EPA Hydraulic Fracturing Workshop, February 24-25, 2011, Workshop 1, Chemicals

Tracking Fracture Fluid Movement with Chemical and Gamma-Emitting Tracers with Verification by Microseismic Recording

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Sources of Tracing and Monitoring Data

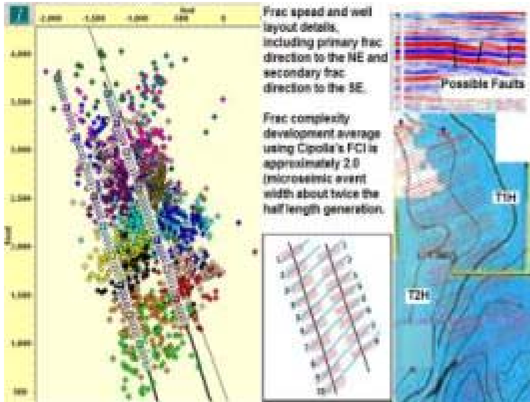
Data Sources – Pre Completion

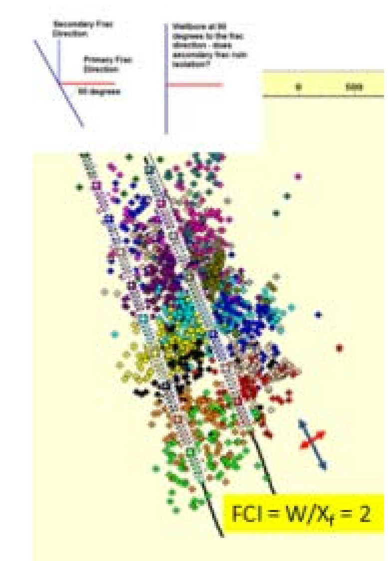
- 3-D seismic
- Geological structure map
- Petrophysical Evals
- Drilling / Logging
- Mud-Logs & Gas Shows
- Offset well production

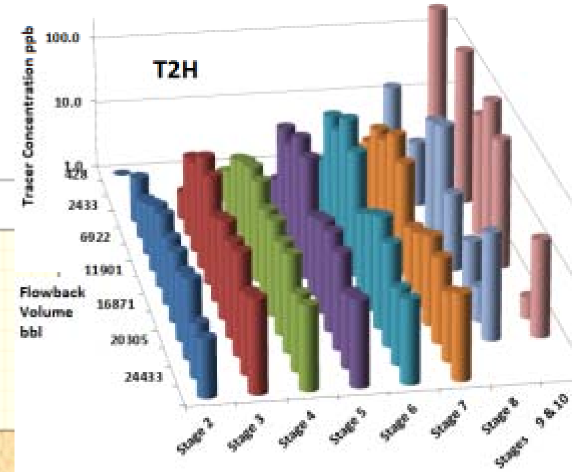
Data Sources – Frac & Post Frac

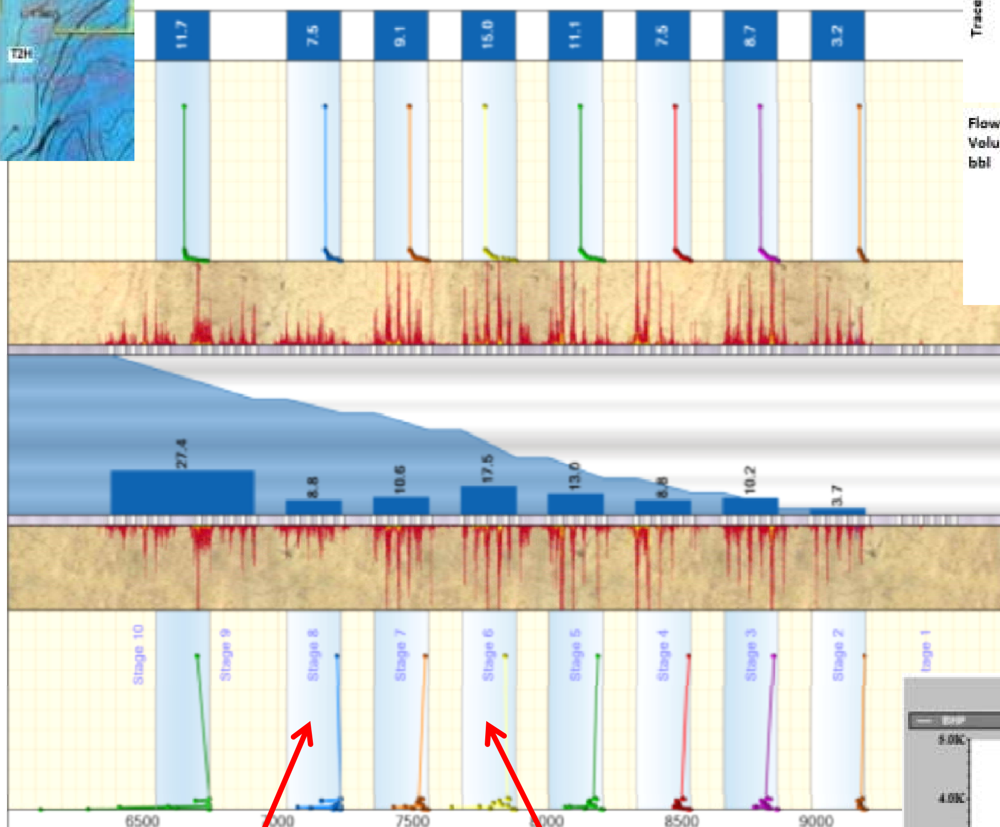
- Frac pump record match to Microseismic
- Low-level gamma tracer-marking of prop
- Fluid tracers in backflow
- Recovered brine salinity, vol, rate & ion analysis
- Production response (IP, EUR, Fluids and changes

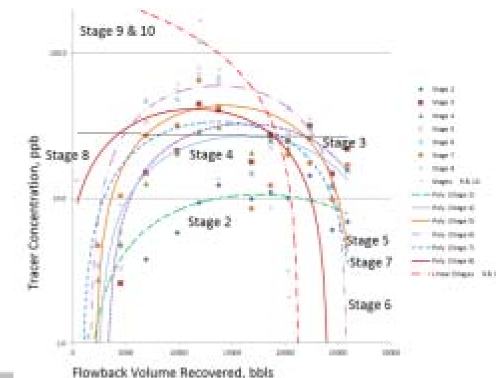
Using All The Data to Help Understand The Frac Behavior.

