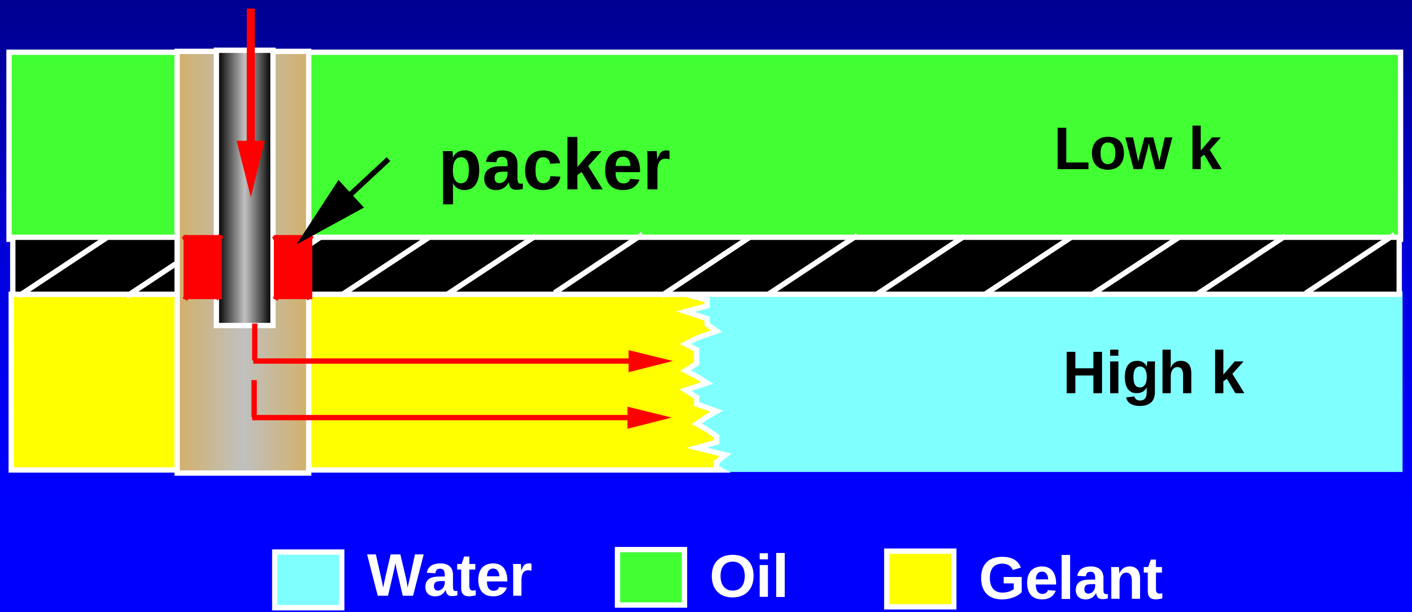
FIELD EXAMPLES

QUESTIONS FOR FIELD PROJECTS

- Why did you decide there was a problem?
- What did you do to diagnose the problem?
- What types of solutions did you consider?
- Why did you chose your solution over others?
- How did you size and place the treatment?
- Did it work? How do you know?
- What would you do different next time?

UNFRACTURED WELLS WITHOUT CROSSFLOW



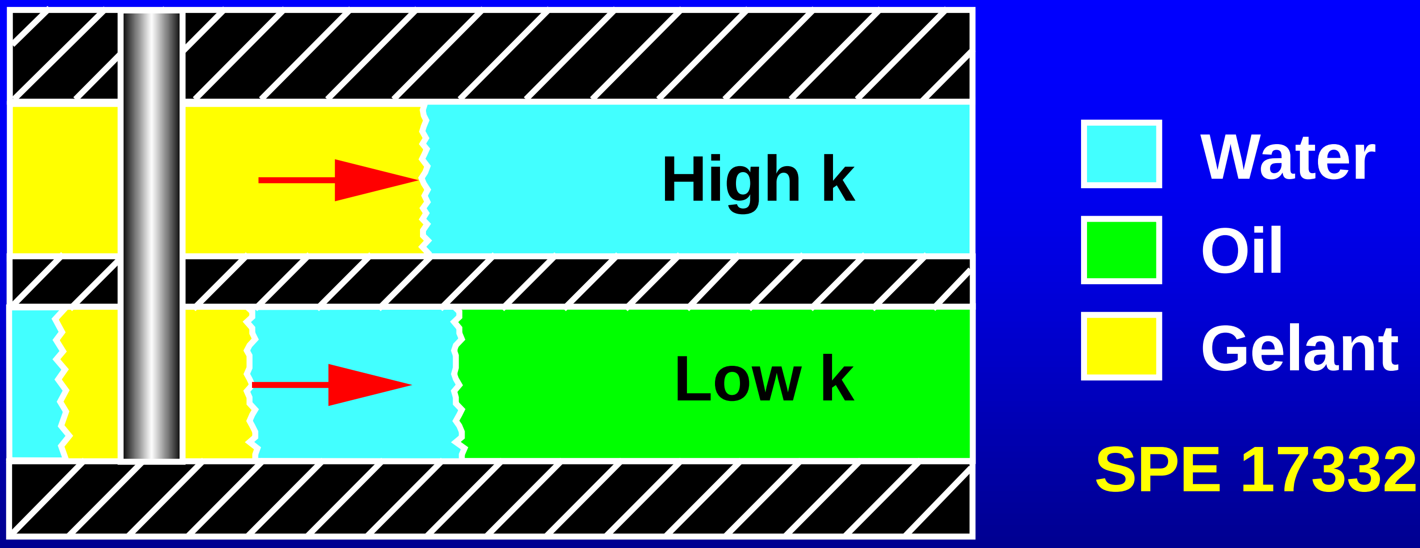
Possible Solutions

- Cement
- Sand plugs (if water zone is on the bottom)
- Mechanical devices (bridge plugs, packers)
- Gels
- Resins

Blocking Agent Placement

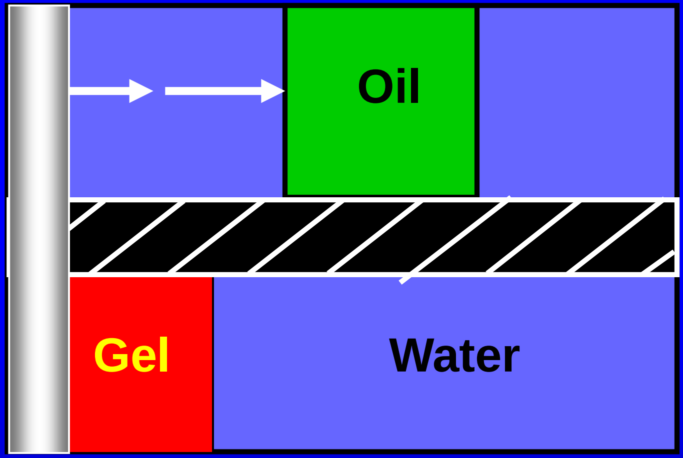
- In both injection wells and production wells, gelants and similar blocking agents can penetrate into all open zones.

- In radial flow (unfractured wells), oil-productive zones must be protected during gelant placement.

