Section 4
Dealing with Water Production During Waterfloods

- Water injection and production trends
- Reinjecting produced water versus make-up water
- Water quality needed to maintain injectivity
- Chemical tracers to identify channeling or premature water breakthrough
- Gelled polymers to modify permeability to increase sweep efficiency

Water Injection and Production Trends

- Get the water where the oil is!!
- Planning a waterflood
  - Determine water requirements as accurately as data permits
  - Survey all possible water sources (special attention to quantitative requirements)
  - Develop selected source as economically as possible
  - Largest daily demand occurs during fill-up (when no return water is available)
- Maintain high injection rate during fill-up
  - 1 to 2 B/D/acre-foot is desirable

Water Injection and Production Trends (cont.)

- After fill-up rule-of-thumb injection rate is about 1 B/D and not less than ½ B/D/acre-foot
- Pore volume (PV) method provides good estimate for ultimate water requirements
- Volume of water should range from 150 to 170% of total pore space
  - Include PV of any adjacent overlying gas interval or basal water zone
- Produced water will comprise 40 to 50% of the ultimate water requirements

Water Injection and Production Trends (cont.)

- If gas and water interval are present
  - Less return water will be available
  - Ultimate make-up water requirement will increase to as much as 60 to 70% of the total quantity of water injected
- Volume of produced water increases during flood
- As flood front reaches a producing well
  - Fluid volumes increase
  - Increase artificial lift equipment capacity
  - Important to capture as much oil as possible
  - Monitor fluid levels

Water Injection and Production Trends (cont.)

- As flood front reaches a producing well (cont.)
  - As flood advances past the producing well higher percentage of water will be produced
  - Maybe advantageous to shut-in or convert to injection to keep from robbing water from the front
  - Reactivate later and produce to economic WOR
- Run material balances between injectors and producers (compare water in versus water out)
- Similarities could indicate channeling or communication problem
  - Check by stopping or decreasing injection
  - If correlation exists, verify with tracer

Reinjecting Produced Water Versus Make-Up Water

- Must reinject produced water for economics, unless cost of treating is to high
- Check incompatibilities between waters and rock
- Pay special attention if precipitants form
- Can isolate waters in surface system and inject separately
- When mixing incompatible brines cannot be avoided
  - Mix on surface
  - Chemical treating, backwashing and acid treatments will increase

Water Quality Needed to Maintain Injectivity

- Balance between water quality and cost must be determined
- Cost elements include
  - Installation costs of water treating facilities
  - Chemical costs
  - Frequency and cost of well clean-up workovers
  - Other maintenance and operating costs
- Economic analysis must consider
  - Delayed production due to poor injectivity
  - Potential lost production due to reduced sweep

Water Quality Needed to Maintain Injectivity (cont.)

- Oil carryover causes formation damage in injection wells
- Maintain injection rates below parting pressure
- Poor water quality results in lost oil production
- 5 components in water detrimental to waterflood
  - Microorganisms
  - Dispersed oil
  - Suspended solids
  - Dissolved gases
  - Dissolved solids

Microorganisms

- Three classes found in water used in oil field
  - Algae
  - Fungi
  - Bacteria
- Bacteria most serious
  - Range in size from 0.2 to 10 microns
  - Controlled using biocide chemicals
  - Removed by filtration

Dispersed Oil

- Detrimental for 3 reasons
  - Bacteria utilizes certain components of crude as food
  - Oil is strongly absorbed iron sulfides and other scales, making it difficult to remove these with acid
  - Oil reduces relative permeability to water, requires more pressure to inject same amount of water
- Can be reduced by using demulsification chemicals and better design of water system

Suspended Solids

- Two types
  - Organic, from algae and bacteria
  - Inorganic, from minute particles of clay and sand or precipitates of calcium carbonate, iron sulfides, and other scales
- Many can be removed by settling tanks and filters
- Difficult and expensive to remove small particles less than 1 micron in size
- Rule-of-thumb is remove particulates larger than 1/3 the average pore throat diameter
- Average pore throat diameter in microns estimated by square root of formation permeability in md

Dissolved Gases

- Frequently found in injection waters
  - Oxygen
  - Hydrogen sulfide
  - Carbon dioxide
- All three enhance corrosion problems
- Oxygen can be removed using oxygen scavenger
- Gas blanketing water tanks minimizes oxygen
- Hydrogen sulfide can be oxidized to sulfur with oxygen or sulfur dioxide, or to sulfate with hypochlorite
- Carbon dioxide removed by stripping with inert gas (like nitrogen), cost generally exceeds benefit

Dissolved Solids

- Found in all waters
- Common materials in oil field waters
  - Cations (sodium, calcium, magnesium, barium, etc.)
  - Anions (carbonate, sulfate, chloride, iodide, etc.)
- Analyze water on a regular basis
- Implement chemical program to minimize problems

Using Chemical Tracers to Identify Channeling or Premature Water Breakthrough

- Used to determine water flow from injectors to producers
- Observing when and where it is produced provides information on
  - Directional flow trends
  - Identification of rapid interwell communication
  - Volumetric sweep
  - Delineation of flow barriers
- A tracer should have minimal interaction with formation or other fluids
- A water tracer is soluble in water, insoluble in oil, and does not absorb on the rock

Using Chemical Tracers to Identify Channeling or Premature Water Breakthrough (cont.)