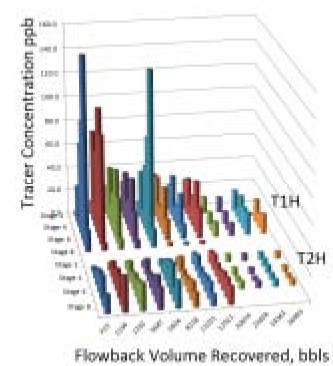


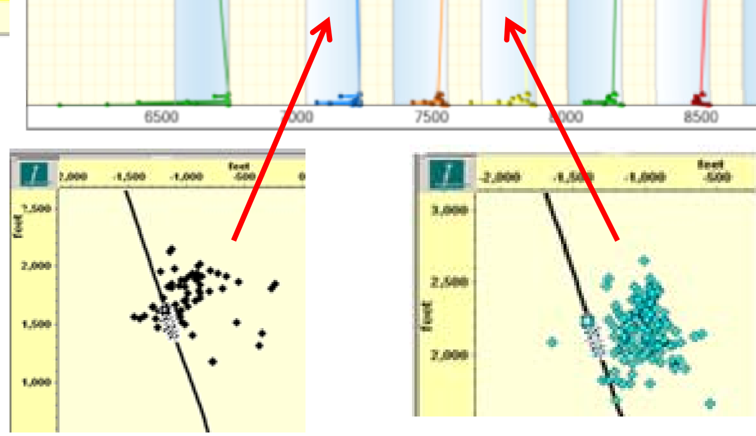


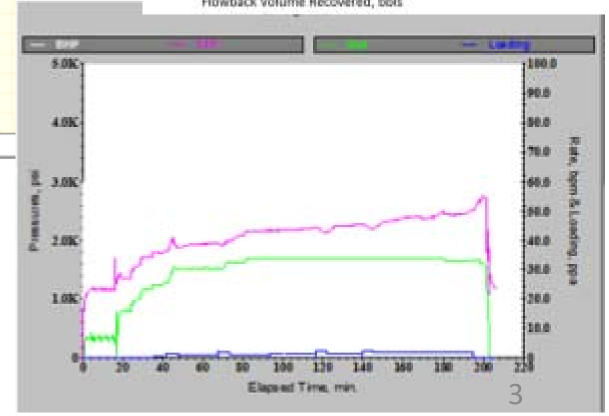


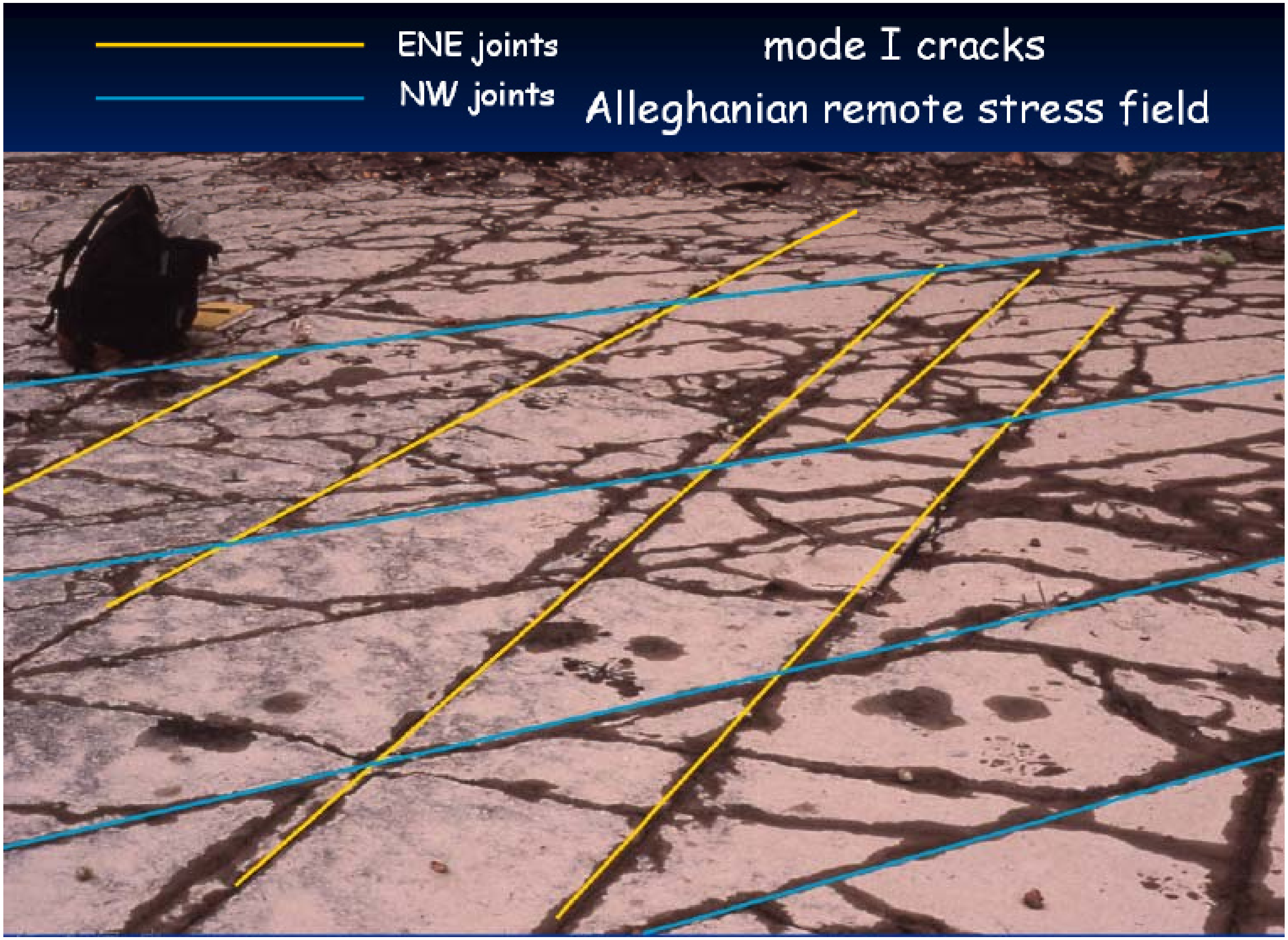












Gary Lash – SUNY, New York

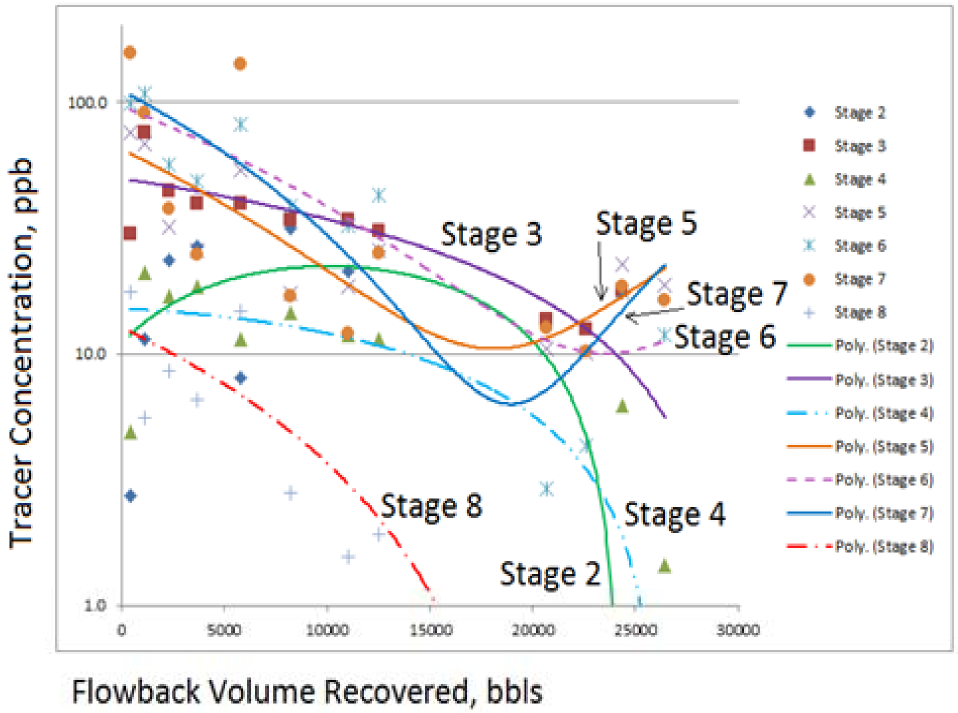
Tracers

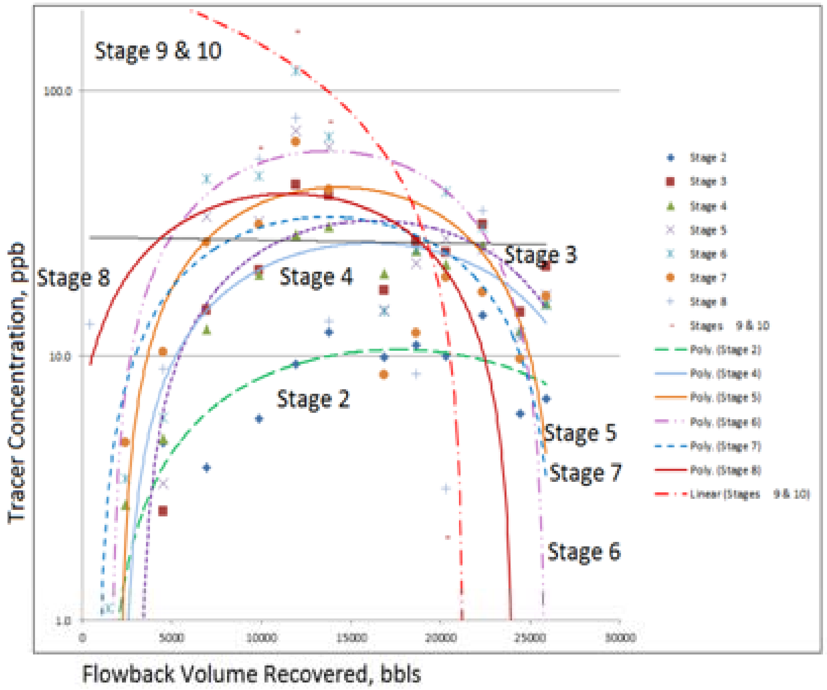
- **Chemical Tracers**
  - Which zones flow – Long term stability – Intermittent?
  - Extraneous water entry
  - Well-to well interference
  - Complexity development?
- **Gamma-Emitting Tracers,**
  - Where fracs initiate & did diversion work?
  - Transverse or Longitudinal? – careful!
  - Frac-to-frac and well-to-well interference
  - Secondary Frac initiation?

