Optimizing Stimulations and Completions Using Fracture Diagnostics

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Pinnacle – A Halliburton Service
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Outline

Monitoring Technologies
- Microseismic
- Validation Experiments
- Microdeformation (Tiltmeter)
- Distributed Temperature Sensing (DTS)

Example Applications
- General Shale Applications
- Specific Eagle Ford Applications

Goal
use monitoring to Optimize:
- Field
- Completions
- Stimulations
Pinnacle Microseismics: Over 13,000 Fractures Mapped
Downhole Microseismic Monitoring

Observation Distance Depends on Seismic Attenuation

Array of 3C Receivers

Microseismic Monitoring Is Applied Earthquake Seismology (Seismology 101)
- Based On Principles Known For Decades
- Has Been Used Since Mid-1970’s (Hot Dry Rock)
- Primary Difference Is The Use Of A Downhole Array
Receiver Arrays

**Typical Array**
- 12 levels
- 400 ft to 1000 ft array
- Typically up to 24 sondes
- Large number of receivers
- Fast sample rates

**Enhanced Array**
- Stacked levels
- Two or more stacked sondes

**Multiple Array**
- Two or more time-synced monitor wells
- Up to 24 sondes per well

**Horizontal-well array**
Microseismic Processing – Locations

- Slow Layer
- Fast Layer
- Very Slow Layer

- Predetermined calibrated velocity model

- P-S Separation
- P Moveout
- S Moveout

- Polarization

- 2D Location

- 3D Location
Velocity Model – Microseismic Location

Determining the velocity structure is the most critical element of microseismic modeling

- Start with dipole sonic log
  - Good resolution
  - Wrong velocity (vertical)
- Perforation Timing
  - Obtain shot time
- Optimization
  - Minimize residuals and location errors
- Integrate all data

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Tiltmeter fracture mapping - measuring deformation

Surface
- Fracture monitoring reconnaissance tool (azimuth & dip)
- SRA (shales)
- Reservoir monitoring

Downhole
- fracture dimensions

“Watching the earth move”
Surface Tilt Mapping
Surface Deformation for Fractures with Different Orientations

- **Vertical**: Dip = 90
  Maximum Displacement: 0.00026 inches

- **Horizontal**: Dip = 0
  Maximum Displacement: 0.0020 inches

- **Dipping**: Dip = 80
  Maximum Displacement: 0.00045 inches
Tilt vector maps: vertical & horizontal fractures

Measured Tilt: 250 nanoradians
Theoretical Tilt: 250 nanoradians
Frac: Vertical Azimuth: N39°E Dip: 87° W Depth: 2300 ft

Measured Tilt: 500 nanoradians
Theoretical Tilt: 500 nanoradians
Frac: Horizontal Azimuth: N/A Dip: 6° N Depth: 2900 ft
Integrated Microseismic / DTS Monitoring

Rationale

- Microseismicity provides far-field fracture behavior
- Difficult to determine details of the completion effects
- Distributed Temperature Sensing (DTS) can bridge that gap in understanding
  - Fiber-optic technology to determine temperature along the entire wellbore
  - Capable of detecting a temperature change event of 0.01°C
  - Spatial resolutions as high as 1 meter
DTS Deployment Options

Wireline (Retrievable)
- Surface Casing
- Production Casing
- Fiber Optic Cable
- Tubing
- Bottom Hole Gauge Carrier with PT Gauge

Tubing (Permanent)
- Surface Casing
- Production Casing
- Cross-coupling Protectors, every other joint
- Fiber Optic Cable
- Tubing
- Tubing Tail can be extended below the bottom perforation
- Bottom Hole Gauge Carrier with PT Gauge

Casing (Permanent)
- Surface Casing
- Production Casing
- Cross-coupling Protectors, every other joint
- Fiber Optic Cable
- Tubing
- Bottom Hole Gauge Carrier with PT Gauge
Microseismic validation: DOE/GRI M-Site

- M-Site diagnostics laboratory: validation of microseismic data using tiltmeters and intersection wells
- Azimuth
  - Wellbores
- Height
  - Tiltmeters
- Length
  - Wellbores

Source: DOE/GRI M-Site test
Microseismic Validation in Gas Shales

Original Barnett microseismic monitoring

- Offset wells “killed” by fracture fluid
- Off distances of several hundred feet laterally from hydraulic fracture azimuth
- Tiltmeter results showing volume distributed in two primary azimuths
Downhole Microseismic Monitoring