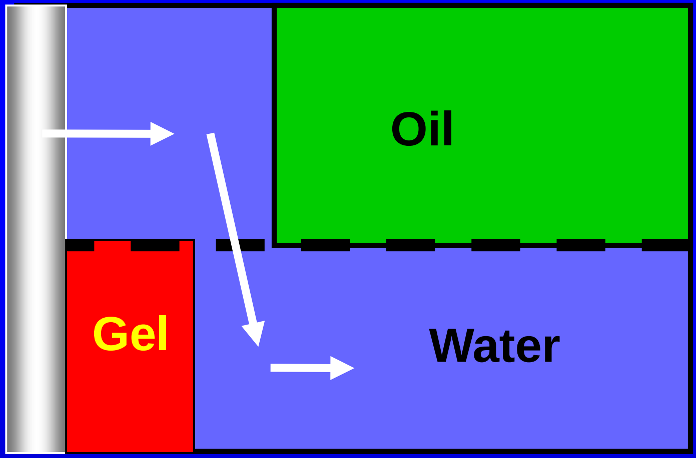


SPE 17332

**Without crossflow--
gel can be effective.**

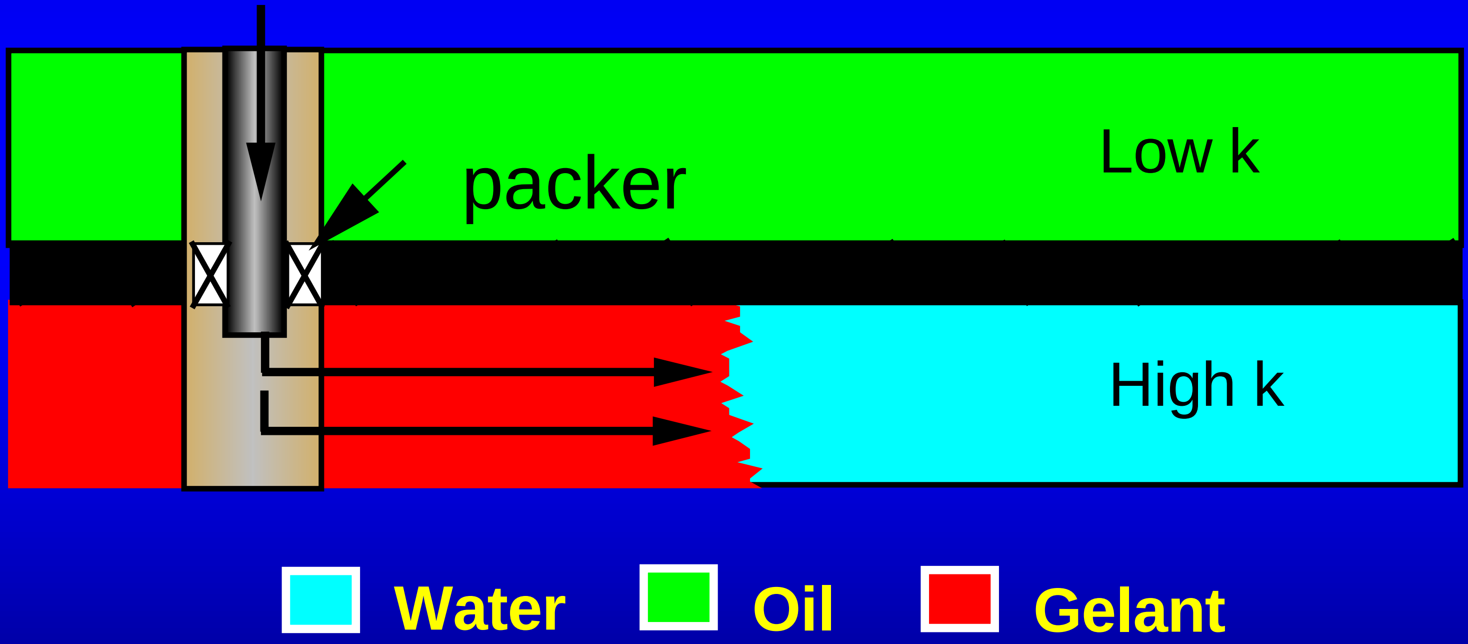


**With crossflow--
gel is ineffective.**

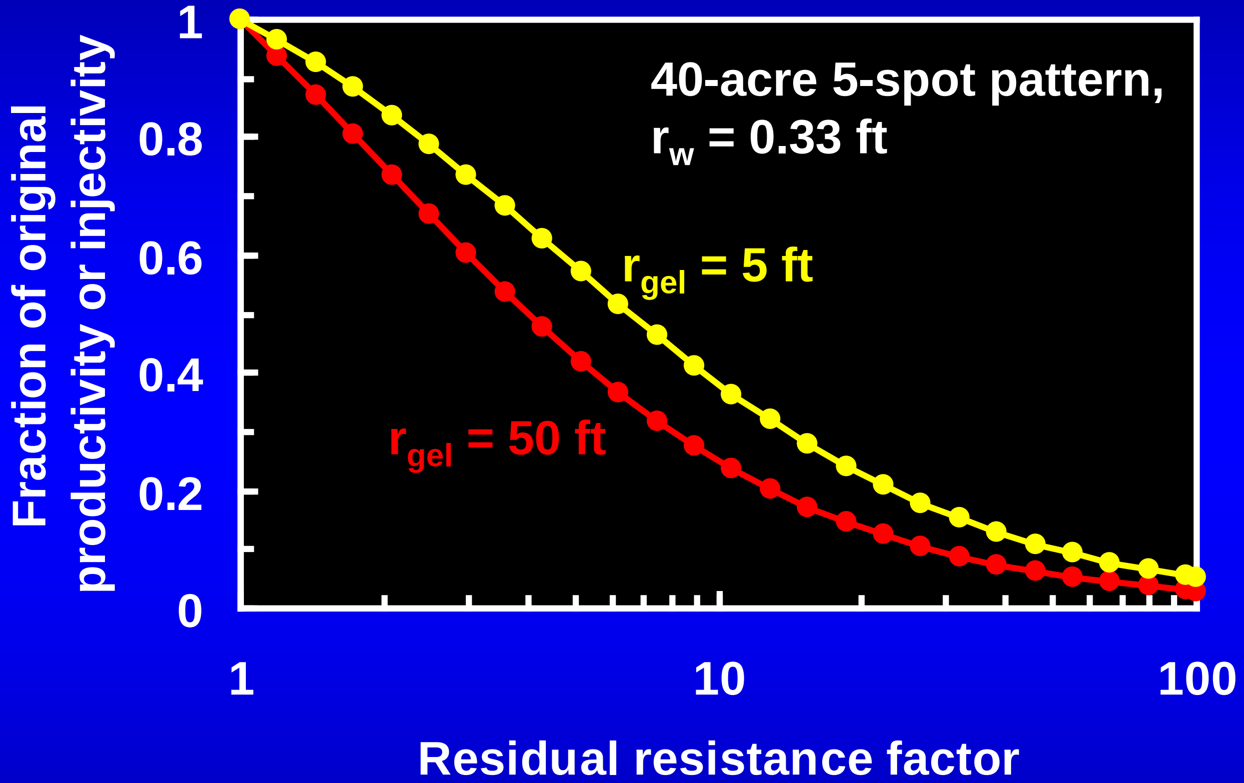


In-depth channeling problem, no vertical fractures, no vertical communication, zone isolation used:

- Inject enough gelant to get desired injectivity or productivity reduction in the water zone.



IN RADIAL FLOW, LOSSES ARE MORE SENSITIVE TO PERMEABILITY REDUCTION THAN TO RADIUS OF GELANT PENETRATION



This figure applies to both injection and production wells.

It also applies to both oil and water production.

SPE 24193
Shell Canada's Profile Control Gel Treatments in a Miscible IOR Project

- Virginia Hills Beaverhill Lake Unit, Alberta.
- Field discovered in 1957.
- Waterflood started in 1963 (36% OOIP ultimate).
- Miscible flood started in 1989 (8% OOIP IOR).
- 52 producers, 14 injectors, inverted 9-spot.

- Stratified Devonian reef reservoir.
- 5 separate zones spread over 250 ft.
- k varies from 5 to 1000 mD. ϕ varies from 5 to 15%.
- Reservoir pressure can vary from 2600 to 4000 psi within a given wellbore (depending on the zone).
- 80-acre spacing. 220°F (105°C), 4% TDS salinity.

SPE 24193: Shell's Gel Treatments: Choice of Treatment

Want to flood all zones simultaneously.