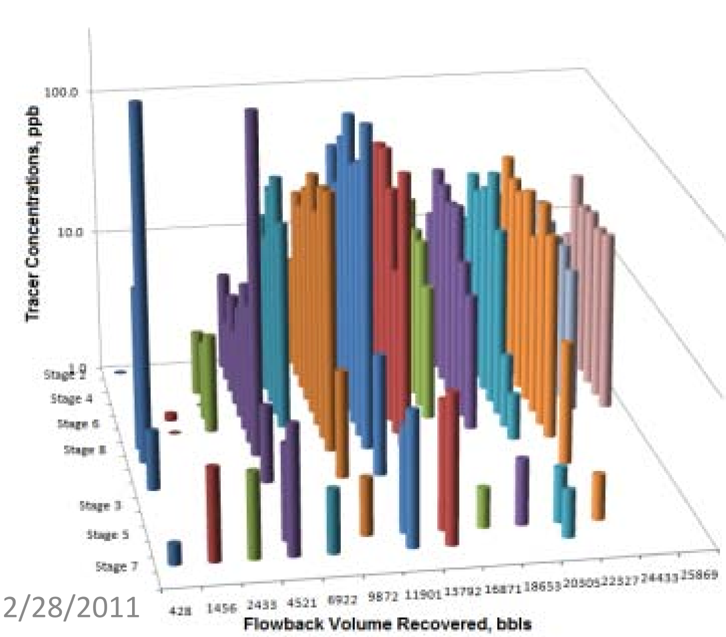
Tabular Form – What does it tell you?

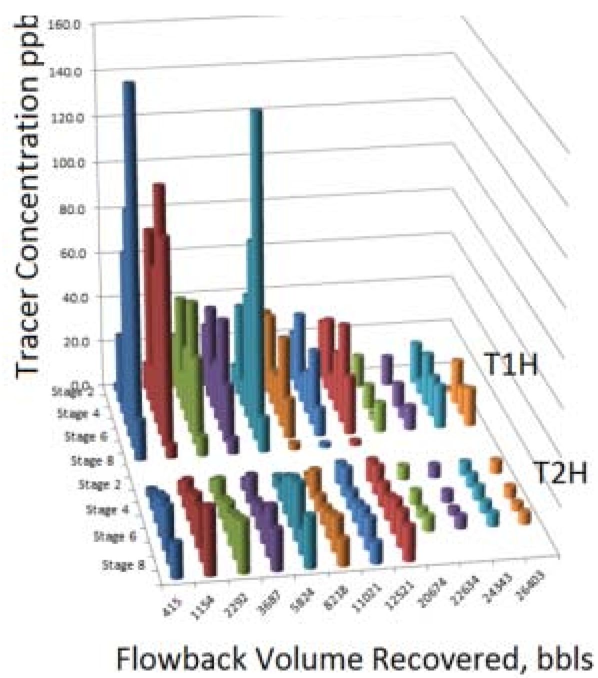
Chemical Tracer

	T1H							
	Stage 2	Stage 3	Stage 4	Stage 5	Stage 6	Stage 7	Stage 8	
Flowback bbl	CFT 1200	CFT 1400	CFT 1500	CFT 1600	CFT 1700	CFT 1300	CFT 1800	CFT Total ppb
415	2.7	29.9	4.9	75.6	98.4	155.0	17.5	384
1154	11.5	76.0	21.1	68.8	108.1	90.6	5.6	382
2292	23.5	44.5	17.0	32.1	56.9	37.6	8.6	220
3687	26.9	39.5	18.6	25.9	48.4	24.9	6.6	191
5824	8.0	39.5	11.4	53.7	82.1	141.1	14.9	351
8218	31.8	34.3	14.6	17.4	38.8	17.0	2.8	157
11021	21.2	34.1	12.0	18.5	32.4	12.1	1.6	132
12521	25.4	31.0	11.4	25.9	42.9	25.1	1.9	164
20674	0.0	13.7	0.0	10.5	2.9	12.6	0.0	40
22634	0.0	12.5	0.0	10.1	4.3	10.3	0.0	37
24343	0.0	17.8	6.3	22.6	17.5	18.5	0.0	83
26403	0.0	0.0	1.5	18.8	11.9	16.4	0.0	49
Average ppb	10.9	26.6	8.5	28.1	40.1	42.1	4.2	
% ppb from stage	6.8%	16.6%	5.3%	17.5%	24.9%	26.2%	2.6%	
total ppb at last sample	0.0%	0.0%	0.0%	23.3%	25.5%	51.2%	0.0%	

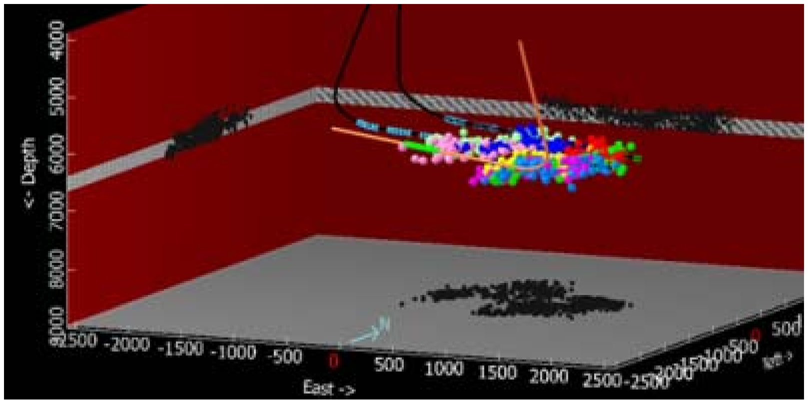

Tracer Concentration, ppb
Flowback Volume Recovered, bbls
Stage 3
Stage 5
Stage 7
Stage 6
Stage 8
Stage 4
Stage 2
Stage 2
Stage 3
Stage 4
Stage 5
Stage 6
Stage 7
Stage 8
Poly. (Stage 2)
Poly. (Stage 3)
Poly. (Stage 4)
Poly. (Stage 5)
Poly. (Stage 6)
Poly. (Stage 7)
Poly. (Stage 8)


Tracer Concentration, ppb
Flowback Volume Recovered, bbls
Stage 9 & 10
Stage 8
Stage 4
Stage 3
Stage 2
Stage 5
Stage 7
Stage 6