- Injection water movement is monitored by analyzing produced water in area wells for the presence and concentration of tracer
- Important to monitor wells beyond immediate offset producers
- Can be injected as high concentration slug or continuously over longer time period
- Slug method requires frequent sampling to detect tracer spike as slug flows by
- Less frequent sampling for continuous method

Using Chemical Tracers to Identify Channeling or Premature Water Breakthrough (cont.)

- Inferences concerning channeling and areal sweep are drawn from tracer transit times and concentration levels
- Most successful if reservoir is "pressured up"
- Common tracers
  - Fluorescein sodium dyes
  - Ammonium nitrate or fertilizer
  - Ammonium thiocyanate
  - Lower molecular-weight alcohols

Using Chemical Tracers to Identify Channeling or Premature Water Breakthrough (cont.)

- Fluorescein sodium dyes
  - Generally used when severe channeling suspected
  - Can be visually detected at low concentration levels
  - Inexpensive
- Ammonium nitrate
  - Inexpensive
  - Field detection requires specific reagents and colorimetric equipment
- Ammonium thiocyanate is similar to ammonium nitrate, but costs more and not always available
- Lower molecular-weight alcohols are higher in cost and require lab analysis with gas chromatograph

Using Gelled Polymers to Modify Permeability to Increase Sweep Efficiency

- General information
- Candidate selection
- When to use polymer gel at the injector
- Treatment design
- Placing the treatment

General Information

- Many waterfloods plagued with low volumetric sweep efficiency due to
  - High permeability channels
  - Natural or induced fractures
  - Permeability contrasts between layers
- Injection-side treatments most common
- Two treatment methods
  - Crosslinking process
  - In-situ polymerization (monomers polymerized in the reservoir)

General Information (cont.)

- Permeability modification treatments must address
  - Correct identification of geological and reservoir characteristics
  - Correct design
  - Effective placement
  - Effectiveness lasting throughout project period
- Critical tasks
  - Identifying the channeling problem
  - Match appropriate technology to problem

General Information (cont.)

- Most failures caused by one or more of the following
  - Improper placement of gel polymer
  - Improper selection of candidate well
  - Lack of knowledge of wellbore integrity
  - Lack of adequate preparation of the wellbore prior to the job
  - Limited time allotted to implement treatment
  - Not understanding injection well profile prior to and after treatment
- With proper engineering, planning, and application success ratios of over 80% not uncommon

General Information (cont.)

- Facts operators should know about gelled polymers
  - Dry polymer mixed with water and crosslinked with metal ion
  - Gelation time controllable from hours to weeks
  - Slower gelation time allows more volume and deeper placement
  - Gels having viscosity and elasticity ranging from slightly greater than fresh water to rubber can be created in virtually any water, temperatures up to 400^{o}F, in high H_2S environments
  - Special equipment required to blend and pump

General Information (cont.)

- Facts operators should know (cont.)
  - Gels can be created to completely block flow or can preferentially reduce permeability
  - Gels created with wide range of polymer concentrations
  - Low concentration → less gel strength
  - High concentration → more gel strength
  - Weaker gels (colloidal dispersion gels) used in reservoirs dominated by matrix flow
  - Stronger gels (bulk gels) used in fracture or vug flow conditions
  - Equally applicable in sandstone or carbonates
  - Gels contain 98% or more water

Candidate Well Selection

- Selection criteria for injection well candidates
  - Significant remaining mobile oil-in-place that can be recovered with sweep improvement
  - Low secondary recovery due to poor sweep
  - Premature water breakthrough at producing wells
  - Evidence of direct channeling through fractures, vugs or high matrix permeability
  - High injection rates associated with low wellhead pressure

Candidate Well Selection (cont.)

- Factors determining waterflood efficiency
  - Reservoir heterogeneity
  - Mobility ratio
- Mobility defined as effective permeability of fluid divided by its viscosity
- In waterflood, mobility ratio is mobility of displacing phase (water) divided by mobility of displaced phase (oil)
- For mobility ratios greater than 1.0, polymer-augmented flooding should be investigated

Candidate Well Selection (cont.)