- **Mechanical methods were used in 9 of 14 injectors.**
- **Minimum spacing between packers must be 30 ft.**
- **Minimum spacing between perforations: 5 ft.**
- **In wells selected for gel treatments, 90% of fluid was entering 10% of the pay interval.**
- **Phenol-formaldehyde was stable at 220°F, 4% salinity.**

- **11% phenol-formaldehyde mixed in fresh water.**
- **1 cp gelant. Gelation time: 90 minutes at 220°F.**
- **Injection water temperature: 85°F (30°C).**
- **Injected solvent (gas) temperature: 40°F (4°C).**
- **Core tests indicated gel caused 20X k reduction.**
- **Gelant volume: 20 bbl/ft to reach 20-23 ft radius.**
- **Injection rate: 2 bbl/min. Pump time: ~ 2 hours.**
- **Zone isolation during gelant injection.**

SPE 24193, Shell Canada Injector Treatment

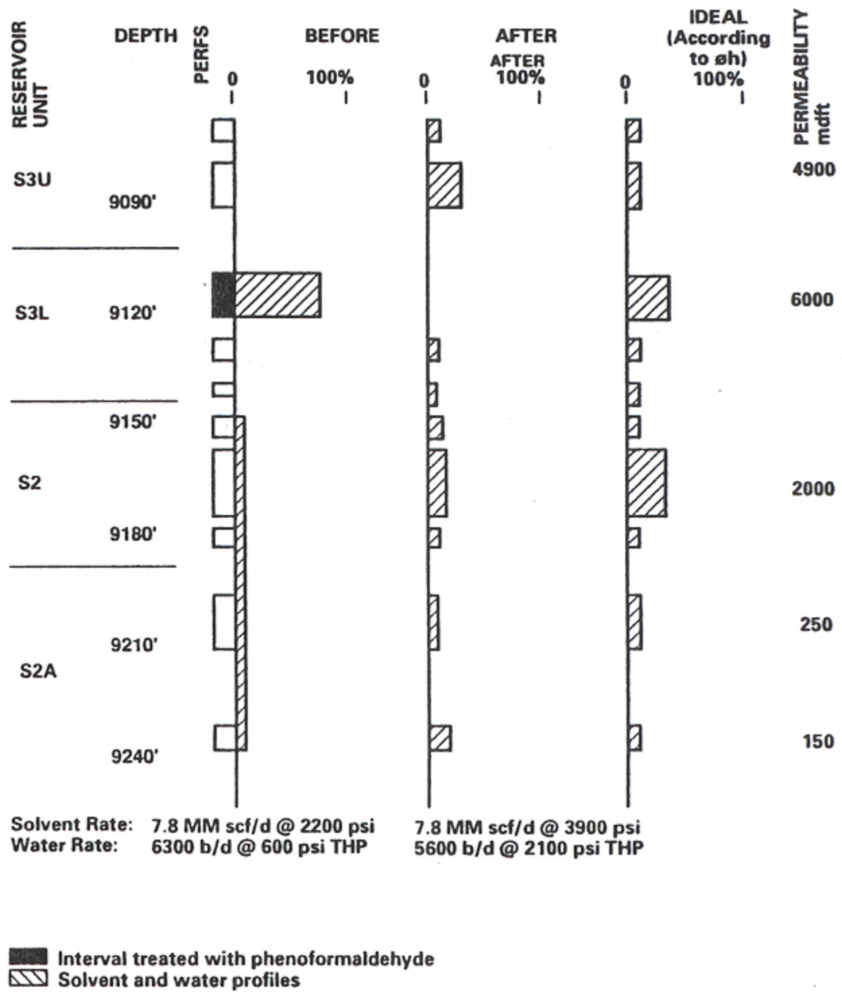


Figure 8
Phenoformaldehyde Treatment - Well 12-25 Miscible Injector

SPE 24193, Shell Canada Injector Treatment

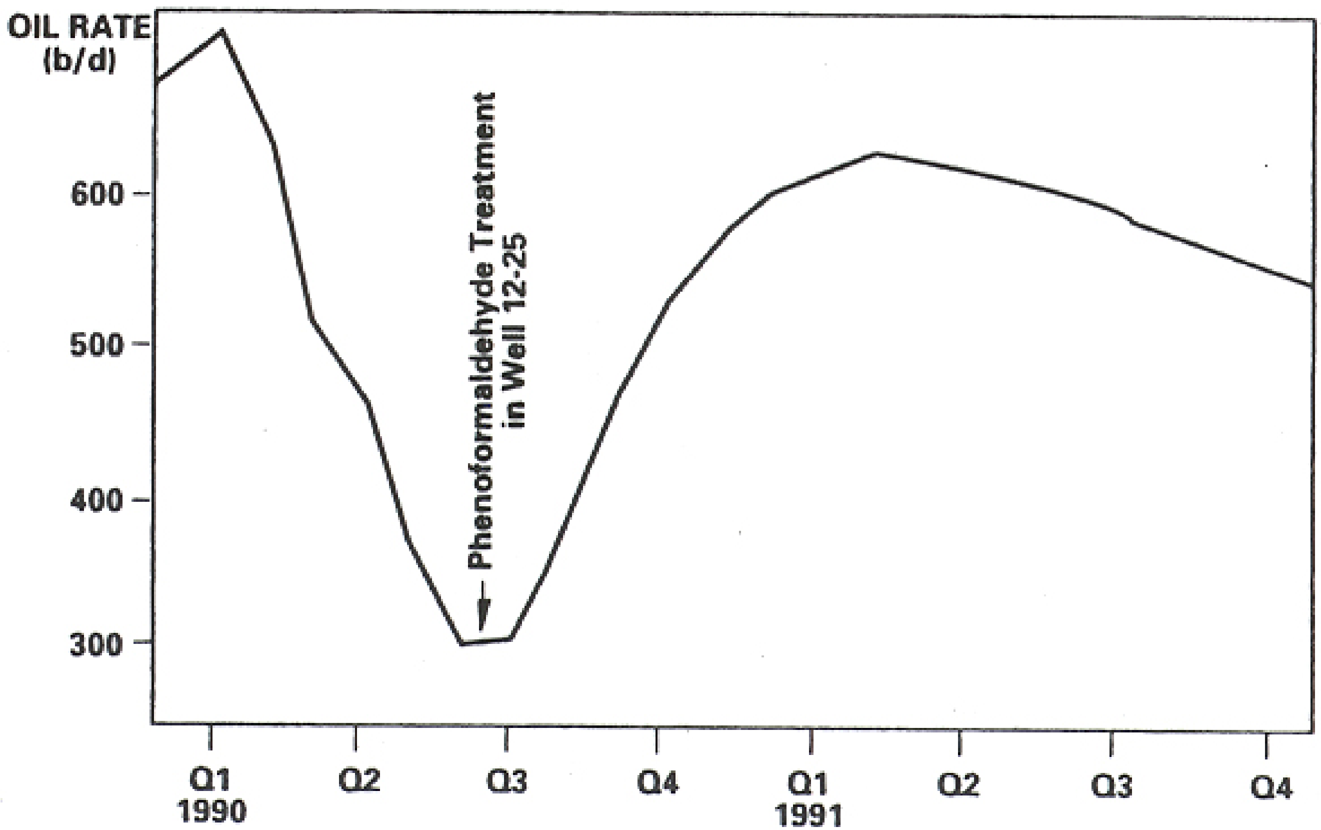


Figure 9

Monthly Oil Production from Pattern 12-25

SHELL CANADA: PROBLEM 1

Shell found that their phenol-formaldelhyde gel (that contained 11% active material) reduced permeability of a 500-md core by a factor of 20. Does this result suggest that a strong gel formed?

Expected Values:

$k_{gel\ inherent} = 125\ C^{-3} = 125\ (11)^{-3} = 0.094\ \mu D$

$F_{rrw} = k_{brine\ before\ gel} / k_{gel\ inherent} = 0.5/0.094 \times 10^{-6} = 5.3 \times 10^{6}$

versus 20 actual.

