) *By a verbal poll of Panel Members, all of the Panel indicated an answer of "NO".*

Tom How about 50 mg/l?

Panel
(Collective Response) *Panel members indicated uncertainty over 50 mg/l.*

Tom How about 20 mg/l.

Panel
(Collective Response) *By consensus, the Panel indicated that 20 ppm is not a problem if the iron stays soluble downhole.*

Brian How about Ca levels with regard to the potential of FR demand?

Billy About 350 ppm is the level we try to avoid in terms of exerting FR demand.

Gary As a rule of thumb, the ration of Ca to chlorides is usually 20% in flowback.

Clyde It certainly sounds like Ca and chlorides are tied together. At a certain level, we reach a concentration of Ca that makes precipitates and causes an FR demand.

Discussion Questions

- Tom At 35,000, the chloride becomes uncomfortably high. What would be the corresponding level of Ca that would be uncomfortably high? Would that be 4,500 mg/l?
- Panel *(Collective Response)* *By consensus, the Panel indicated that the level of concern is closer to 500 mg/l.*
- Tom OK. How about **Suspended Solids (SS)**. Someone said that you have to be careful about particle sizes over 25 μ . Who on the Panel said that?
- Gary I included that because particles of that size place a demand on FR. That's what we've seen.
- Tom What concentration of > 25 μ particles are a problem with pumping fluids downhole? Somebody pointed out that we introduce sand downhole as > 25 μ particles. So this is a purposeful introduction of particles. What is actually of concern with suspended solids and what concentrations should we stay under? Wastewater treatment systems across the U.S. generally set 30 mg/l as an effluent discharge compliance goal. And you are already using pond and river water that contains over 100 mg/l of SS.
- Rusty These concentrations are not a problem. In general, waters with even higher SS can be pumped downhole. Where we will notice some difference with the high SS is in the area of FR demand. The water can even be cloudy or turbid and we would still pump the water downhole.
- Tom The next parameter is **Eh**. This parameter is also referred to as the oxidation-reduction potential or redox. The current status is that we are generally dealing with what we have in Eh and we are not monitoring or controlling for this parameter. Right?
- Panel *(Collective Response)* *Panel members nodded their heads indicating an answer of yes.*
- Tom Any other thoughts on Eh?
- Panel *(Collective Response)* *Consensus of the Panel indicated that this is not a problem.*
- Tom **pH**. Let's now consider the parameter of pH.
- Von In terms of biocide performance, you may want to maintain a pH of less than 7 but certainly not above 8. Above pH 8, biocides lose their effect.
- Mike I think between pH 6-8, you are alright with biocides. I agree that above 8 you will lose effectiveness.
- Tom Is there an example of a biocide that is used?
- Mike Gluteraldehyde and THPS.
- Tom So if you are seeking water that turns out to have a pH above 8, you may want to make an adjustment in pH. Right? There may not be a low pH limit, right? If I pump a water with pH of 6 downhole, what pH will the water assume?
- Billy The pH of the formation. You won't be able to overcome the pH of the formation for water at equilibrium downhole.
- Clyde The low pH will affect FR effectiveness and the low pH will probably not assume the formation pH during the short term of the frac.

Discussion Questions

Tom So we should still be mindful of the lower limit of pH for frac water which is around pH 6.

The **Total Dissolved Solids (TDS)** parameter. The TDS parameter might be overlapping with our discussion on chlorides. In most cases, we can calculate or estimate the TSS from the level of chlorides in the water. So we have already addressed this parameter, right?

Panel *Panel members all nodded their answer in the affirmative.*
(Collective Response)

Tom Is there a parameter that is not up on the slides that we need to consider?

Panel Several of the Panel answered: **Bacteria**.
(Collective Response)

Tom What level of bacteria do we want to stay under?

Mike I think what is usually done is we maintain a biocide level that will give an efficient kill of bacteria. Biocides usually work best at a pH range between 6 and 7.

Brian We try to maintain a residual effect that continues to kill bacteria to very low levels over a 5-6 month period

Tom Are we fairly confident that if we maintain a certain residual level of biocides, we can prevent undesirable subsurface transformations from occurring?

Brian Yes.

Tom Are there any other parameters we should consider?

Are there any more questions from the Attendees of this meeting for the Hydraulic Frac Job Expert Panel?