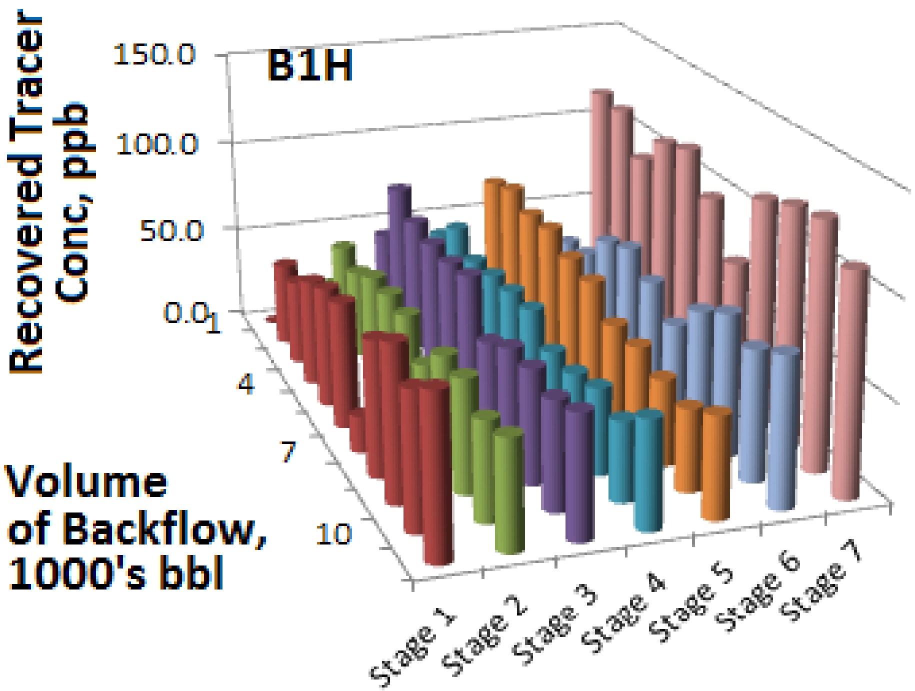

Tracer Concentrations, ppb
Flowback Volume Recovered, bbls

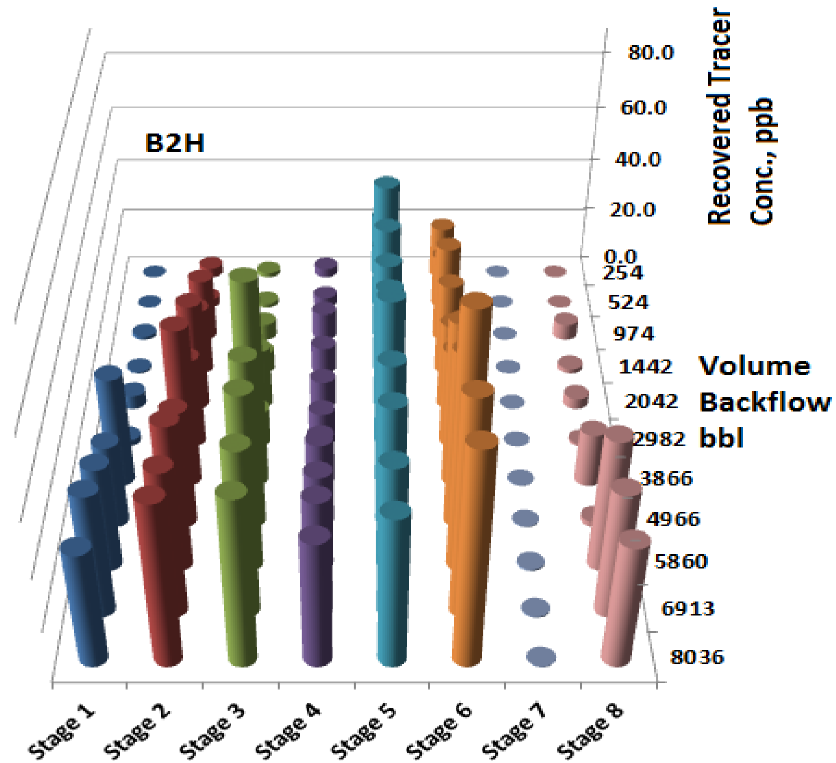

Tracer Concentration ppb
T1H
T2H
Flowback Volume Recovered, bbls

Flow Back on Sequential Fracs

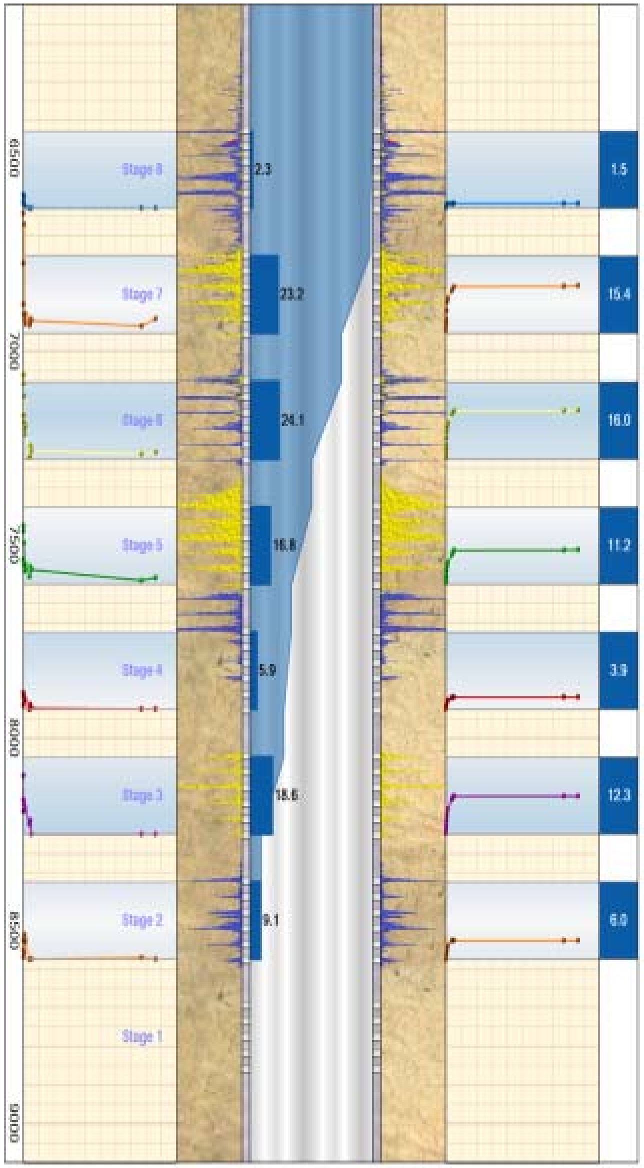


What happened to stage 7?
Bit of a mystery!





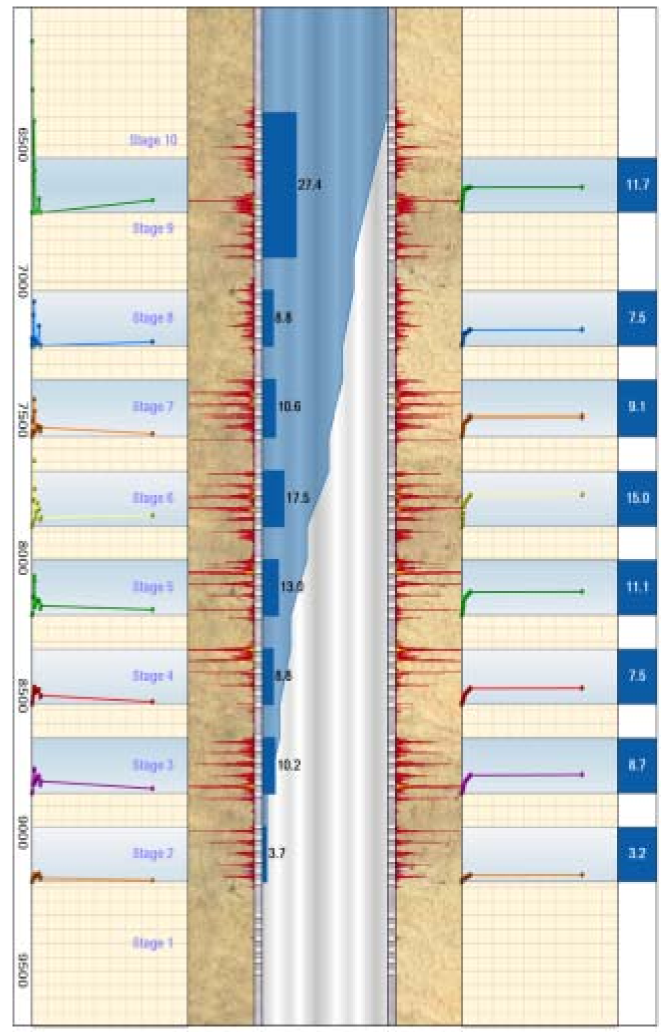
Combined Tracers as a Production Log



Shaded area in Fig center is contribution of each stage to the flow as calculated from mass balance.