It looks like a very weak gel formed.

SHELL CANADA: PROBLEM 2

Shell found that their phenol-formaldelhyde gel, when placed to a 20 ft radius from injection Well 12-25, reduced the flow capacity of a 10-ft-thick thief zone (at 9120 ft) to an undetectable level. Assume r_e=1000 ft, r_w=0.5 ft, and static downhole pressure was 3950 psi. μ_w=0.25 cp. Before gel placement, the wellhead pressure was 600 psi with an injection rate of 5670 BWPD. After gel placement, the wellhead pressure was 2100 psi.

2A. What water flow rate into the thief zone would have been expected if F_{rrw} was really 20?

2B. If our limit of flow detection was 100 BPD, what was the minimum actual in situ F_{rrw}?

SHELL CANADA: PROBLEM 2A

r_p=20 ft, h=10 ft, depth=9120 ft, r_e=1000 ft, r_w=0.5 ft, p_r= 3950 psi, μ_w=0.25 cp. Before gel placement, the wellhead p=600 psi at 5670 BWPD. After gel placement, the wellhead p=2100 psi and flow was undetectable into the thief zone. What water flow rate into the thief zone would have been expected if F_{rrw} was really 20?

$q = \Delta p\ kh /[141.2\ \mu\ \ln(r_e/r_w)]$ $\quad$ $k = q\ 141.2\ \mu\ \ln(r_e/r_w)]/(\Delta p\ h)$

k=5670(141.2)0.25[ln(1000/0.5)]/[10(600+9120(0.433)-3950)]

k = 254 md

$q = \{\Delta p\ k\ h /[141.2\ \mu]\} / [F_{rr} \ln(r_p/r_w) + \ln(r_e/r_p)]$

q = [2100+9120(0.433)-3950]254(10)/[141.2(0.25) /
[20 ln(20/0.5) + ln(1000/20)]

q = 1945 BPD

SHELL CANADA: PROBLEM 2B

r_p=20 ft, h=10 ft, depth=9120 ft, r_e=1000 ft, r_w=0.5 ft, p_r= 3950 psi, μ_w=0.25 cp. Before gel placement, the wellhead p=600 psi at 5670 BWPD. After gel placement, the wellhead p=2100 psi and flow was undetectable into the thief zone. If our limit of flow detection was 100 BPD, what was the minimum actual in situ F_{rrw}?

$$q = \{\Delta p\ k\ h\ /[141.2\ \mu]\}\ /\ [F_{rr}\ \ln(r_p/r_w) + \ln(r_e/r_p)]$$

$$100 = [2100+9120(0.433)-3950]254(10)/[141.2(0.25)\ /\ [F_{rrw}\ \ln(20/0.5) + \ln(1000/20)]$$

Minimum in situ F_{rrw} = 409

So the gel formed much stronger in the field than in the laboratory.

SHELL CANADA: PROBLEM 3

Shell placed their phenol-formaldelhyde gel to a 20 ft radius in injection Well 4-20. In a 16-ft-thick thief zone (at 9165 ft), 3220 BWPD was injected at 1750 psi WHP. Assume r_e=1000 ft, r_w=0.5 ft, and static downhole pressure was 3968 psi. μ_w=0.25 cp. After gel placement, the injection rate was 275 BWPD at 1400 psi WHP. What was the in situ residual resistance factor (F_{rrw})?

$k = q\ 141.2\ \mu\ \ln(r_e/r_w)]/(\Delta p\ h)$

k=3220(141.2)0.25[ln(1000/0.5)]/[16(1750+9165(0.433)-3968)]

k = 31 md

$q = \{\Delta p\ k\ h /[141.2\ \mu]\} / [F_{rr} \ln(r_p/r_w) + \ln(r_e/r_p)]$

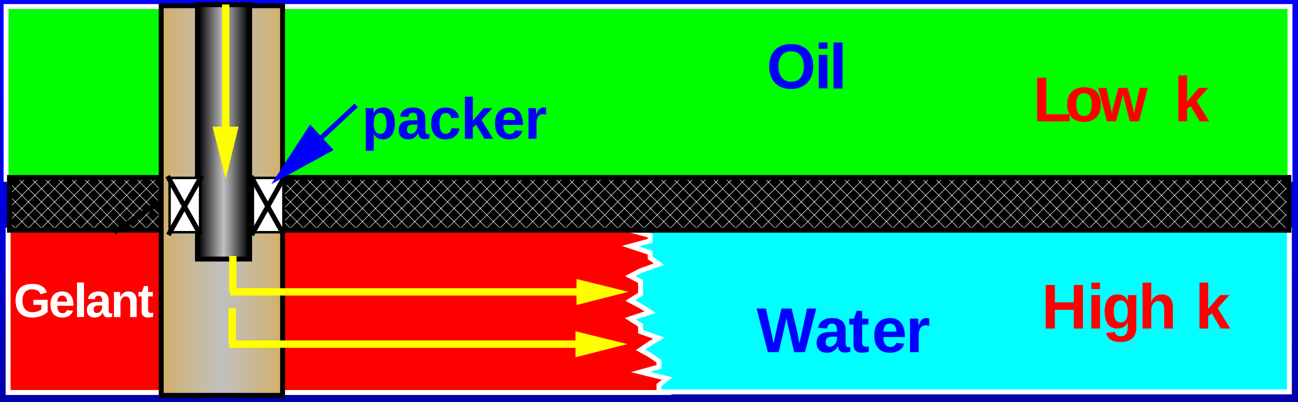
275 = [1400+9165(0.433)-3968]31(16)/[141.2(0.25) /

$[F_{rrw}$ ln(20/0.5) + ln(1000/20)]

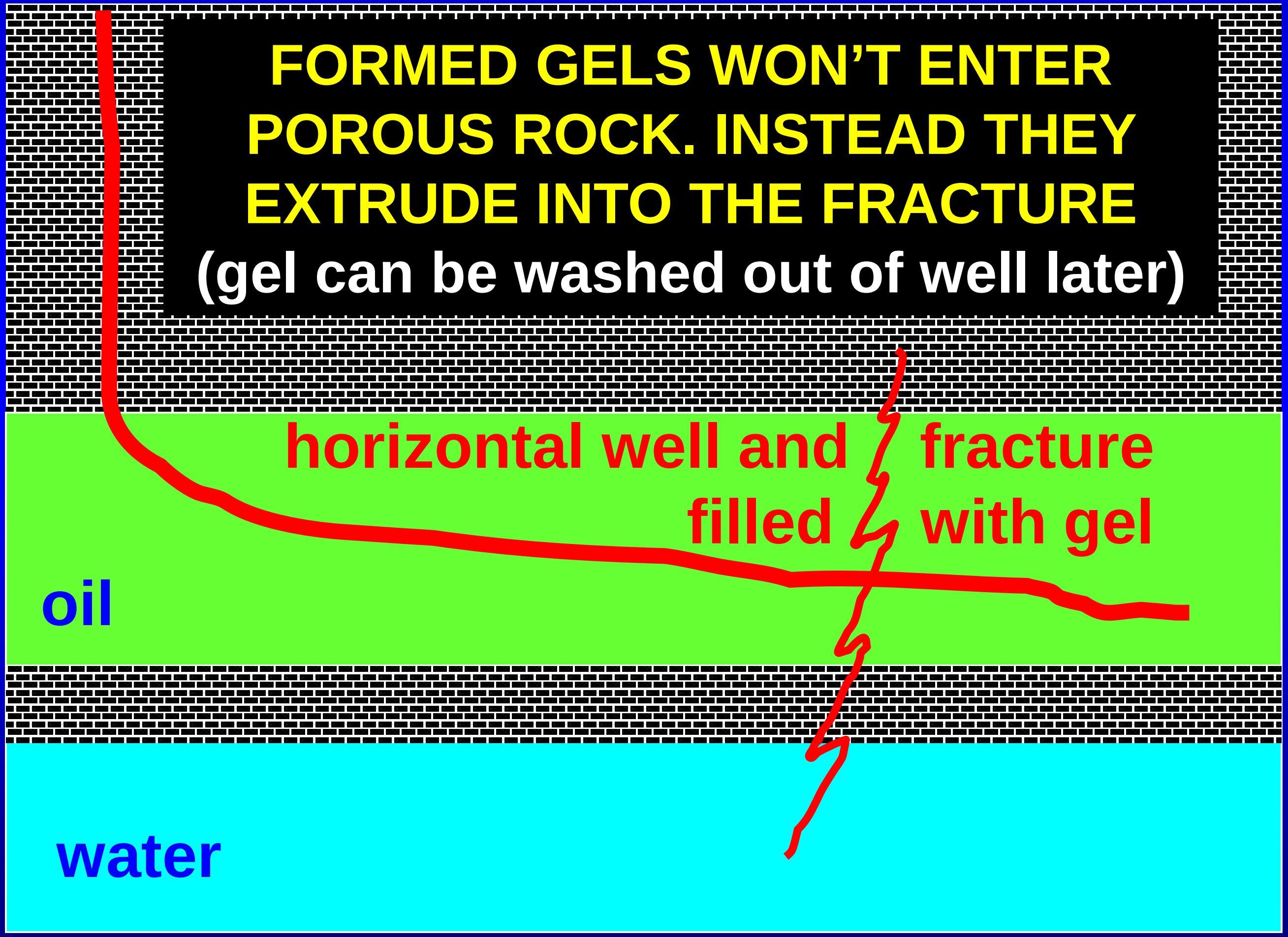
In situ F_{rrw} = 18, which is similar to the lab value of 20.