Attendee Are there any problems mixing fluids between Barnett areas; that is water from wells in one county being introduced into wells in another county?

Rusty I've mixed Barnett waters from different areas and have mixed PW with FB waters and there doesn't seem to be a problem. I've even used Ellenberger water with FB water to do frac jobs without problems.

Dusty The only problem with Ellenberger water is you may get sulfates that you don't want.

Tom Any other comments?

David This is an item of interest to the BSWCMC members. Yesterday I was in New Orleans attending the Interstate Oil & Gas Compact Commission (IOGCC) and learned that an IOGCC Stewardship award was given to the Fort Worth Chamber of Commerce for the Barnett Expo Event that was held in the Spring of 2007. I mention this because BSWCMC member companies participated in the event and the BSWCMC had an exhibit at the Expo as well. The Barnett Expo educational program was recognized by the IOGCC.

**Slides Shown at the Frac Job Expert Panel Meeting
September 26, 2007**

Hydraulic Fracturing Expert Panel on Water Management Issues

**Barnett Shale Water
Conservation and Management Committee**

September 26, 2007

Sign In and...

... a Word from Our XTO Host

Simplified Agenda

- **Introduction of Panel Members**
- **Overview and List of Questions Posed to the Panel**
- **Panel Response to the Foundational Questions – Clyde Findlay**
- **Break**
- **Panel Deliberation of Discussion Questions**
- **Questions from Attendees and Closing Remarks**
- **Lunch**
- **Wrap-up – Tom Hayes**
- **Adjourn at around 1:00 pm**

Introduction of Panel Members

The Expert Panel

Name	Affiliation	Expertise
Dusty Weatherly	ConocoPhillips	Petroleum Eng
Chuck Kelly	Consultant	Completions Supervisor
Gary Schein	BJ Services	Frac Fluids Expertise Provider
Von Parkey	Halliburton	Hydro Fracturing Expertise Provider
Rusty Werline	Devon Energy	Field Completions Supervisor
Mike Murphy	Champ-Tech	Chemicals Apps for Well Completions
John Whittington	EOG Resources	Petroleum Engrg Completions

Overview

Previous Findings of the BSWCMC

- **BSWCMC Water Use Study reveals that 89% of the NG industry water use is associated with frac jobs.**
- **Economics of treatment is a function of the quality of water required for reuse**
- **Need: Specifications on the minimum quality of water that can be used for frac jobs without compromising well performance**
- **Approach: Frac Job Expert Panel**

Goal

Determine the minimum water quality requirements for reliable and effective hydraulic fracturing of the Barnett Shale for natural gas production

Foundational Questions

- 1. What key frac fluid properties are we trying to create with freshwater as an ingredient in the slickwater fracing process?**
- 2. What are the identified water impurities of concern in the Barnett Shale flowback / produced water?**
- 3. Which of the impurities affect the desired frac fluid properties noted in Question 1?**
- 4. What levels of impurities can be tolerated and continue to maintain efficient frac placement?**
- 5. What are additional safety considerations when pumping Barnett Shale flowback / produced water?**

Discussion Questions

- 6. Are there incompatibility issues when fracing with mixed waters from different sources?**
- 7. Will the use of flowback / produced water affect the plug / perforating procedure in between frac stages?**
- 8. Are there frac equipment or downhole tubular reliability/function issues when comparing freshwater to flowback / produced water fracing?**
- 9. Are fluid dynamics such as leak-off and viscosity affected positively by flowback / produced water? Or is there a difference compared to freshwater?**

Discussion Questions

10. In your professional opinion, what is the maximum level of impurities that can be practically used to hydraulically fracture the Barnett Shale and avoid reservoir damage?

**Oil & Grease
Soluble Organics
Chlorides
Bicarbonates /
Carbonates
Ca / Mg / Mn /
Fe / Ba / etc.**

**Scale Index Limits
Suspended Solids
Total Dissolved Solids
Bacterial Counts
pH Limits
Eh (Redox) Limits**

Summary of Panel Responses to Foundational Questions

1

What key frac fluid properties are we trying to create with freshwater as an ingredient in the slickwater fracturing process?