Understand fracture behavior

- Planar
- Complex
- Height growth
- Fault interaction
- Azimuth
  - Sufficiently transverse
- Completion effectiveness
Microseismic Mapping Results: Marcellus

N45°E to N55°E, Xf = 600 to 1,000 ft
(most events <500 ft)

$h_r = 250 – 480$ ft; $w_{nf} = 370 - 920$ ft

Similar SRV’s ~ 350 $(10^6)$ ft$^3$

59% Out-of Zone

Well 2H (completed first)
Well 1H (completed next)
Eagle Ford Shale, DUG 2010 & SPE 138425

Microseismic and other monitoring

- Information on fracture behavior
  - Reservoir
  - Completion
  - Treatment

DUG Conference, 2010, Rosetta
Monitoring Of Completion Effectiveness

- Staging Tools
  - Mechanical Problems
  - Isolation Issues
- Perf & Plug
  - Staging Overlap
  - Fracturing Intensity
- Casing Problems
  - Horizontal Wells
    - Heel
Completion and Production Efficiency

- Eagle Ford Comparison Study
  - Frac valves
  - Plug & perf
- Diagnostics
  - Microseismic
  - Chemical oil tracers
  - Production
    - Separate stages
    - 2 wells

SPE 148642, 2011 CSUG/SPE
Magnum Hunter Resources Corp.
Stegent, Ferguson & Spencer
Completion and Production Efficiency:

- Stage Production Flow
- Chemical oil tracer stage results

Relative % of production flow

- Stages 1-11: Cemented Delta StimSleeve Frac Valves
- Stages 12-16: Plug-n-Perf

Austin Chalk

- Stg 10

Eagle Ford

- Stg 13

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Production Evaluation

- Comparison of two wells with different completions
  - Similar production

11 valves; 5 plug & perf
SRV from Surface Micro-deformation

- Dense array of tiltmeters over the horizontal well
- Measurement of surface deformation induced by the fracture
- Migrate deformation back into the subsurface
- Determine SRV and fracture components

![Observed surface uplift](image)
SRV from Surface Micro-deformation

- Measurement of both horizontal and vertical components
- Ignores fault activity
  - Very little volume injected into faults
- Similar SRV as microseismic on a stage-by-stage basis
- Applicable where no offset well is available
Example Integrated Microseismic / DTS Project
Measured Seismicity in the Eagle Ford Shale

- Microseismic monitoring records the “micro-earthquakes” that are induced by hydraulic fracturing.
- Amplitude of the microseism defines the moment and magnitude.
- Measurements from hundreds of fracture treatments provide clear information on levels of induced seismicity.
- Maximum < 1.0.
- Increase in magnitude with depth.
Microseismic mapping: an engineering and geologic tool

- Fracture optimization
- Fracture design
- Well layout and spacing
- Reservoir engineering
- Staging and completions
- Reservoir complexities
Summary

- Eagle Ford complexity requires integrated technical solutions
- Fracture mapping has aided development
  - Fracture complexity
  - SRV
  - Height growth
  - Fault interactions
  - Well spacings
  - Well trajectories
- Environmental benefits
  - Microseismic
    - Aquifers
    - Induced seismicity
Extra Slides
How Important Is Complexity and SRV in Shale-Oil Reservoirs?

Barnett single wells versus zipperfracs/simulfracs

- Network Spacing = 400 ft
- Network Spacing = 200 ft
- Network Spacing = 100 ft
- Network Spacing = 50 ft
- Network Spacing = 800 ft
- Zipper Frac/Simulfrac (per well average)

6-month cumulative gas (MMscf) versus Stimulated Reservoir Volume (10^6 ft^3)
Tilt SRA calculation

Use volume calculator approach

Divide reservoir into blocks

Invert surface tilt to obtain best-fit reservoir behavior

Block size lower limit: The difference in observed tilt between one block with fracture and two adjacent blocks having fractures of the same total volume should be greater than noise.
Example schematic of SRA results
Fracture Mapping Technologies

- **Microseismic**
  - Downhole Receiver Arrays
  - Detailed Mapping of Fracture Behavior
  - Requires Velocity Structure
- **Surface Microdeformation**
  - Surface Array of Shallow-Buried Tiltmeters
  - Provides Azimuth, Dip & Complexity
- **DTS**
  - Wellbore fiber monitoring

*Highest resolution & precision tiltmeters*

*Tiltmeters Placed in shallow (~10 m) boreholes*