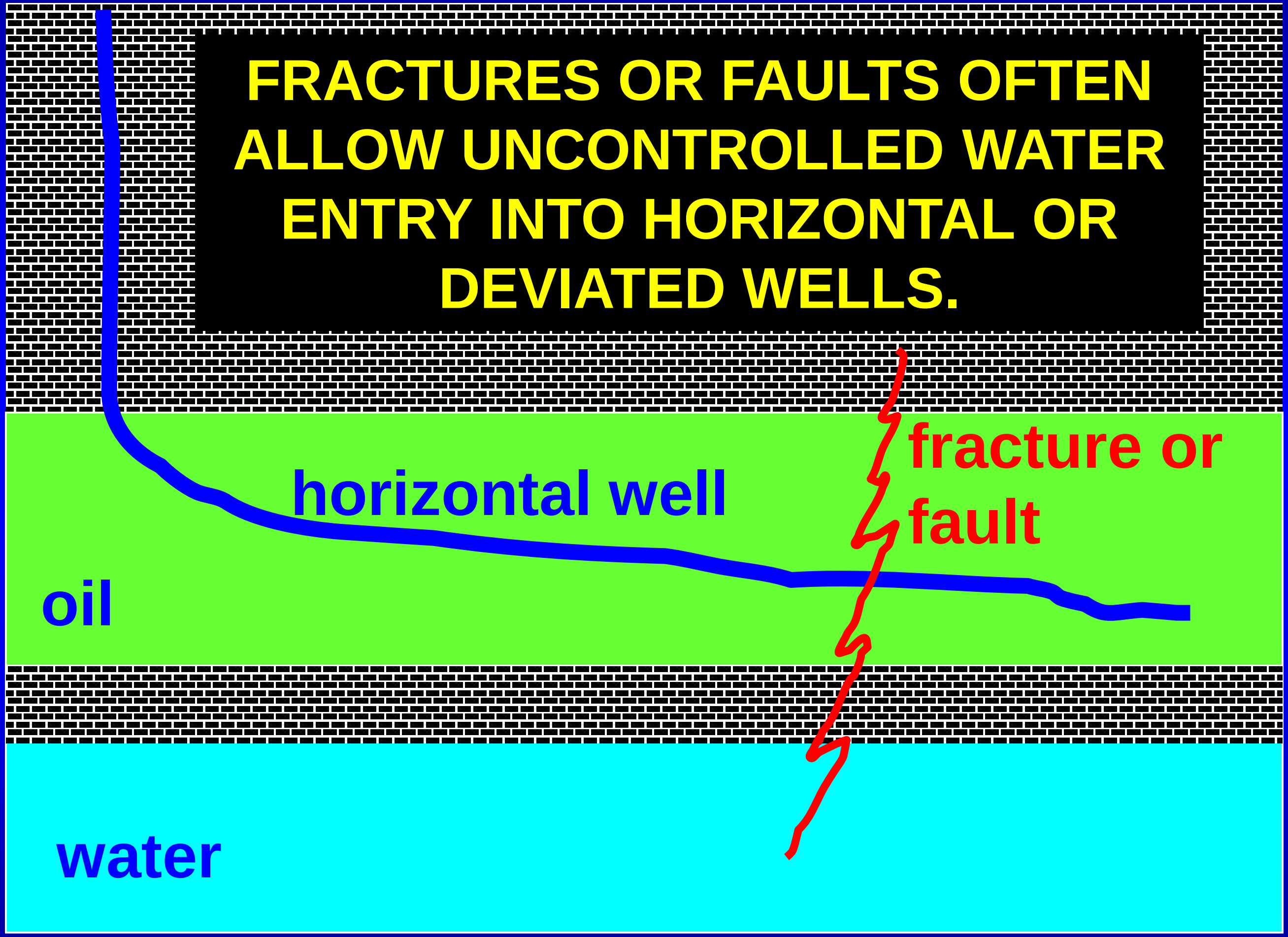
GEL TREATMENTS FOR RADIAL (MATRIX) FLOW PROBLEMS

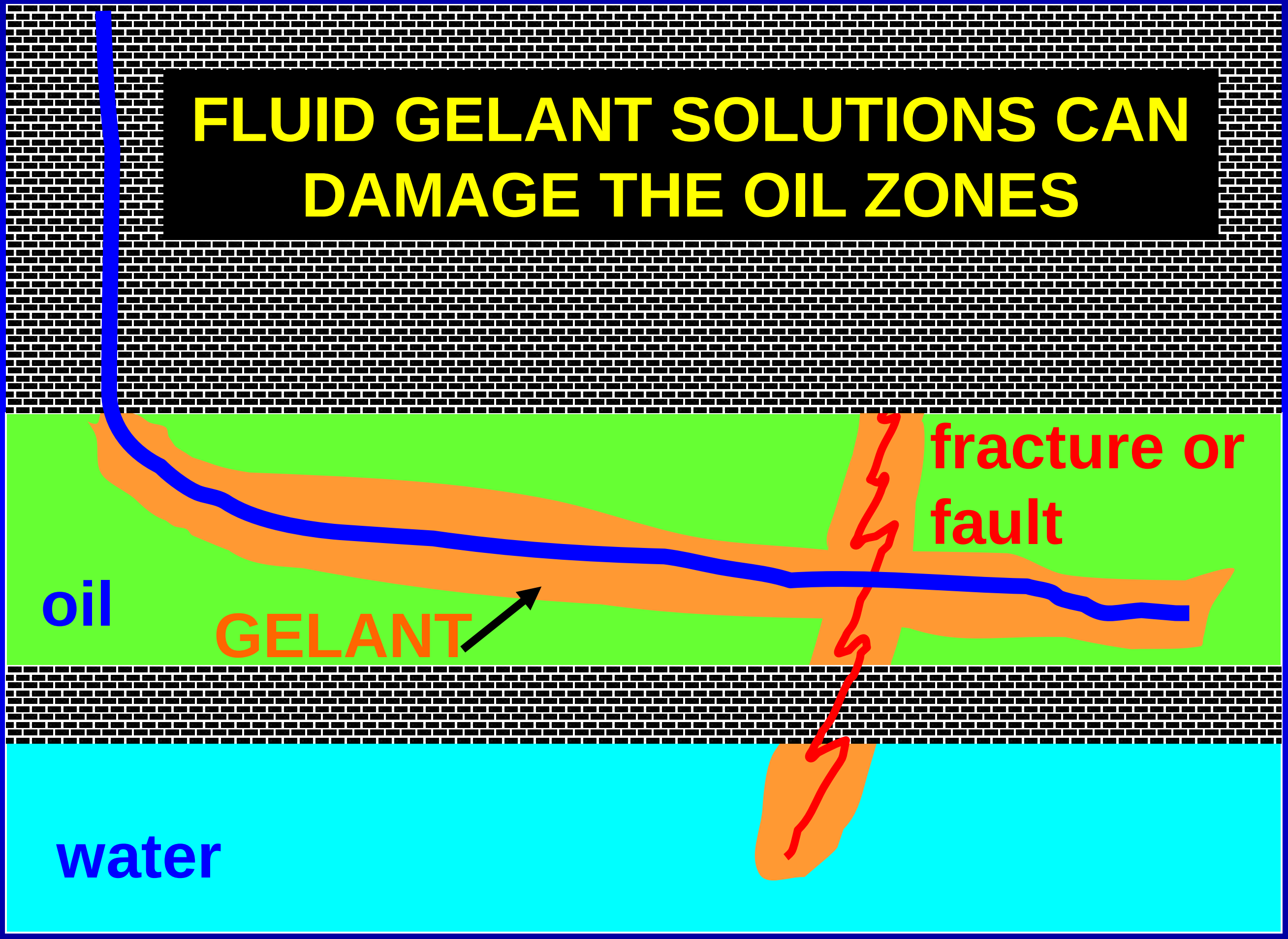
- Zones MUST be separated by impermeable barriers.
- Hydrocarbon-productive zones MUST be protected during gelant injection.
- Loss of water productivity or injectivity is not sensitive to radius of gelant penetration between 5 and 50 ft.
- Gel permeability reductions > 20 cause > 80% loss of water productivity.

