Miscellaneous Produced Water Topics

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Topics for Discussion

- Different water issues for each type of hydrocarbon production
- U.S water volumes and management practices
- How to choose a water management option
- Induced seismicity
- Hydraulic fracturing and FracFocus

Water Issues by Production Method

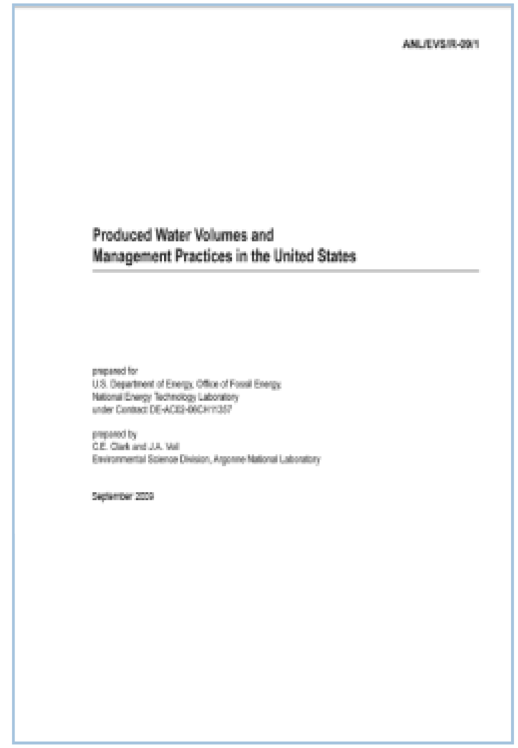
Variations in Water Needs and Generation by Production Method

Type of Oil and Gas Production	Water Needs for Production	Produced Water Generated
Conventional Oil and Gas	- Modest needs for hydraulic fracturing - More needed for enhanced recovery later on	- Low volume initially - Increased volume over time - High lifetime pw production
Coalbed Methane	- Modest needs for hydraulic fracturing	- High volume initially - Decreases over time
Shale Gas	- Large needs for hydraulic fracturing	- Initial flow rate is high, but quickly drops to very low - Low lifetime flowback and produced water production
Heavy Crude	- Steam flood to help move heavy oil to production wells	- Much of the water results from the injected steam used in steam flooding
Oil/Tar Sands	- Steam (or water) injection used in large volumes	- In-situ production methods: some water is formation water, but much is from the injected steam - Oil sand mining production methods and subsequent processing steps also generate wastewater

Produced Water Volumes and Management Practices

Detailed Produced Water Inventory for the U.S.

- Clark, C.E., and J.A. Veil, 2009, Produced Water Volumes and Management Practices in the United States.
- The report contains detailed produced water volume data for States, Federal Lands, and offshore in 2007
  - ~21 billion bbl/year
  - ~57 million bbl/day or 2.4 billion gallons/day
  - ~333 million m^3/year or 913,000 m^3/day
- The report also provides estimates of water-to-oil ratio
  - World-wide estimate – 2:1 to 3:1
  - U.S. estimate – 5:1 to 8:1
  - with more complete data sets that include TX and OK data, this would be >10:1


ANL/EVS/R-09/1

Produced Water Volumes and
Management Practices in the United States

prepared for
U.S. Department of Energy, Office of Fossil Energy
National Energy Technology Laboratory
under Contract DE-AC02-06CH11357

prepared by
C.E. Clark and J.A. Veil
Environmental Science Division, Argonne National Laboratory

September 2009

To download a copy of the report, go to:
http://www.veilenvironmental.com/publications/pw/ANL_EVS__R09_produced_water_volume_report_2437.pdf

U.S. Produced Water Volume by Management Practice for 2007 (1,000 bbl/year)

	Injection for Enhanced Recovery	Injection for Disposal	Surface Discharge	Total Managed	Total Generated
Onshore Total	10,676,530	7,144,071	139,002	18,057,527	20,258,560
Offshore Total	48,673	1,298	537,381	587,353	587,353
Total	10,725,203	7,145,369	676,383	18,644,880	20,995,174

- Onshore – 98% goes to injection wells
  - 60% to enhanced recovery
  - 40% to disposal
- Offshore – 91% goes to discharge
- Overall for U.S. – 96% goes to discharge