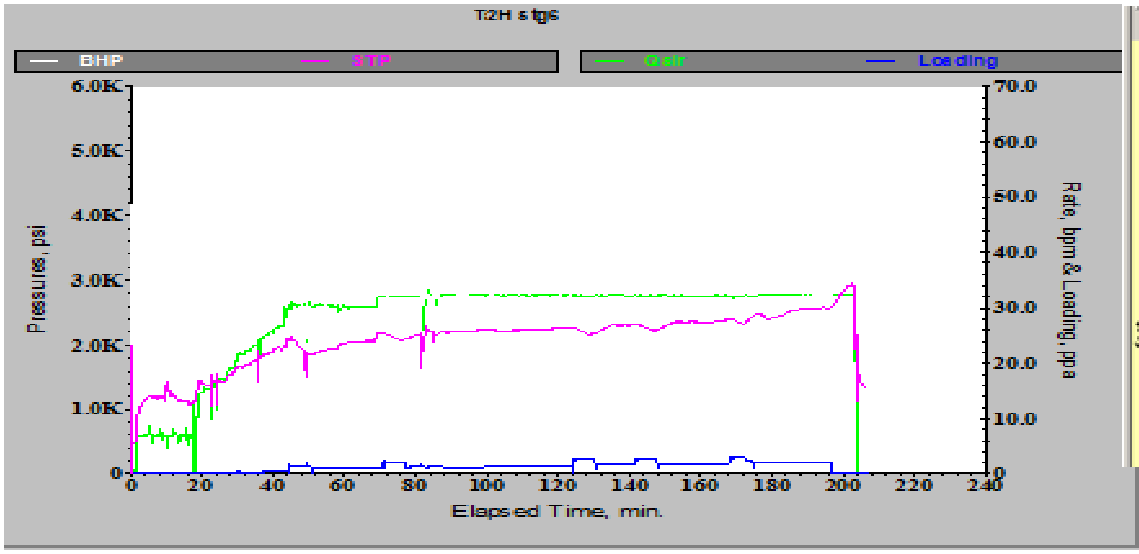
Fluid tracer conc. in back flow against vol prod (left side of fig) _ est. comm. of frac w/ wellbore & how connection changes over time or volume produced.

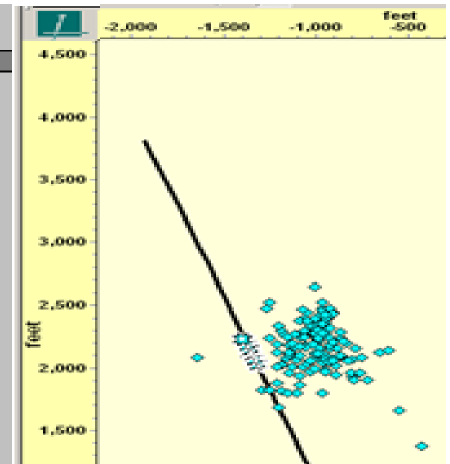
Right side of fig is amount of fluid tracer recovered from each traced stage and is a reflection of the amount of traced load fluid actually recovered.

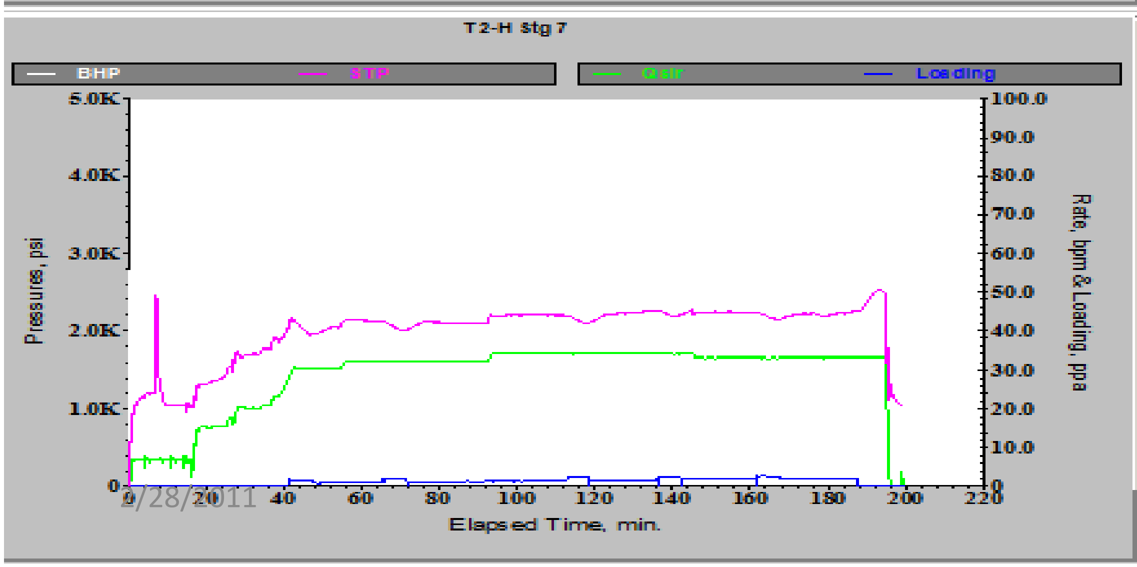


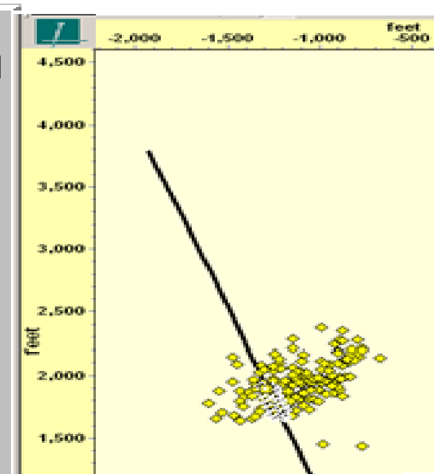
SPE 140105

Reaction of the frac reflected in the Pumping Record



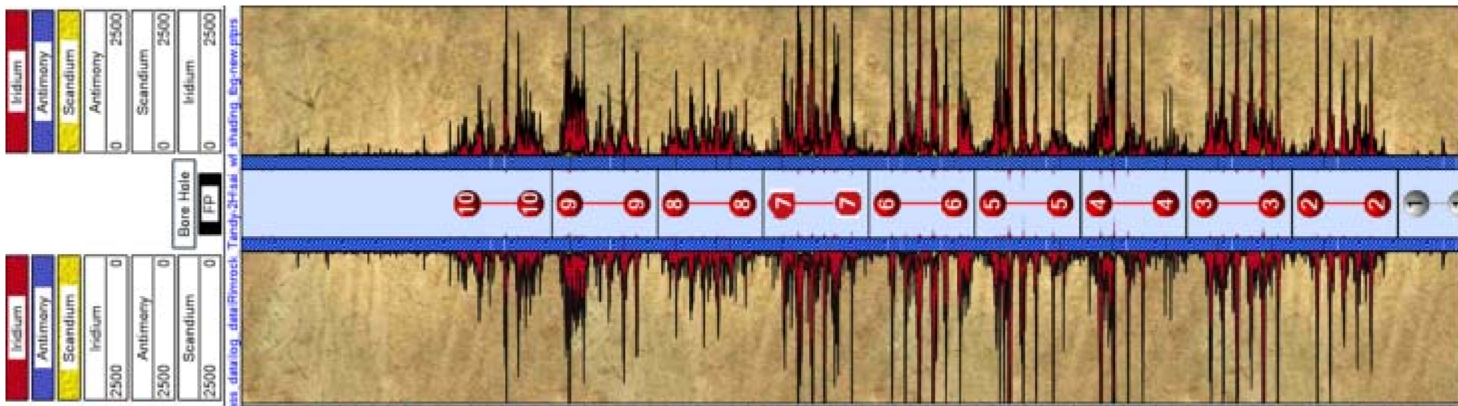






SPE 119896

Tracers
Effect of increasing complexity



Key
>200
150 to 200
100 to 150
70 to 100
50 to 70
35 to 50
25 to 35
17 to 25
12 to 17
8 to 12
5 to 8
3 to 5
2 to 3
1 to 2
0.05 to 1