- Reservoir heterogeneity
  - Nonuniformities in reservoir properties
  - Generally more pronounced in vertical direction
  - Degree of heterogeneity determined from cores
  - Common descriptor is Dykstra-Parsons coefficient
  - Values range from 0 to 1

When to Use Polymer Gels in Injectors

- Use colloidal dispersion gel at inception of waterflood if Dykstra-Parsons coefficient is greater than 0.6 or if analogous flood suggests premature water breakthough will be a problem
- Inject bulk gel after waterflood inception if water channeling creates sweep problem
- Expected results
  - Increased resistance at injector
  - More oil produced faster at lower WOR
  - Less water to handle

Treatment Design

- Select process appropriate for reservoir/producing problem and treating/reservoir fluids
- Choices include
  - Near wellbore versus deep
  - Type of polymer and crosslinker
- Critical step is determining treatment volume
- Polymer solution should be injected until
  - Parting pressure is approached
  - Polymer is produced at peripheral producer
  - Maximum design size is acheived
- Interwell tracer data provides valuable information for designing size, gel time and gel strength

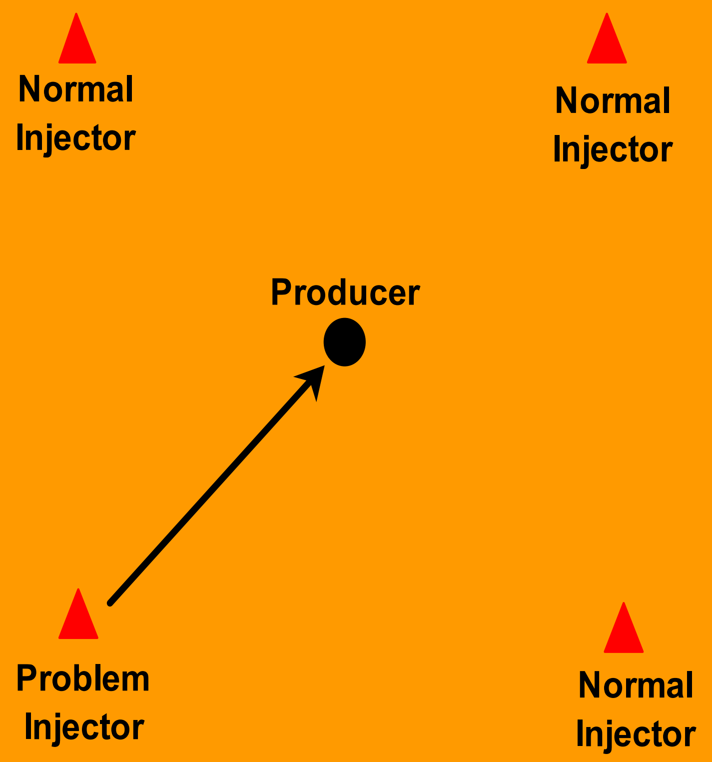
Performing the Treatment

- Clean candidate well
- Check chemical performance and compatibility onsite (trucks & frac tanks sources of contaminants)
- Mixing and injection procedures must ensure uniform polymer mixes
- Use design volumes and concentrations as guidelines
- Real-time Hall plot analysis use useful
- Increase polymer concentration in stages
- Inject at similar rate to normal injection
- Stay below parting pressure
- Keep offset producer active during treatment
- Over-displace with water

Red Fork Sandstone Formation - Oklahoma Co., OK
Background Information

- Problem Description: Water channeling through high permeability rock between one injector and one producer in a waterflood reservoir.
- Well Spacing: 40 acres
- Reservoir Depth: 7,750 ft.
- Net Reservoir Thickness: 50 ft.
- Reservoir Temperature: 150° F
- Average Porosity: 12%
- Permeability Range: 0.2-10 md
- Oil Gravity: 36° API

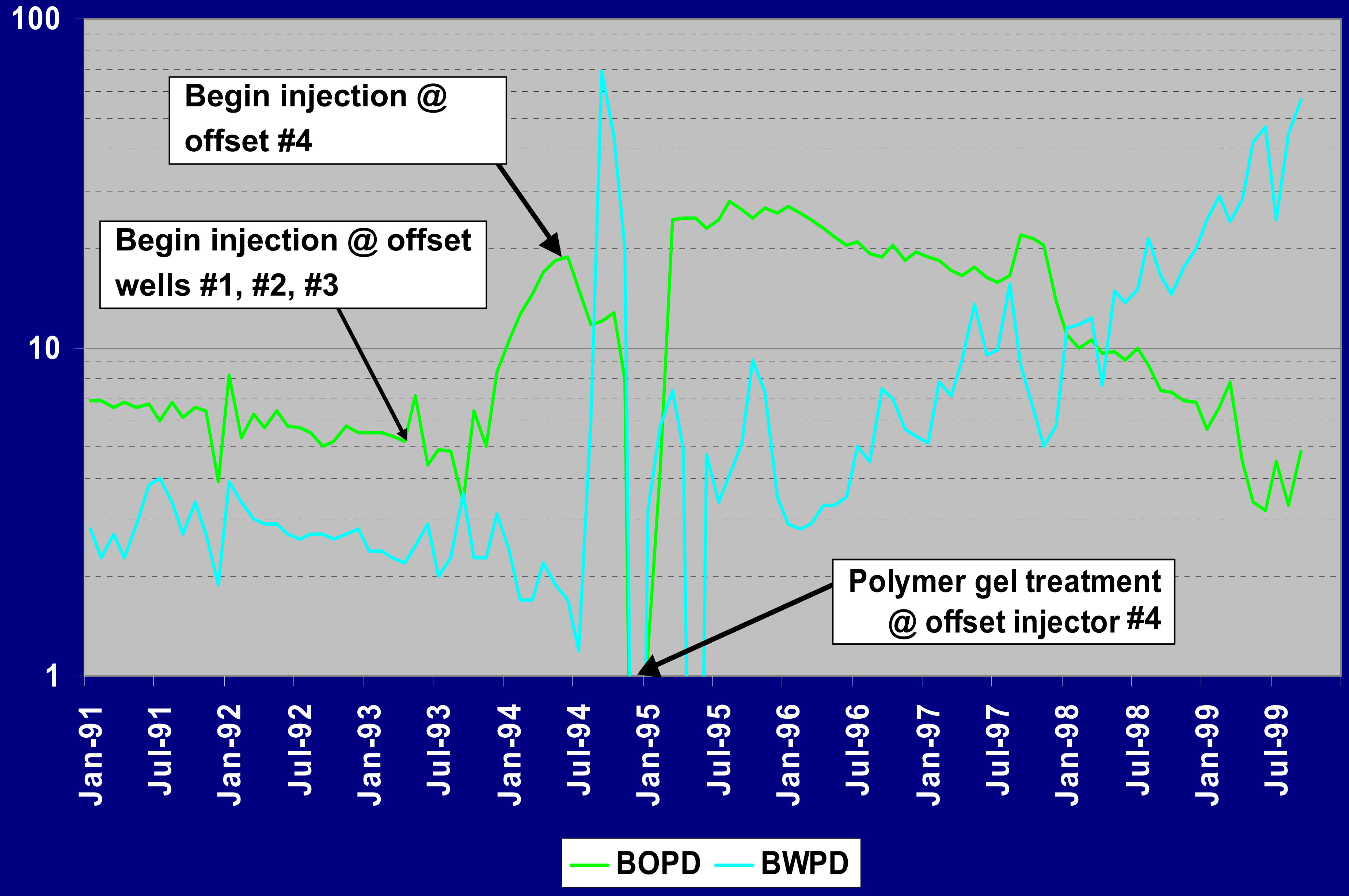
Red Fork Sandstone Formation - Oklahoma Co., OK
Project Area Map