- **Low viscosity; sufficient to transport proppant**
- **Consistent and clean**
- **Non-reactive**
- **Safe (non-flammable, non-toxic)**
- **Fluid that works w/ friction reducers to achieve the designed flow rates and pressure limits**
- **No or minimal residuals**

1

(Cont'd)

What key frac fluid properties are we trying to create with freshwater as an ingredient in the slickwater fracturing process?

- Limited formation damage
- Minimum potential for water-side corrosion and scaling
- Residual frac gel damage avoided
- Cheap to modify fluid properties
- Minor environmental effects
- Low entrained solids content
- Neutral pH for max polymer hydration

2

What are the identified water impurities of concern in the Barnett Shale flowback / produced water?

- **Precipitated & entrained solids (scaling tendencies)**
 - **Ca, Mg, Ba, Sr**
 - **Mineral scales (calcium carbonate & BaSO₄)**
 - **Iron solids (iron oxide and iron sulfide)**
 - **Frac sand**
 - **Dispersed clay fines, colloids & silts**
- **High dissolved solids levels (chlorides, sulfates, calcium, etc.)**

What are the identified water impurities of concern in the Barnett Shale flowback / produced water?

- **Bacteria**
 - Anaerobic acid producer bacteria (APB)
 - Anaerobic sulfate reducing bacteria (SRB)
- **Suspended Solids**
- **Liquid & gas hydrocarbons**
- **Acid gases (CO₂ & H₂S) that relate to corrosion and well fluid souring**
- **Friction reducer residue**

3

Which of the impurities affect the desired frac fluid properties noted in Question 1?

- Chlorides increase demand for friction reducers and scale inhibitors
- Scale potential [f(Ca, Mg, Ba, SO₄, CO₃...)]
- Suspended solids (> 25 microns)
- Bacterial growth (SRB and APB)
- Crude oil effects on friction reducer
- Scale & corrosive materials affect downhole and surface production facilities
- Adding inhibitors affects friction reducers
- Hydrocarbons can be a safety issue

4

What levels of impurities can be tolerated and continue to maintain efficient frac placement?

Panel Members

- Chlorides, mg/l **< 10,000 (3)** **< 3,000 (1)** **< 35,000 (2)** **< 90,000 (1)**
- Ca⁺⁺ , mg/l **< 1,000** **< 500** **< 350**
- Suspended Solids, mg/l **< 50**
- Entrained oil & soluble organics mg/l **< 25**
- Bacteria, cells/100 ml **< 100**
- Soluble gas removal
- Low levels of Ba⁺⁺ **To Non-problem Levels**

5

What are additional safety considerations when pumping Barnett Shale flowback / produced water?

- **Spillage potential** (prefrac, post frac, during frac) [$> 4,000$ mg/l cannot be spilled]
- **Flammability hazard** where hydrocarbon condensates and gas predominate
- **Scale forming on pipe leading to corrosion failure**
- **BaSO₄ scale**
- **H₂S content and potential health risk**
- **Equipment plugging**
- **Salt corrosion causing metal failure**

Discussion Questions

Discussion Questions

- 6. Are there incompatibility issues when fracing with mixed waters from different sources?**
- 7. Will the use of flowback / produced water affect the plug / perforating procedure in between frac stages?**
- 8. Are there frac equipment or downhole tubular reliability/function issues when comparing freshwater to flowback / produced water fracing?**
- 9. Are fluid dynamics such as leak-off and viscosity affected positively by flowback / produced water? Or is there a difference compared to freshwater?**

Discussion Questions

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**Oil & Grease
Soluble Organics
Chlorides
Bicarbonates /
Carbonates
Ca / Mg / Mn /
Fe / Ba / etc.**

**Scale Index Limits
Suspended Solids
Total Dissolved Solids
Bacterial Counts
pH Limits
Eh (Redox) Limits**

Water Quality Parameters and Values

Parameter	Value	Parameter	Value
Oils and Grease	No Problem	Tot Susp Solids	
Soluble Organics	No Problem	pH Limits Eh Limits	
Chlorides		Dissolved Solids	
Carbonates		Fe	
Ca / Mg / Mn		Ba	

Frac Job Expert Panel: Last Remarks

- Draft of a written summary of the Panel findings will be prepared and circulated for review and comment
- When the final draft of the proceedings are approved, the audio recordings will be erased
- Findings will be highly useful
 - Establishment of Specs for Frac Water
 - Development of criteria for water reuse systems and treatment processes

Thanks Panel!