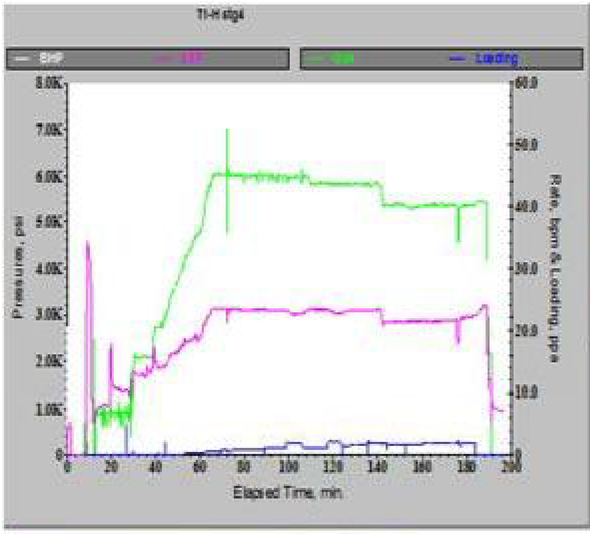
Flowback bbl	Stages 9&10 CFT 1000	Stage 8 CFT 1100	Stage 7 CFT 1900	Stage 6 CFT 2500	Stage 5 CFT 2400	Stage 4 CFT 2200	Stage 3 CFT 2100	Stage 2 CFT 2000
428	312.4	13.2	0.0	0.0	0.0	0.0	0.0	0.0
1456	0.0	0.0	0.9	1.1	0.0	0.0	0.0	0.0
2433	0.0	0.0	4.7	3.4	0.9	2.7	0.0	0.0
4521	224.3	9.0	10.4	5.9	3.3	4.9	2.6	4.7
6922	0.0	0.0	26.8	46.9	33.7	12.7	14.9	3.8
9872	61.0	55.5	31.4	47.9	32.2	20.3	21.2	5.8
11901	166.5	79.7	64.4	119.3	70.9	28.8	44.3	9.3
13792	76.5	13.6	42.5	67.6	61.9	30.8	40.3	12.3
16871	0.0	0.0	8.5	14.8	14.9	20.6	17.8	9.9
18653	0.0	8.6	12.2	25.4	22.4	25.2	27.2	11.0
20305	2.1	3.2	19.8	41.8	27.9	22.2	24.7	10.0
22327	25.4	35.5	17.4	30.5	25.3	26.3	31.4	14.2
24433	0.0	0.0	9.8	12.2	11.7	12.6	14.7	6.0
25869	0.0	0.0	16.8	15.6	17.0	15.8	21.8	6.9
26654	23.1	7.0	5.5	20.0	9.9	4.0	8.2	1.9

Avg ppb	15.7	3.9	9.0	11.7	10.1	8.0	10.2	3.4
% total ppb from Stage	8.2%	2.1%	4.7%	6.1%	5.3%	4.2%	5.3%	5.3%
% total ppb @ last sample	28.2%	8.6%	6.8%	24.5%	12.2%	4.9%	10.1%	2.4%

Conclusions - Microseismic

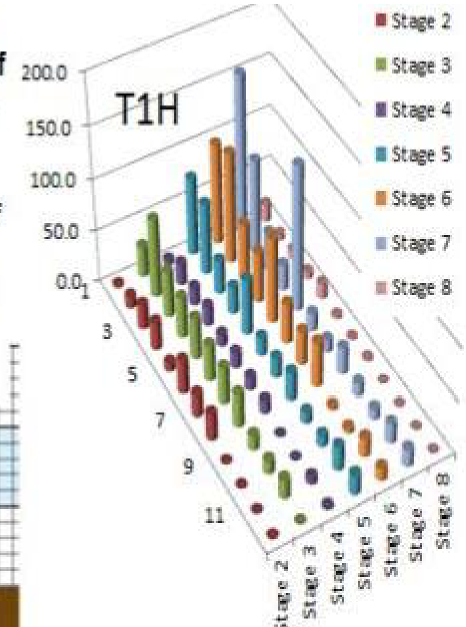
- Potential shape and volume of SRV (stimulated rock volume)
  - Hydraulic connection?
  - Fault location & actuation warning
  - High and low breakout
  - Frac cloud direction
- Tracer confirms complexity and fluid sources during recovery

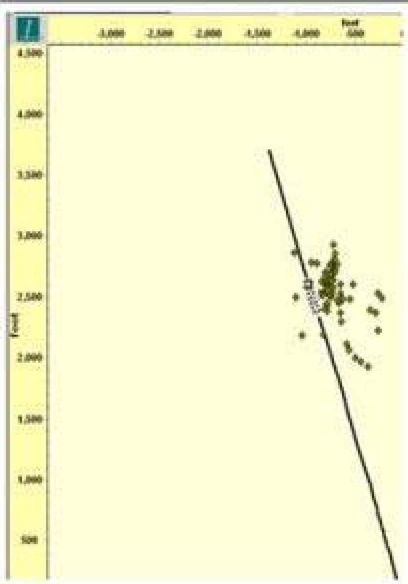
Poor Complexity – Tracer Returned Quickly

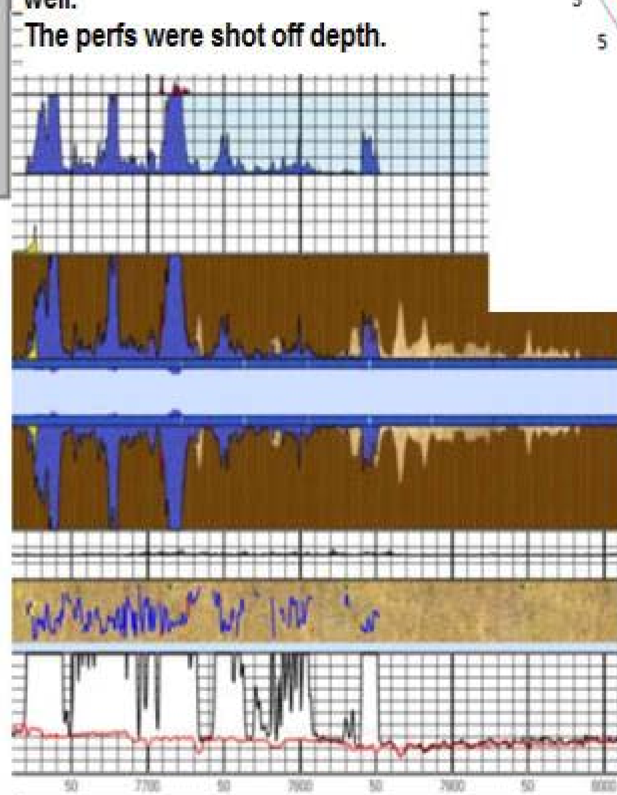


T1H - Stage 4. Transverse fracs are indicated, but only a minor amount of microseismic events were recorded. The chemical tracer flow from this stage was marginal with very little production after about 10,000 bbls of water. There is a small amount of proppant interference from the T2H well.

The perfs were shot off depth.