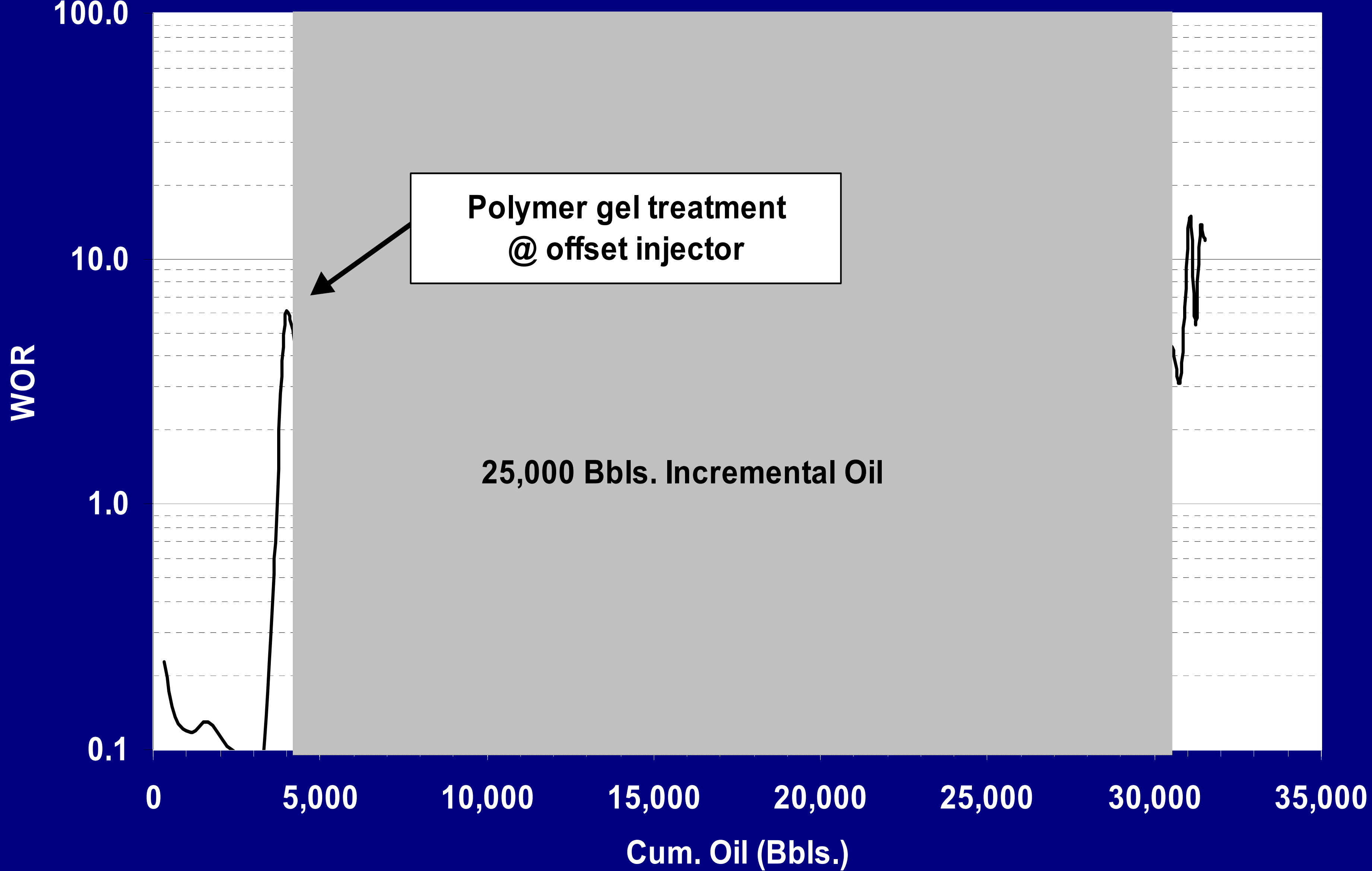
Red Fork Sandstone Formation - Oklahoma Co., OK
Treatment Design & Job Specifics