Disproportionate Emphasis on Shale Gas Wastewater

- Assumptions (tried to choose conservative estimates)
  - 20,000 shale gas wells are fractured in a year
  - Each frac job requires 5 million gallons
  - Only 50% of the frac fluid volume returns as flowback and produced water
- Total shale gas flowback and produced water for the U.S. = 50 billion gallons per year

Disproportionate Emphasis on Shale Gas Wastewater (2)

- U.S. produced water volume in 2007 for all oil and gas = 21 billion bbl (Source: Clark and Veil, 2009)

  = 882 billion gal/year
- Compare shale gas water to all produced water
  - 50 billion/882 billion or about 5.7%.
- Putting this in perspective, ***shale gas receives more than 90% of the attention yet it consists of less than 6% of all the volume of produced water.***

Selecting a Water Management Option

Decision Factors for Choosing a Produced Water Management Option

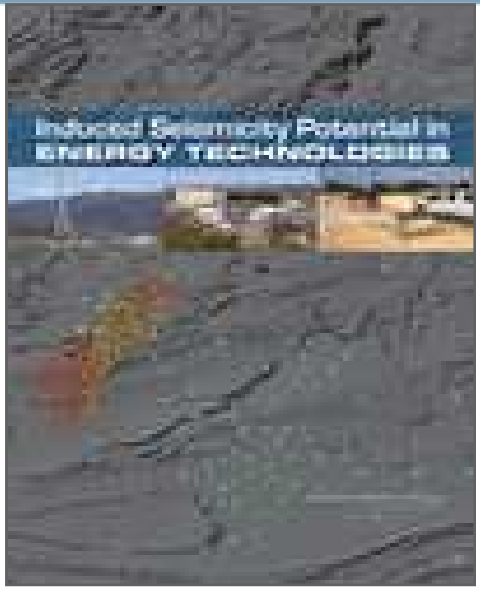
- Oil and gas companies will usually choose the lowest-cost option that:
  - Is physically practical at a location
  - Is approved by the regulatory agency
  - Is sustainable over an extended period
  - Poses little risk of long-term liability

Components Contributing to Total Cost of Wastewater Management

Category	*Cost Component (Some or all may be applicable)*
Prior to Operations	Prepare feasibility study to select option (in-house costs and outside consultants)
	Obtain financing
	Obtain necessary permits
	Prepare site (grading; construction of facilities for treatment and storage; pipe installation)
	Purchase and install equipment
	Ensure utilities are available
During Operations	Utilities
	Chemicals and other consumable supplies
	Transportation
	Debt service
	Maintenance
	Disposal fees
	Management of residuals removed or generated during treatment
	Monitoring and reporting
	Down time due to component failure or repair
	Clean up of spills
After Operations	Removal of facilities
	Long-term liability
	Site remediation and restoration

Introduction to Induced Seismicity from Energy Production

Induced Seismicity in Energy Activities



- References
  - National Academies of Science (2012)
  - Veil – two white papers prepared for GWPC in 2013
- Natural seismic events (earthquakes) occur regularly in many locations, but most of them are very small in magnitude and are not felt by humans at the surface, nor do they cause damage to surface structures
- Many of the seismic events are naturally occurring, but some can be caused by human activities. These are referred to as “induced seismicity”

Induced Seismicity from Geothermal Activities

- In general, the hazards posed by geothermal operations are not significant because project operators both inject and withdraw water from the formations, thereby keeping the formation pore pressures from climbing dramatically.
- However, constant minor tremors are often associated with such activities.
- In one noteworthy enhanced geothermal project located at Basel, Switzerland, a large water injection effort to open pathways in the hot rock caused felt earthquakes of sufficient concern to residents in that city that the project was subsequently cancelled.

Induced Seismicity from Oil and Gas Production

- Induced seismicity may occur occasionally in association with oil and gas extraction, but the number of documented cases is extremely small.
- Induced seismicity rarely occurs during enhanced recovery operations. During such operations, fluids are injected into a formation while oil and gas are withdrawn from the same formation, thereby keeping formation pore pressures from rising dramatically.
- Hydraulic fracturing involves injection of fluids at high rate for a short period of time. In nearly all cases, the potential for felt seismicity is very low, although a few cases have been observed where unique conditions were present. However, these have not led to any significant surface damage.
- The NAS report concluded that hydraulic fracturing does not pose a high risk for induced seismicity.