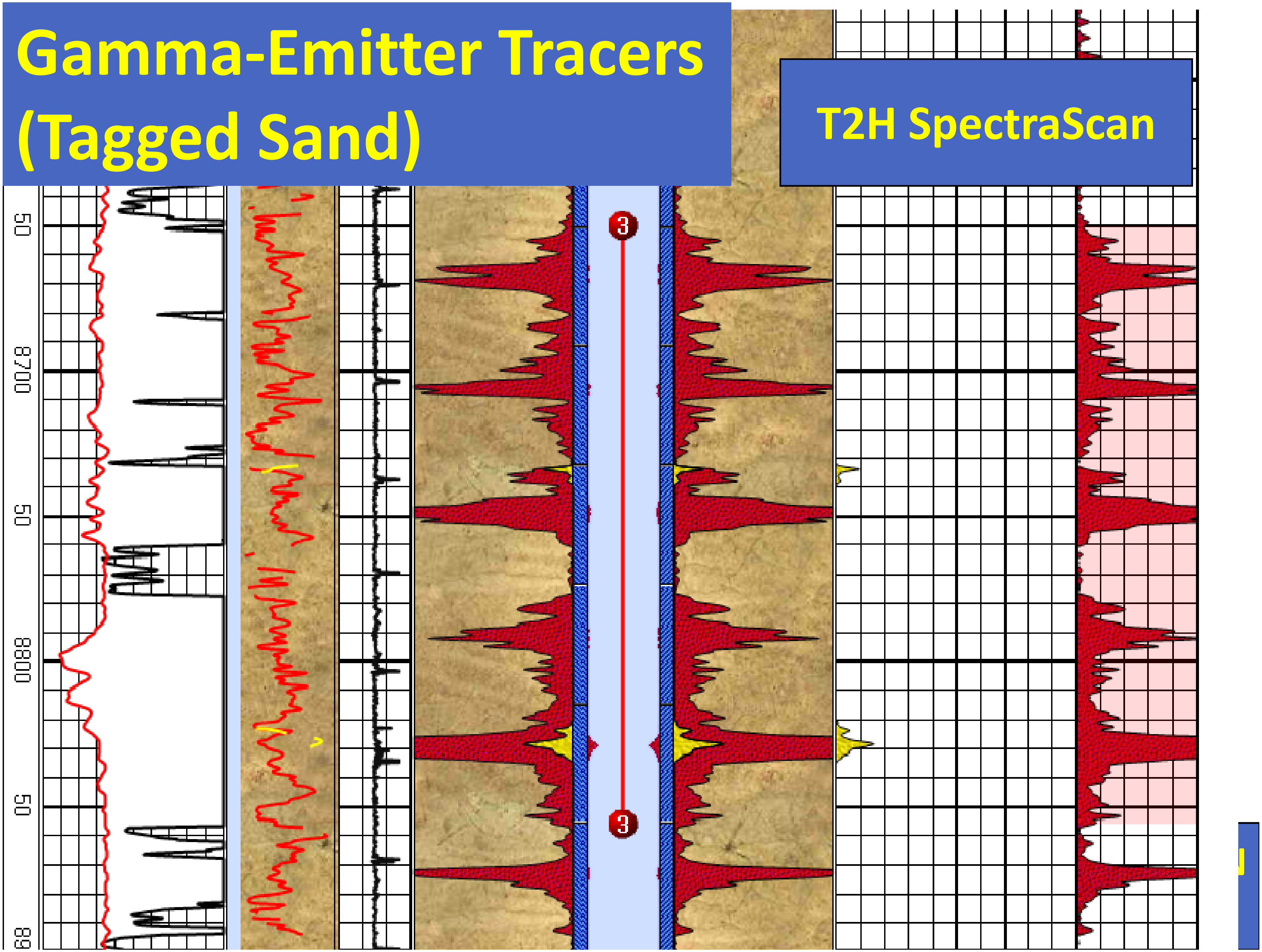




The Tracer showed several cases of the perfs being off depth from the original

Gamma-Emitter Tracers (Tagged Sand)

T2H SpectraScan



Conclusions

- **Chemical Tracers are a very effective tracking resource for identifying sources of fluids recovered over periods of 1 year in some cases.**
- **Combining monitoring and tracing methods is a powerful tool for understanding fracs in a new area.**

Tracking Fracture Fluid Movement with Chemical and Gamma-emitting Tracers with Verification by Microseismic Recording

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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.

Chemical tracers, gamma-emitting tracers, microseismic (acoustic monitoring of small breakage sounds made by the rock during fracturing) as well as other simple measurements during and after fracturing can be very useful in describing hydraulic fracture development. The output from such monitoring can supply information on fracture complexity, frac conductivity, height growth, frac barrier effectiveness, well-to-well and frac-to-frac interference, water entry points and general fracturing execution.

This work focuses on both the "certainty" of the data (and sources) and the linkages between measurements with the intent to improve understanding of both the reliability of the data and the unknowns that can be addressed, either in part or in full, by the collected data.

Frac optimization begins with understanding the elements that control the placement and flow behaviors in a well. High permeability, conventional reservoir rocks basically have one-factor-dominated systems of porosity, permeability and fluid saturations. Such formations are relatively easy to describe in numerical units that yield to reservoir models and predictive behavior. As formation grain size, permeability and porosity reach the values in the rocks classified as potential-productive "shales", the permeability drops into the 100's of nano-Darcies. Effective, interconnected porosity may exist in fractures, interstitial portions of the fine-grained rock matrix and in openings within the kerogen, created by shrinkage and alternation of the organic content during maturation and subsequent hydrocarbon expulsion. As shale forms gas storage and flow structures, the rock fabric becomes radically different from convention reservoirs with natural fractures and weak zones within the fabric offering potential for complex fracturing and very unusual fluid behavior.

Field data sets are rarely perfect or complete, so having a number of data sources and an understanding of the type of information that can be drawn from often disparate data sources plus the level of accuracy possible from these measurements is very useful. The sources of information in well work may include:

- 3-D Seismic is well known for identification of geologic hazards, but is also important in combination with overlays of microseismic, micro-losses of mud and frac breakdown pressures to identify natural fracture locations.
- Geological structure mapping is valid for locating structures, reefs and areas of uplift that may be associated with increased incidence of natural fractures.

- Shale fabric considerations are part of the wider reaching candidate and sweet-spot identification as well as evaluation of interconnection of shale variables such as mineralogy, multiple porosity types and natural fracture occurrences.
- Frac Design and Pumping Records – pumping behavior (pressure, rate, loading) frequently raise questions about what is happening in frac initiation, frac extension and overall frac growth. Some frac analysis, either during or post frac, have been accepted in shale fracturing while others are of questionable use in the ultra-low permeability shales where most fluid loss is through the fractures in pressure dependent leakoff.
- Microseismic with pressure, rate and prop loading matched to the event time is a useful tool for tracking shear fracturing events that are common in many shale fracs where natural fractures open and form the flow paths and the extensive fracture-to-formation contact areas necessary for shale development. Microseismic is commonly used to describe the stimulated reservoir volume (SRV) in shales. Low-level gamma energy tracer-marking of proppant has developed many uses and supplies conformation of frac initiation points, near wellbore isolation between fracs in multi-frac wells, verifies frac diversion, proppant interference from frac-to-frac and even well-to-well on moderately closely spaced wells.
- Chemical tracers in the backflow from both stimulated wells and offset wells have been utilized for tracking water return from individual stages, polymer clean-up, well-to-well frac interference and possibly helping confirm complex fracture development.
- Recovered brine salinity, volume and ion analysis describe the return of frac fluid, the amount of mixing between frac water and shale connate fluids at time of sampling. Care must be exercised with this technology since single data points are often skewed by irregular flow patterns of the well (e.g., slugging). Using the data as a trend over time is the only accurate use.
- Production logging can be the final word on production from each frac stage; however, flow in horizontal wells is complex and examples of active production and simultaneous counter-current flow (into the well) are well described in both physical simulators and actual wells. Correct application of this technology is very valuable to identification and quantification of fluid entry and exit points.
- Production plots contribute significantly to evaluation of overall frac performance in a well-known area and as a piece of data in evaluating new areas.

Tracing Examples

One of the first necessities is to lay out the wall path with as much support information as possible. Figure 12 illustrates such a layout with well path, structural impacts, faults below and possibly through the play, the potential well-to-well linkage from expected frac direction, and comparison of frac behavior of offset wells.

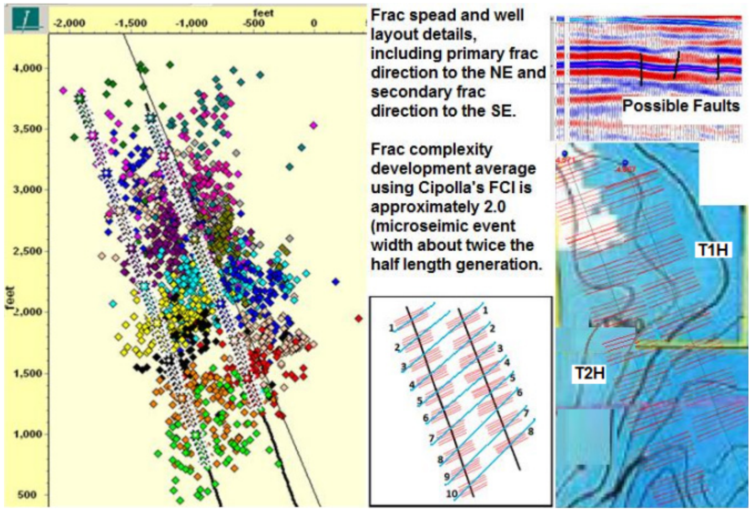

Figure 12. A sequential or zipper fraced well pair in Tier 2 of the Barnett was drilled in a NNW direction in an area with possible faulting in the Ellenberger (immediately below the Barnett) with general primary frac direction of NE/SW. Well T1H has 8 stages; well T2h has 10 stages. Each stage was approximately 200,000 lb 100 mesh sand (1000 lb/ft); 7400 bbls water (40 bbls/ft of lateral); 6 perf clusters per frac stage; 1 bpm/perf; design frac rate was 50 bpm.