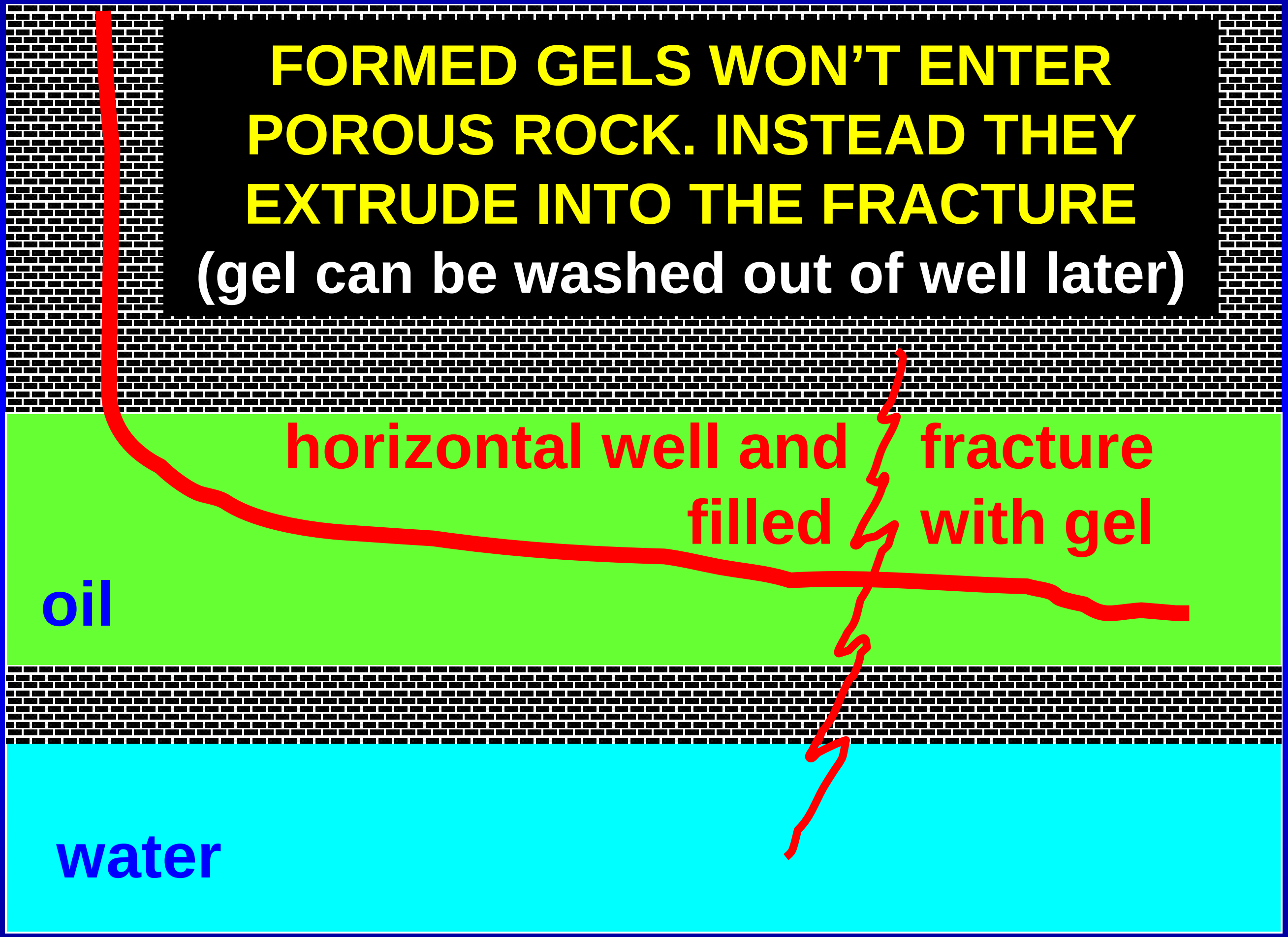


SPE 29475 & SPE 65527: **ARCO's (Bob Lane) use of Cr(III)-acetate-HPAM gels to plug a fault intersecting a horizontal well.**




FRACTURES OR FAULTS OFTEN ALLOW UNCONTROLLED WATER ENTRY INTO HORIZONTAL OR DEVIATED WELLS.
horizontal well
fracture or fault
oil
water


FLUID GELANT SOLUTIONS CAN
DAMAGE THE OIL ZONES
fracture or
fault
oil
GELANT
water


FORMED GELS WON'T ENTER
POROUS ROCK. INSTEAD THEY
EXTRUDE INTO THE FRACTURE
(gel can be washed out of well later)
horizontal well and fracture
filled with gel
oil
water

SPE 29475

ARCO's (Bob Lane) use of Cr(III)-acetate-HPAM gels to plug a fault intersecting a horizontal well

- Prudhoe Bay near-horizontal (85°) well.
- 11,853-ft length, 9009-ft true vertical depth.
- Initial production was 1,500 BOPD with 24% water cut. After 3 months: 400 BOPD with 90% water cut.
- Reservoir pressure ~3,200 psi.

SPE 29475: Problem Diagnosis

- Lost circulation noted during drilling at 11,327 ft.
- Gamma ray/neutron logs showed washed out shale at 11,335 ft.
- Cement bond log indicated poor cementing above 11,338 ft.
- Spinner log indicated most fluid coming from 11,327 to 11,345 ft.
- Temperature anomaly at 11,338 ft.
- Water analysis indicated all of it was formation water.

Conclusion: A fault-like conduit exists near 11,338 ft that connects to the underlying Sadlerochit aquifer.

SPE 29475: Treatment, Sizing, and Placement

- 12,000 bbl Cr(III)-acetate-HPAM gel. (Cement squeeze was expensive and unlikely to work.)
- Treatment sizing was subjective. (12,000 bbl was all they felt that they could afford.)
- Bullhead injection of gel.
- Pump time was 100 hours. Gel was extruded into the fault during placement.
- Well shut in for 5 days to allow gel to cure.