- 470 Bbls. gelled polymer
- 3,000 - 5,000 ppm polymer
- 100 Bbl. water overflush
- 2 days to inject (0.2 bpm treating rate)
- Beginning Pressure: 0 psi
- Ending Pressure: 1,390 psi

Red Fork Sandstone Formation - Oklahoma Co., OK



Red Fork Sandstone Formation - Oklahoma Co., OK



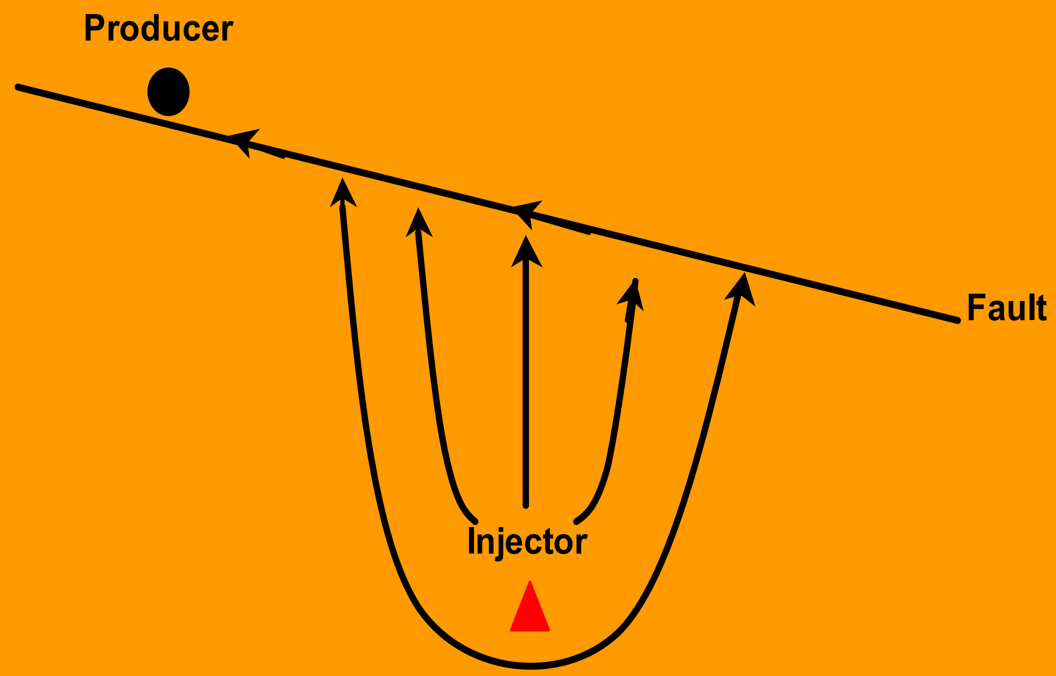
Red Fork Sandstone Formation - Garvin Co., OK
Treatment Economics

- Time to payout: 60 days
- Incremental oil to date: 25,000 Bbls.
- Job cost: $0.40 per incremental barrel of oil

Springer Sandstone Formation - Garvin Co., OK
Background Information

- Problem Description: Water channeling through high permeability rock between one injector and one producer in a waterflood reservoir.
- Well Spacing: 40 acres
- Reservoir Depth: 8,750 ft.
- Net Reservoir Thickness: 35 ft.
- Reservoir Temperature: 170° F
- Porosity Range: 8-28%
- Permeability Range: 1-1,000 md
- Oil Gravity: 40° API