In this first example case, the available assessment information includes chemical fluid tracer (CFTs), proppant tracers ("100" mesh sand), microseismic monitoring and frac pump charts. The initial production or IP (24 hr) was 2.3 mmscf/d in the T2H and 1.0 mmscf/d in the T1H.

The first post-drilling information is usually the frac treatment pressure response, Figure 13. The break in pressure in stage 1 after about an hour on the T2H well was unusual, but the microseismic showed that the events were still solidly in the target zone, although frac direction had changed.

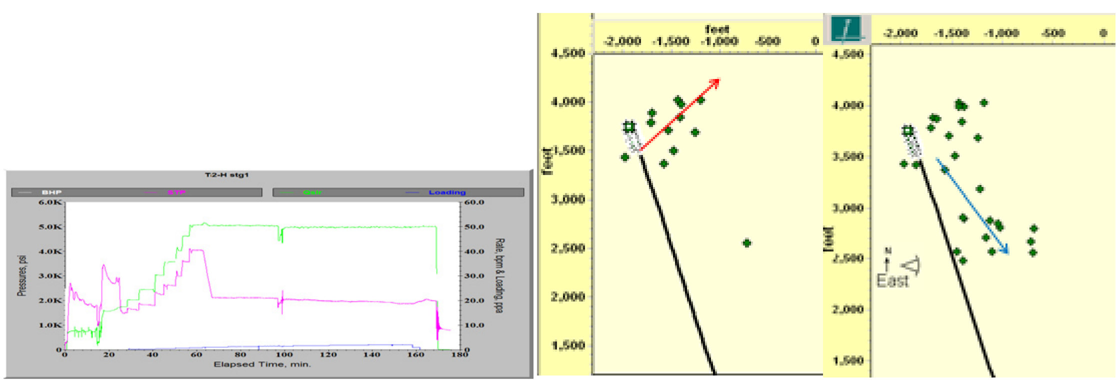

Figure 13 shows an unexplained pumping pressure break at about 60 minutes.

Fracture initiation pressure (breakdown) is low in this area and is marked by frequent frac direction switching along the natural fractures as often captured by the microseismic. The technique of ramping up slowly was common to allow the frac to open natural fractures and initiate active complex fracturing. This avoided both planar fracturing and breaking out of zone (important to avoid the salt water containing Ellenberger formation below the Barnett). Stage 1 (the toe stage) on the T1H well exhibited nearly the same behavior, Figure 14.

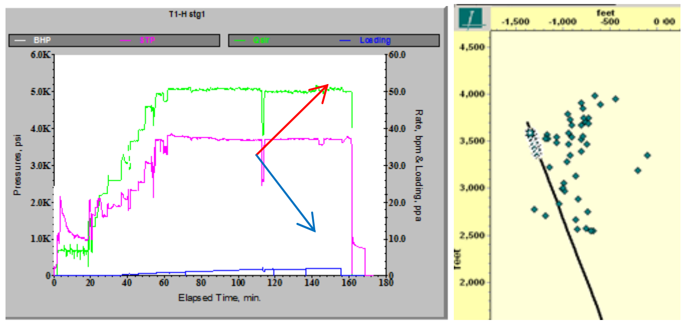

Figure 14. Near identical primary and secondary frac behavior on the T1H stage 1. The breakout pressure shift was hidden in the ramp up but occurs at about 45 minutes.

Flow back monitoring of returning frac and formation fluids was accomplished with chemical tracer monitoring and a logging run to measure the gamma levels along the wellbore. Results are in Figure 15.

Other Information Sources

Surface Treating Pressure (STP) is one source of information that is always available. Understanding the pressure relationship to down-hole events is never an exact method, but there are many cases where this surface information does have a strong linkage to demonstrated events. The closest agreement is often generated in a field-specific study and demonstrated knowledge of the geologic area. One example is the behavior of the net pressure development (rate of increase or decrease) during the fracs. This data has been more useful in specific shales such as the Barnett than any other conventional or unconventional formation (King, 2008; King, 2011).

The earliest data from the frac is the breakdown and the well's reaction to the increases in rate and proppant. Increasing the rate after the initial breakdown in increments of 5 to 10 bpm was recognized as a way to keep the frac in zone, first in the Devonian shale and later in the Barnett Shale (Yost, 1988; King, 2008; King, 2010). The explanation then and now is that the incremental increase gives the natural fractures time to break down and start the initial complexity development. After breakdown, every incremental increase in rate brings a sharp rise in pressure followed by a sharp drop grading into an attenuated decline as the fracture opens and reaches a steady leakoff rate. Notice that the declines in pressure become shallower and less in total in the later stages of rate increase. This is the effect of hydraulic diversion as friction through the perforations begins to control the flow rate into the subject perforations.

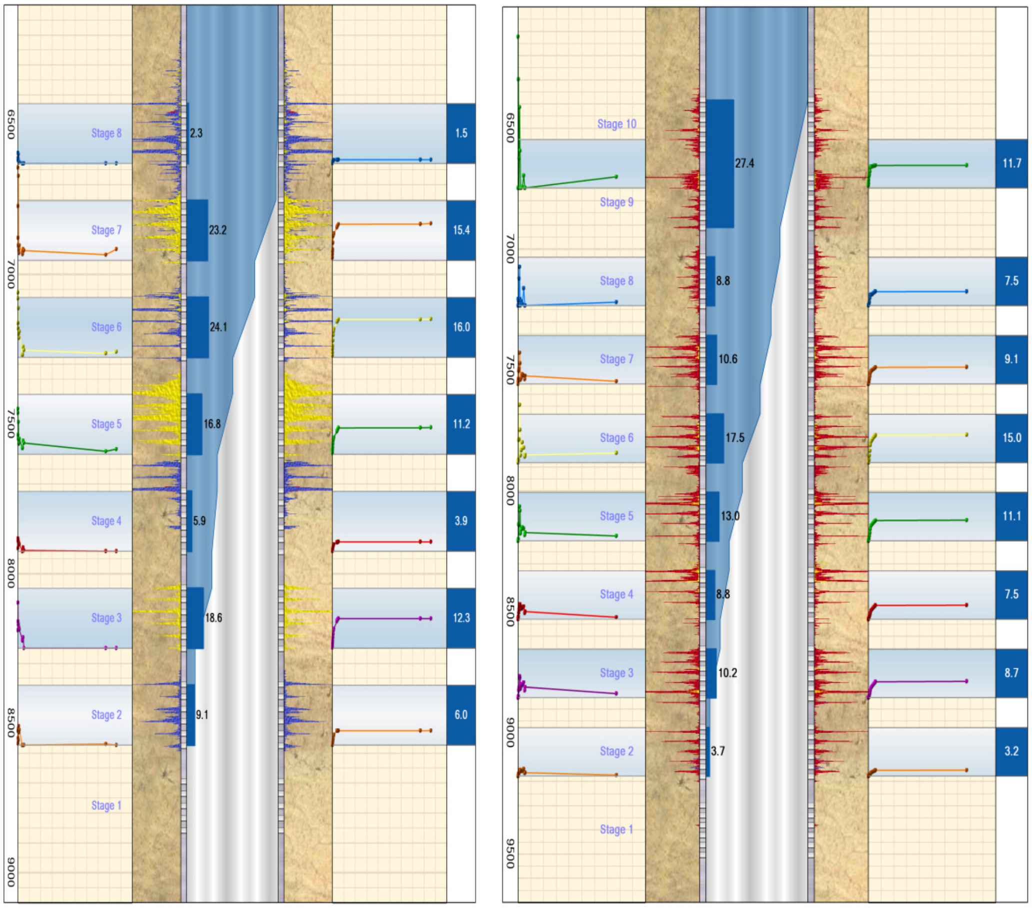

Figure 15 for T1H (left) and T2H (right) are the mass balances of fluid tracer flow coupled with information on frac breakdown from proppant tracer. The information from fluid tracing shows CFT concentration measurements in the backflow against volume produced (left side of each figure) are useful for estimating communication of the frac stage with the wellbore and how that communication changes over time or volume produced. The left side of each figure is the amount of initial fluid tracer recovered from each traced stage and is a reflection of the amount of traced load fluid actually recovered. The shaded area in the center is the contribution of each stage to the flow as calculated from the mass balance.

Selected References

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