Induced Seismicity from Disposal Wells

- Tens of thousands of disposal wells are employed each day to inject produced water and other wastewaters into formations that are not hydrocarbon bearing. Most of these pose low risk of induced seismicity, but given the ongoing injection and cumulative formation pressure build up over time, there is some potential that disposal wells can contribute to induced seismicity. There is evidence suggesting that the number of induced seismic events has been increasing in recent years.
- Most wells are completed in areas and geological formations that are not likely to lead to induced seismicity, but several well-documented examples are described in which seismic activity was linked to disposal wells (e.g., Ohio, Arkansas, Oklahoma, and Texas). These are typically due to some geological anomalies or faults in those locations
- The relatively new concept of large-scale injection of CO_2 into underground formations as part of carbon capture and storage projects could lead to induced seismicity. The ongoing, long-term injection of CO_2 could lead to increased formation pore pressure.

Additional Findings from Recent White Paper (November 2013)

- The 2008 version of the USGS National Seismic Hazard Maps (the most recent version) does not account for many induced earthquakes. Increased hazard from induced seismicity may be included in the next update to the hazard maps, to be available in 2014. As a result, building codes may be strengthened, and insurance rates could rise.
- Some local earthquakes may be triggered by large earthquakes that occur hundreds or thousands of miles away. The seismic waves released by large earthquakes travel through the earth's crust. When conditions at a local site are primed and favorable (e.g., high fluid pressure conditions), the passing waving may generate new earthquakes.
- Some agencies and industry groups recommend the use of a risk framework that employs a stoplight approach. Injection activities are evaluated for their probability of causing earthquakes and the consequences of any earthquakes that do occur. Thresholds for risk tolerance can be set to allow operations to proceed until seismic events with magnitudes at or above the threshold are observed. At that point additional monitoring and/or cessation of injection can be required.

Additional Findings from Recent White Paper (2)

- The ability to detect and pinpoint the location of individual earthquakes and swarms of earthquakes depends to a large degree on the spacing of seismic monitoring stations and how close a seismic event occurs to a station. Most seismologists decry the shortage of existing data and stations for collecting new data.
- Most state regulatory agencies do not have regulations that focus specifically on induced seismicity. However, Ohio and Arkansas developed regulations following large earthquakes associated with disposal wells. Oklahoma is developing best practices. States are following the research.

Hydraulic Fracturing (HF)