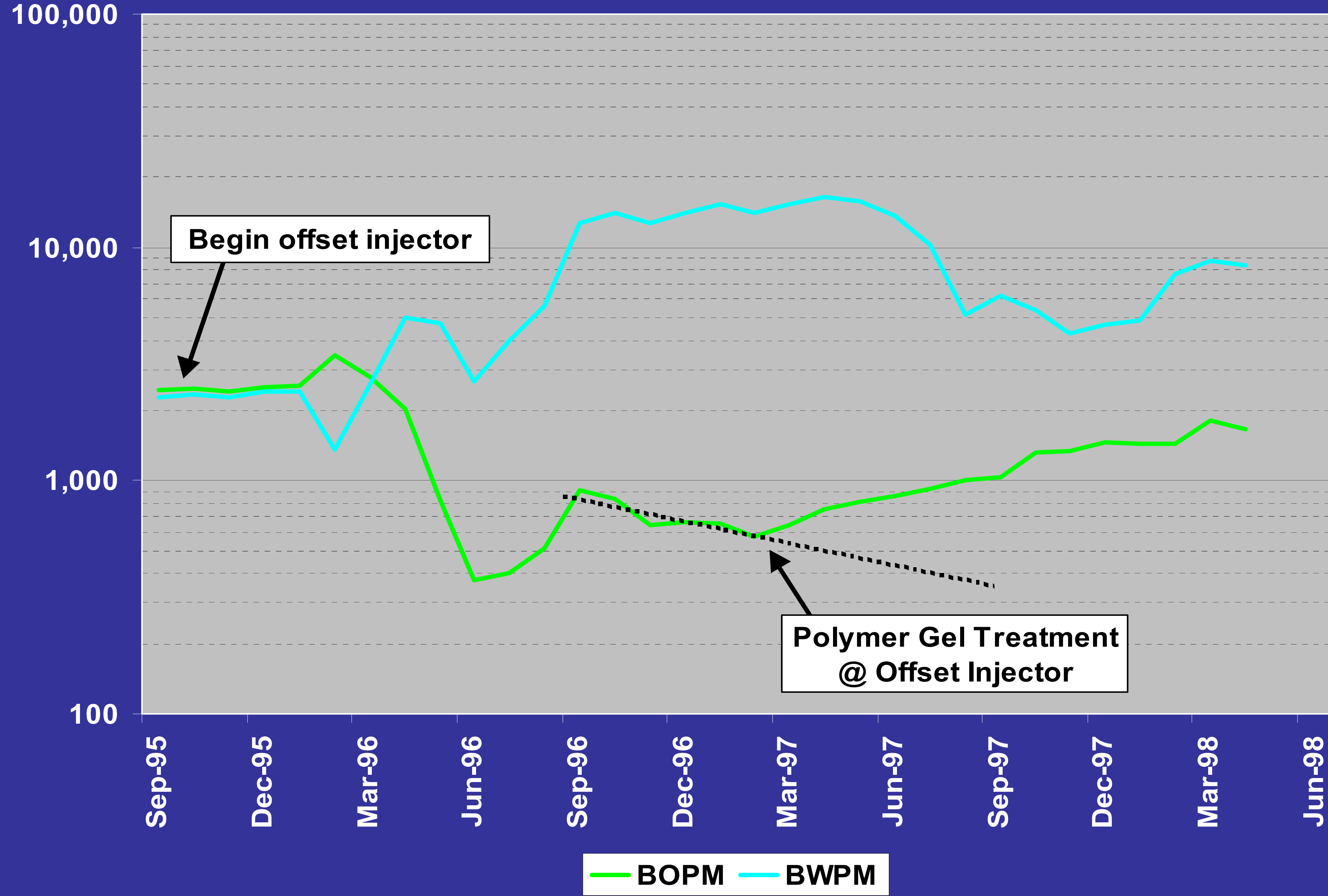
Springer Sandstone Formation - Garvin Co., OK
Project Area Map