GEL INJECTION SEQUENCE

Polymer, wt %	Wellhead pressure, psi	Volume, bbls
0.3	400 – 0	22 (preflush)
0.3*	0 – 250	2,045
0.45*	225 – 525	5,500
0.6*	500 – 675	3,225
0.9*	725 – 800	740
0.3	800	100 (postflush)

2 BPM injection rate throughout.
*[HPAM]/[Cr(III) acetate] = 12/1.

TREATMENT RESULTS

Time	Oil rate, BOPD	Water rate, BWPD	Water cut, %	Oil PI, BOPD/psi	Water PI, BWPD/psi
11/93	466	4,290	90	0.32	2.95
Post-job	543	1,700	76	0.24	0.74
+ 1 mon.	727	1,895	72	0.30	0.78
+ 1 year	665	2,175	77		
+ 1.5 years	567	2,410	81		

CONNECTING LABORATORY & FIELD RESULTS (SPE 65527)

- Was the problem a fault or fracture?
- How wide was the fault or fracture?
- How far into the fault should the gel penetrate?
- Was the injected material a gel or gelant?
- How effectively did the gel seal the fault?

WAS THE PROBLEM A FAULT OR FRACTURE?

- Matrix or fracture flow?
- Fracture flow: $q/\Delta p >> k\ h\ /\ [141.2\ \mu\ \ln\ (r_e\ /\ r_w)]$.
- (4,290 BWPD + 466 BOPD)/[1,450 psi] = 3.3 BPD/psi.
- (100 mD x 0.1 x 18 ft)/[141.2 x 0.3 x 6] = 0.7 BPD/psi.
- 3.3 / 0.7 = 4.7.

Therefore, a fracture-like flow problems exists.

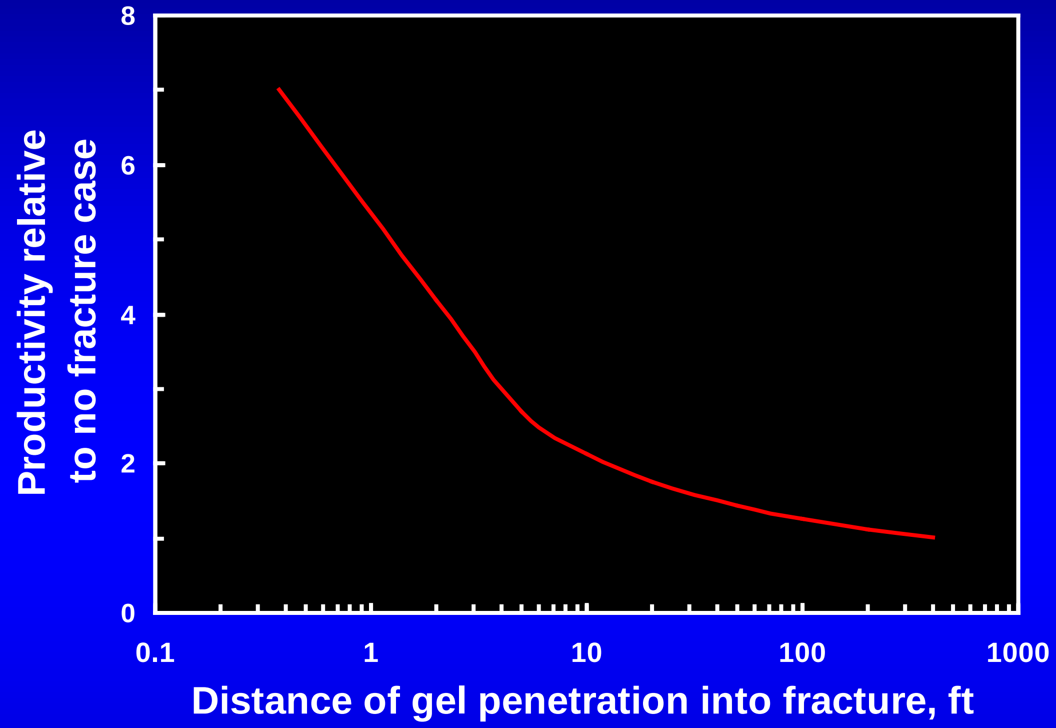
HOW WIDE WAS THE FAULT OR FRACTURE?

- Assume all water comes from fault.
- Radial flow into fracture:

  $q/\Delta p = k_f w_f / [141.2 \mu \ln (r_e / r_w)]$.
- Assume all water comes from fault: q = 4,290 BPD.

  Water PI = $q/\Delta p$ = 2.95 BWPD/psi.
- μ = 0.3 cp.
- $\ln (r_e / r_w) \sim 6$.
- $k_f w_f$ = 2.95 x 141.2 x 0.3 x 6 = 0.75 darcy-ft.
- $w_f = 12 \times 5.03 \times 10^{-4} \times (k_f w_f)^{1/3}$ = 0.0055 in. = 0.14 mm

HOW FAR SHOULD THE GEL PENETRATE?



- **For single fractures that cut horizontal wells, only moderate gel penetration is needed.**
- **Conclusion is not valid in vertical wells or if multiple fractures or a natural fracture system is present.**

WAS THE INJECTED MATERIAL A GEL OR GELANT?

- Injection rate: 2 BPM.
- Volume from wellhead to fault: 225 barrels.
- Transit time from wellhead to the fault: ~2 hours.
- Gelation time at 26°C: ~15 hours.
- Gelation time at 90°C: ~10 minutes.
- Total injection time: ~100 hours.

Injected material was gel during most, if not all of the gel placement process.

HOW EFFECTIVELY DID GEL SEAL THE FAULT?

BEFORE GEL:

- **Radial flow into fracture: $q/\Delta p = k_f w_f / [141.2 \mu \ln (r_e / r_w)]$.**
- **Water PI = $q/\Delta p$ = 2.95 BWPD/psi.**
- **μ = 0.3 cp, $\ln (r_e / r_w) \sim 6$.**
- **$k_f w_f$ = 2.95 x 141.2 x 0.3 x 6 = 0.75 darcy-ft.**

AFTER GEL:

- **Water PI = $q/\Delta p$ = 0.78 BWPD/psi.**
- **$k_f w_f$ = 0.78 x 141.2 x 0.3 x 6 = 0.198 darcy-ft.**

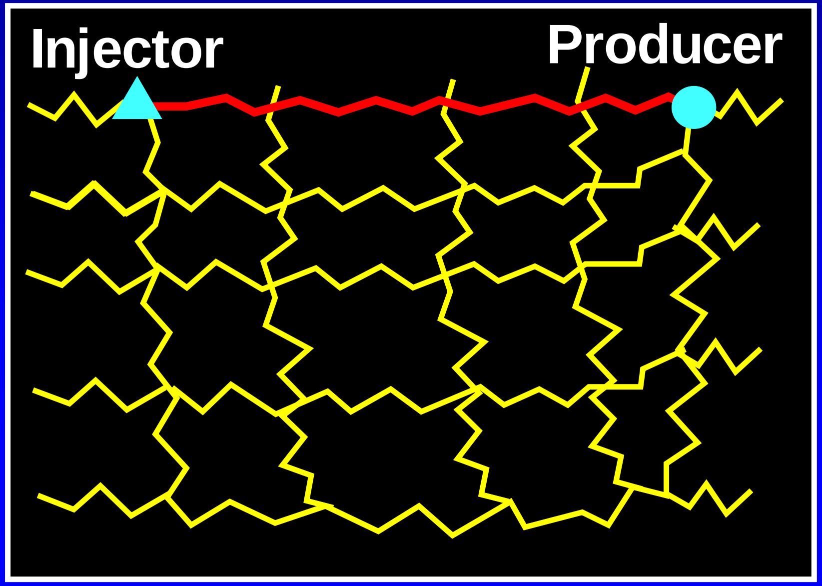
REDUCTION IN FRACTURE CONDUCTIVITY:

- **(0.75-0.198)/0.75 = 74% reduction.**
- **Implies fault is not completely sealed but calculation is conservative because it assumes all water came from the fault.**

- Simple calculations can give at least a rudimentary indication of the width of the fracture or fault that causes excess water production—which is relevant to the choice of gel.