History of Fracturing

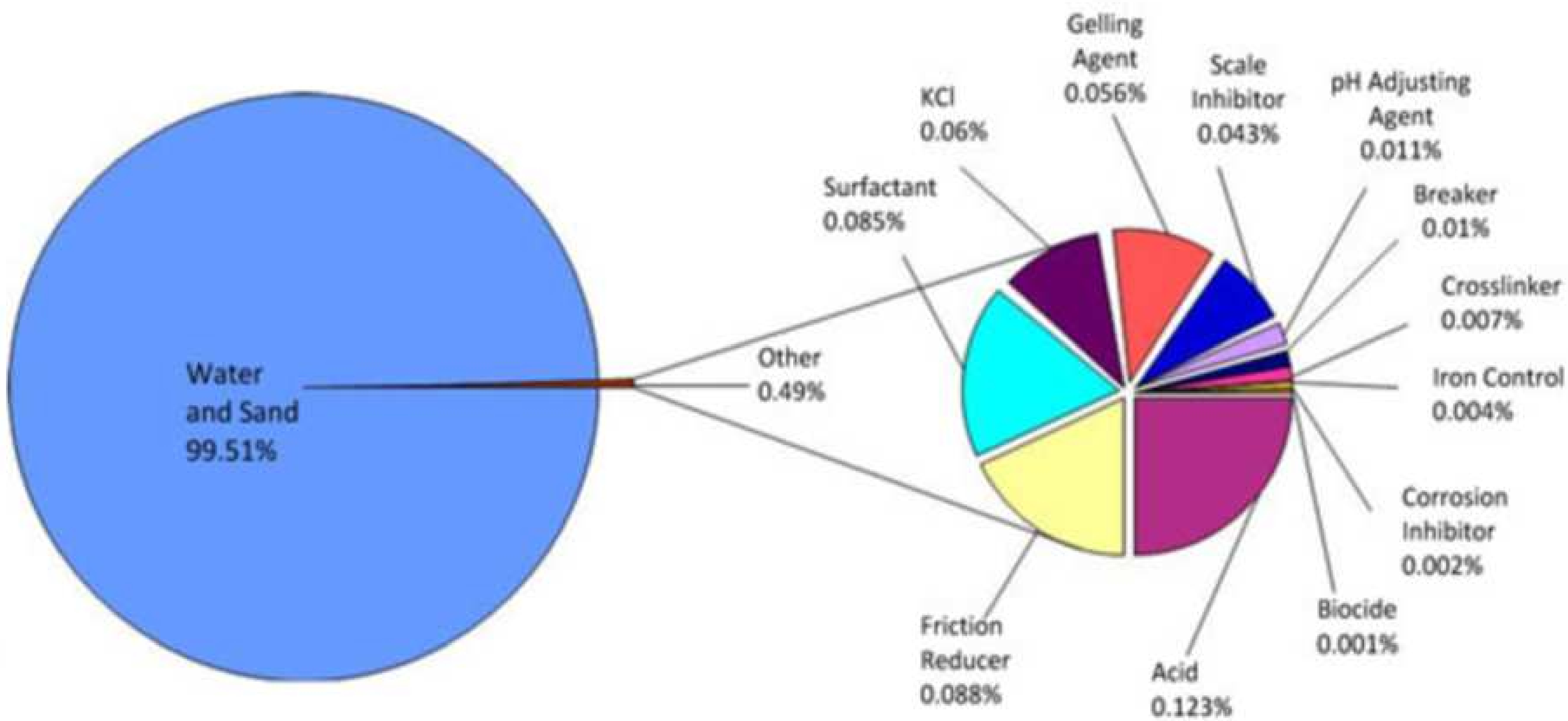
- First U.S gas well drillled in 1825 in Fredonia, NY
- First frac job (not hydraulic) in 1858 in Fredonia
  - Used black powder in multiple stages
- First commercial hydraulic fracturing job took place in 1949 in Velma, OK
- First HF of gas shale formations began in the 1980s in the Barnett Shale in Texas
- More than 1 million wells have been hydraulically fractured.
  - Few, if any, cases of environmental impact were attributed to the actual process of HF
- Use of nuclear explosions for fracturing
  - Project Gasbuggy exploded nuclear device in NM in 1967
    - Resulting gas was too radioactive to use
  - Later tests (Project Rulison and Rio Blanco) did not show good results either

Why Is HF Used?

- Shale rock is very dense and has low permeability
  - HF creates a network of small cracks in the rock that extend out as far as 1,000 feet laterally and vertically away from the well
- Virtually no shale gas wells in the U.S. would be developed unless HF is done

Frac Fluid Composition

- Water makes up ~90% of volume
- Sand makes up ~10% of volume
- All other chemical additives make up ~0.5% of volume