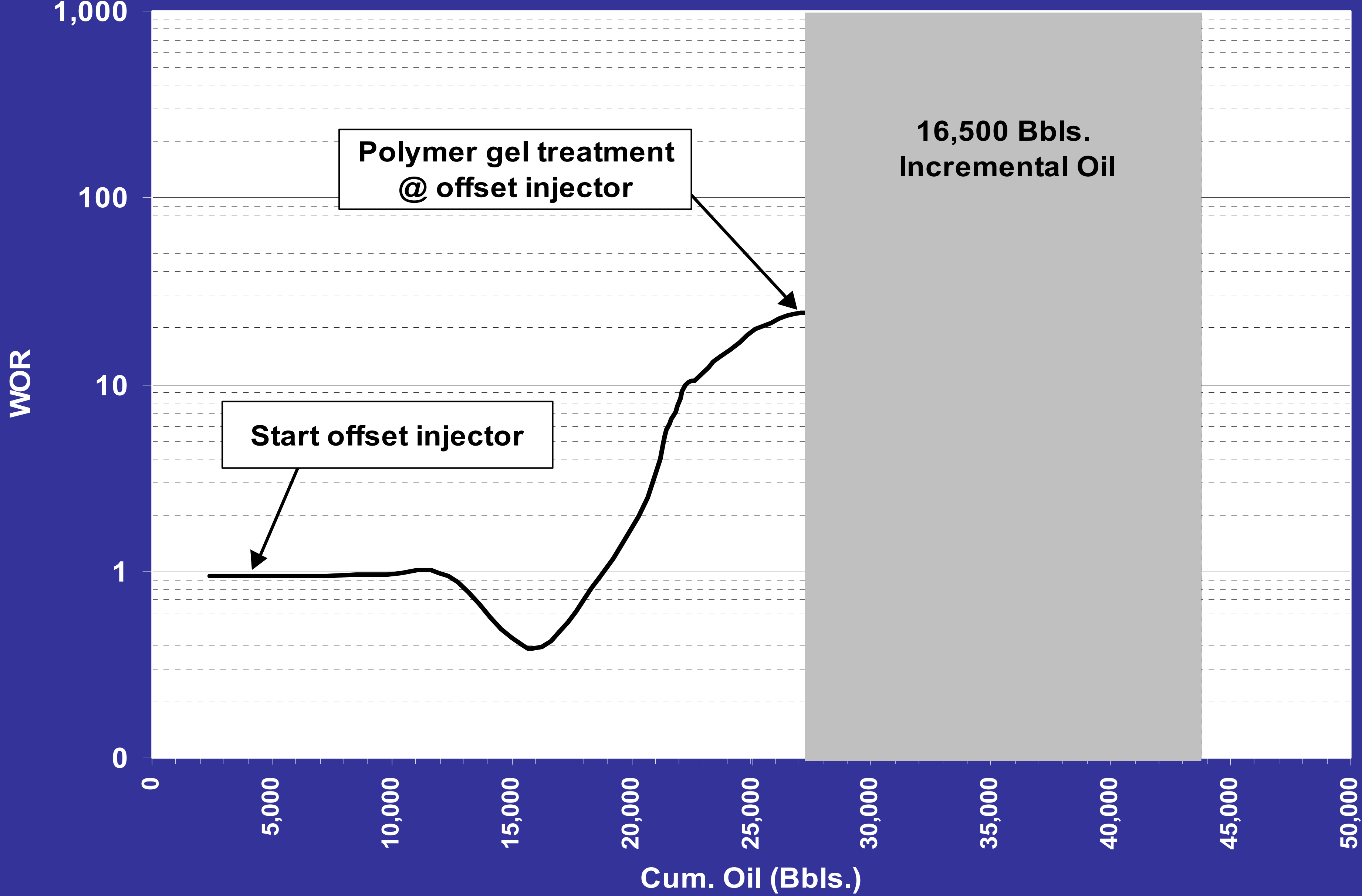
Springer Sandstone Formation - Garvin Co., OK
Treatment Design & Job Specifics

- 4,560 Bbls. gelled polymer
- 1,500 - 3,000 ppm polymer
- 75 Bbl. water overflush
- 6.5 days to inject (0.5 bpm treating rate)
- Beginning Pressure: 0 psi
- Ending Pressure: 2,100 psi

Springer Sandstone Formation - Garvin County, Oklahoma



Springer Sandstone Formation - Garvin County, Oklahoma



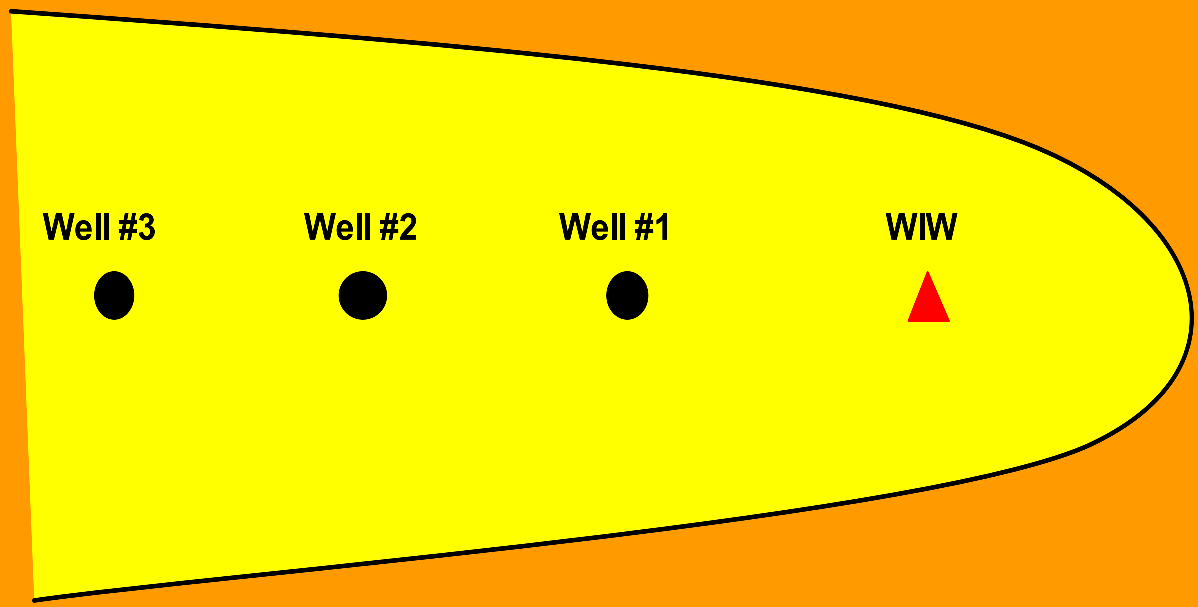
Springer Sandstone Formation - Garvin Co., OK
Treatment Economics

