Project Background

- New area/geologic province for Class 1 Wells
- No operator experience
- Limited regulatory experience
- No program guidance
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- 10,000 ft to 13,000 ft deep wells managing mine wastewater
  - 7” to 9 5/8” longstring casing
  - Casing seat/packer intervals 7,600-7,800’
  - Packers set under compression
  - Robust 4 ½” to 5 ½” tubulars
    - New tubing
    - Torque on joints to API specs
    - Pressure tested during installation
Project Background

- Typical low pressure seal pot design with nitrogen blanket
The Constraints

- Permit Conditions
  - Injection Pressures 1,750 - 2,200 psi
  - Annulus pressures 300-400 psi
- Annulus Pressures less than Injection pressures
  - Potential fluids migration wrong way to protect USDW
  - Relatively large differential pressures on tubing
The Conditions

- Large Temperature Differentials
  - Casing seat temps 120-130 degrees F
  - Injectate temps 35-55 degrees F
- Large Pressure Differentials
  - Injection tubing/annulus delta P > 1600 – 1800 psi
- Large Annular Volumes
  - 7,000-14,000 gallons
Three Operating Scenarios

- Injection under pressure & adding fluid
- Injection under pressure & removing fluid
- Post injection shut-in
Injection Under Pressure

Scenario 1

- Temperature of fluid in injection tubing is 70-90 degrees cooler than annular fluid

- Annular fluid contracts, pressure goes down

- Need to add fluid to seal pot due to volume change
Injection Under Pressure

Scenario 2

- Temperature of fluid in injection tubing is 70-90 degrees cooler than annular fluid
- Dynamic conditions on tubing create one way micro-leaks.
- Need to take fluid from seal pot due to volume change
Post Injection Shut in

- Temperature of fluid in injection tubing warms up over 70-90 degrees
- Annular fluid expands as its heated
- If seal pot isolated after shut in, annulus pressures climb to over 3,200 psi, while injection tubing is less than 100 psi
Defining The Solution

- Limited Set of Comparable Situations
- Inquiries Confirmed Results – But No “Magic Bullet”
  - Academia, Industry & Operators
Defining The Solution

- Limit Pressure Swings in Annulus
- Allow for Monitored Fluid Movement
- Real Time Measurement and Monitoring
The Fix

- Skid Mounted Annulus Monitoring and Control System
  - Small piston pump with VFD - meters flow in and out of annulus
  - Low volume flow meters and level sensors
  - Pressure relief valves
Injection Under Pressure

- Temperature of fluid in injection tubing is 70-90 degrees cooler than annular fluid
- PLC set points track annular pressure to stay 150 psi above injection pressure.
- No need to take fluid from seal pot due to volume change
Post Injection Shut in

- Temperature of fluid in injection tubing cools over 70-90 degrees
- Annular fluid contracts as its cooled
- AMS controls pressure decline to track tubing pressure
Positive Impacts on Operations

- No more fluid additions or removals
- Eliminated micro-leaks at tubing joints
- Annular pressure tracks injection tubing pressure in real time
- Reducing differential stresses on well components
Results of the Fix

- **New Permit Conditions**
  - Annulus Pressure 100-200 psi > Injection Pressure

- **No more micro leaks at tubing joints**
  - Strict control of annular fluid volumes

- **Well in continuous operation**
  - AMS cycles frequently on start-up then settles in to stasis once temperatures and pressures stabilize
  - Annular pressure tracks within 150 psi of injection tubing pressure
Conclusions

- 200 + tubing joints can experience significant stress under wide operational temperatures and pressures
- Micro leaks can be one way in nature
- High pressure wells require alternate annulus monitoring approach
- Solution relatively straightforward
- Saved client expensive workover/compliance issues
Discussion

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