Source: Shale Gas Primer, GWPC and ALL

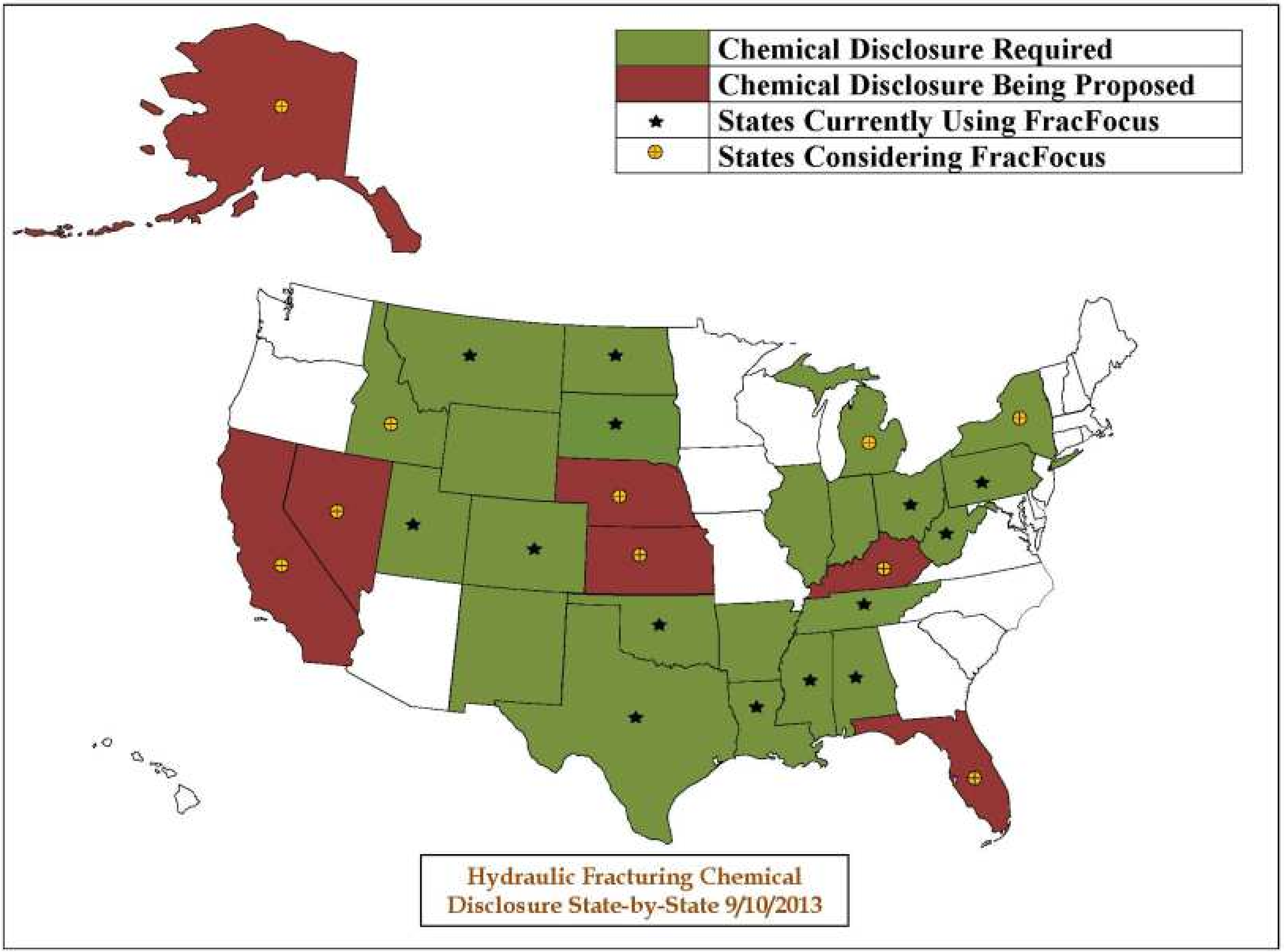
Chemical Disclosure Registry

- In April 2011, the Ground Water Protection Council (GWPC) and the Interstate Oil and Gas Compact Commission (IOGCC) opened a new online system (FracFocus) to host information about the chemical additives used in frac fluids and their ingredients
  - The key feature was a chemical disclosure registry
- Any interested person can visit the website and search for data on a specific well

www.fracfocus.org

Registry (2)

- Initially, chemical data entry into the Registry by the oil and gas companies was voluntary, but since then, many states adopted regulations requiring data on the chemicals used in frac fluids to be disclosed
  - At least 8 of those states specifically referenced FracFocus as the mechanism for submitting those data (Montana, Oklahoma, Texas, Pennsylvania, North Dakota, Colorado, Louisiana, Mississippi)
- As of mid-October 2013, data had been entered on more than 57,000 wells representing over 540 oil and gas companies



Chemical Disclosure Required
Chemical Disclosure Being Proposed
States Currently Using FracFocus
States Considering FracFocus
Hydraulic Fracturing Chemical Disclosure State-by-State 9/10/2013