- Time to payout: 6 months
- Incremental oil to date: 16,500 Bbls.
- Job cost: $2.12 per incremental barrel of oil

Misener Sandstone Formation - Garfield Co., OK
Background Information

- **Problem Description: Premature water breakthrough at 2 producers**
- **Goal: Prevent breakthrough at 3rd producer by using gelled polymer at injector**
- **Well Spacing: 40 acres**
- **Reservoir Depth: 6,300 ft.**
- **Net Reservoir Thickness: 50 ft.**
- **Reservoir Temperature: 136° F**
- **Average Porosity: 10.4%**
- **Permeability Range: 0.5-13md (avg. 10 md)**
- **Oil Gravity: 42.5° API**

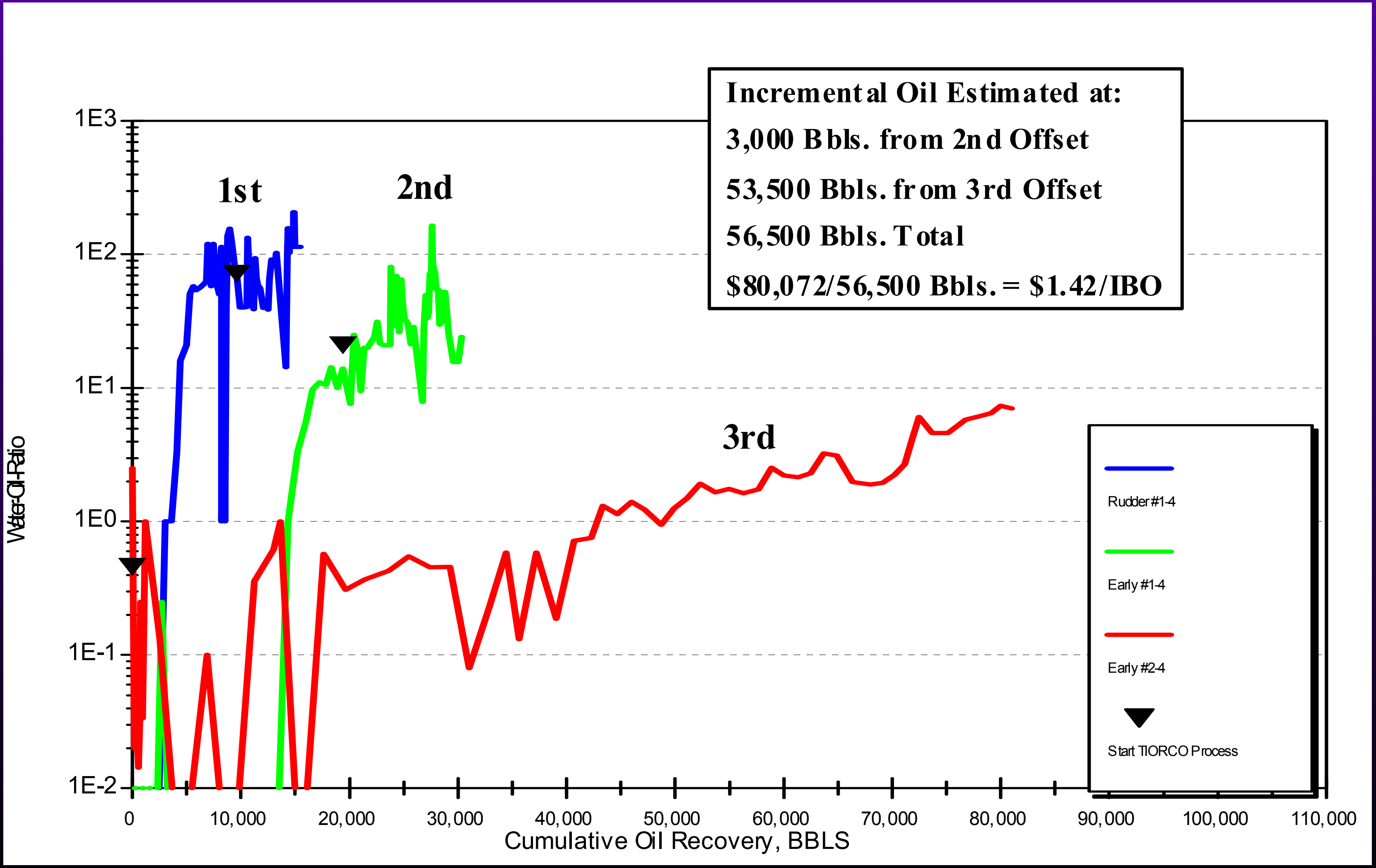
Misener Sandstone Formation - Garfield Co., OK
Project Area Map



Misener Sandstone Formation - Garfield Co., OK
Treatment Design & Job Specifics

- Treatment start date: March 1994
- 96,000 Bbls. gelled polymer
- 300 - 900 ppm polymer
- 5 months to inject

Misener Sand - Garfield Co., OK



Misener Sandstone Formation - Garfield Co., OK
Treatment Economics

- Time to payout: 12 months
- Incremental oil to date: 56,500 Bbls.
- Job cost: $1.42 per incremental barrel of oil