Source: GWPC

Frac Focus Homepage

Example of Registry Record for Well in Texas

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by Mass)**	Maximum Ingredient Concentration in HF Fluid (% by Mass)**
Fresh Water		Carrier/Base Fluid				86.12803%
Sand (Proppant)		Proppant				12.83614%
Acid, 15% HCl	CUDD ENERGY SERVICES	Acid	Water	007732-18-5	85.00%	0.06070%
			Hydrochloric Acid	007647-01-0	15.00%	0.01071%
I-22	CUDD ENERGY SERVICES	Corrosion Inhibitor	Formic Acid	000064-18-6	60.00%	0.00053%
			Aromatic aldehyde	N/A	30.00%	0.00026%
			Haloalkyl heteropolycycle salt	N/A	30.00%	0.00026%
			Oxyalkylated Fatty Acid	N/A	30.00%	0.00026%
			Isopropanol	000067-63-0	5.00%	0.00004%
			Methanol	000067-56-1	5.00%	0.00004%
			Organic sulfur compound	N/A	5.00%	0.00004%
			Quaternary ammonium compound	N/A	5.00%	0.00004%
			Benzyl Chloride	000100-44-7	1.00%	0.00001%
SG-15M	CUDD ENERGY SERVICES	Gelling Agent	Petroleum Distillate	064742-47-8	55.00%	0.06860%
			Guar Gum	009000-30-0	50.00%	0.06236%
			Clay	014808-60-7	2.00%	0.00249%
			Surfactant	068439-51-0	2.00%	0.00249%
BUFFER H	CUDD ENERGY SERVICES	pH Adjusting Agent	Water	007732-18-5	94.50%	0.02070%
			Sodium Hydroxide	001310-73-2	51.50%	0.01128%
			Sodium Chloride	007647-14-5	5.00%	0.00110%
GB-4	CUDD	Breaker	Proprietary	N/A	100.00%	0.00120%
	ENERGY SERVICES					
CX-14G	CUDD ENERGY SERVICES	Cross Linker	Petroleum Distillate Hydrotreated Light	064742-47-8	60.00%	0.01454%
GB-2	CUDD ENERGY SERVICES	Breaker	Ammonium Persulfate	007727-54-0	100.00%	0.00083%
NE-21	CUDD ENERGY SERVICES	Non-Emulsifier	Methanol	000067-56-1	30.00%	0.01218%
			Oxyalkylated alcohols	N/A	30.00%	0.01218%
			Ethoxylated Alcohols	N/A	10.00%	0.00406%
CX-14A	CUDD ENERGY SERVICES	Cross Linker	Sodium Tetraborate	001330-43-4	25.00%	0.00056%
CS-125C	CUDD ENERGY SERVICES	Clay Stabilizer	No Hazardous Components	NONE		0.00000%
FRA-4	CUDD ENERGY SERVICES	Friction Reducer	No Hazardous Components	NONE		0.00000%
MC B-8642 (WS)	MULTI-CHEM GROUP LLC	Anti-Bacterial Agent	Glutaraldehyde (Pentanediol)	000111-30-8	60.00%	0.01180%
			Quaternary Ammonium Compound	068424-85-1	10.00%	0.00197%
			Ethanol	000064-17-5	1.00%	0.00020%
MC S-2510T (WS)	MULTI-CHEM GROUP LLC	Scale Inhibitor	Ethylene Glycol	000107-21-1	60.00%	0.00605%
			Sodium Hydroxide	001310-73-2	5.00%	0.00050%

Chesapeake Resources Well BSOA 14-14-15 H-1, De Soto County, LA, frac date 3/21/11

Conclusions and Final Thoughts

- There is a lot of produced water generated each year
- Management of that water must be practical and comply with regulations
- Discharge is not allowed at most onshore wells but is used commonly for offshore wells
- Most of the produced water in the U.S. is injected
  - 60% for enhanced recovery
  - 40% for disposal
- Hydraulic fracturing is common, well-established, and poses little risk
- Oil and gas production, enhanced recovery, and hydraulic fracturing pose very small risk of induced seismicity
- A few disposal wells have triggered induced seismic events that were felt by people at the surface