- During field applications, accurate flowing and static downhole pressures should be made at least before and after the gel treatment is applied. Some very useful insights can also be gained if downhole pressures are measured during gel injection.

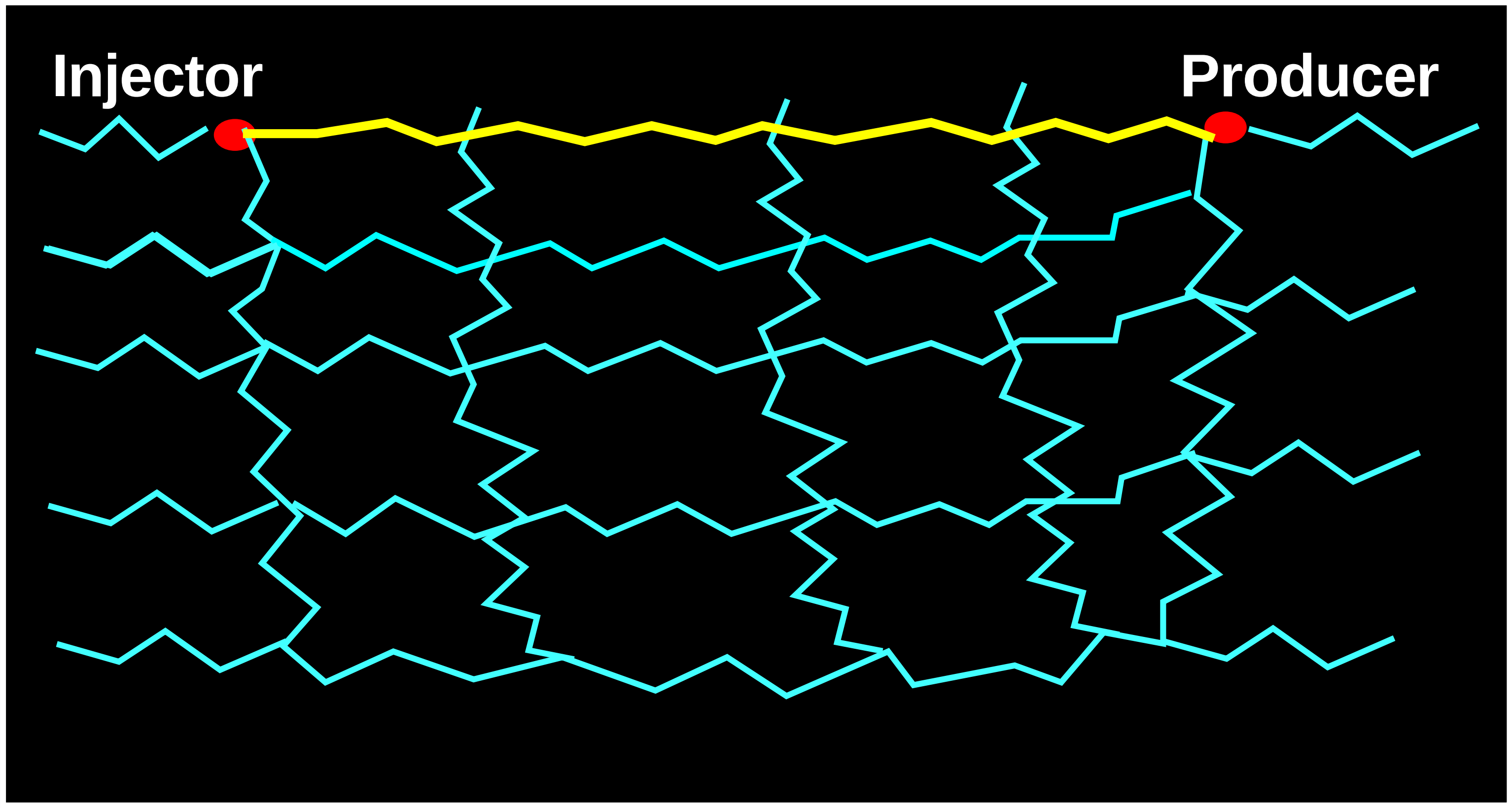
NATURALLY FRACTURED RESERVOIRS



- Want to restrict fluid channeling through the most direct fracture(s).
- Don't want to damage the secondary fractures (since they are important in allowing high well injectivities and productivities).

Naturally fractured reservoirs:

- Impressive well-documented cases,
- Greatest successes used large gel volumes,
- Optimum sizing unknown.



GEL EXTRUSION THROUGH FRACTURES

- Formed GELS injected instead of GELANT solutions.
- Gels extrude through fractures—no flow in porous rock.
- Successful field applications in treating:
  - Fractures or faults that cross horizontal wells.
  - Water or gas channeling through natural fractures.
- Gel dehydration and pressure gradients depend on w_f .
- Interwell tracers and injectivity/productivity data can indicate w_f for the most serious fracture(s).
- Gel sizing procedure is under development but:
  - Fastest injection yields the greatest gel penetration.
  - Slower injection increases gel’s staying power.
  - At a given rate, a 3X increase in gel volume yields a 2X increase in distance of gel penetration.
- More information: SPE 65527, *SPEPF* (Nov. 1999) 269-276, *SPEPF* (Nov. 2001) 225-231.

Cr(III)-acetate-HPAM Treatments to Reduce Channeling during WAG CO_2 Projects in Fractured Sandstone Reservoirs

	Wertz	Rangely
SPE paper	27825	56008
μ oil, cp	1.38	1.7
k, md	13	10
Lithology	sandstone	sandstone
Thickness, ft	240	175
T, °C	74	71
No. of treatments	8	44
HPAM, ppm	5000-8000	3000-8000
Treatment size, bbl	10,000-20,000	8,900-20,000
EOR/well, BOPD	100-300	21
EOR, total bbl	735,000	685,000
Total cost, $	963,000	2,060,500

SPE 39612: Chevron's Large Volume Gel Treatments in Injection Wells During a CO_2 Flood in a Naturally Fractured Reservoir

- Rangely field. Weber eolian sandstone.
- 675 ft gross thickness, 175 ft net pay.
- 6 distinct sand units
- ϕ=11%, k=10 mD.
- 376 producers, 278 injectors
- Discovered: 1933. First produced: 1944. Perpherial waterflood since 1958. Pattern waterflood since 1969.
- CO_2 flood since 1986.

SPE 39612: Chevron’s Rangely Field

Problem Diagnosis

- Extreme variability in CO_2 performance from pattern to pattern.
- Several patterns with rapid breakthrough.
- Pattern reports showed “under and over processed” zones.
- Chevron created a sophisticated rating system to quantify the merit for treatment.

SPE 39612: Chevron's Rangely Field

Did Fractures Cause the Problem?

- Injectivity was 23X greater than expected from Darcy's Law for radial flow.
- CO_2 breakthrough noted at 24 hrs with 1,300' well spacing--55 ft/hr propagation rate.
- Average effective permeability = 10 md, yet they routinely placed 10,000 bbls of polymer gel into formation.
- Linear flow character seen in injection well fall-off test data.

Chevron's Rangely Field—
Conformance Methods Applied

- Selective injection equipment (SPE 21649).
- Water-alternating-gas (SPE 27755).
- Recompletion (SPE 27756).
- Pattern realignment (SPE 27756).
- Gelled foams (SPE 39649).
- Gels (SPE 39612).

SPE 39612: Chevron's Gel Treatments

Treatment Design

- Water injected for ~1 week before treatment.
- Cr(III)-acetate-HPAM gel.
- 10,000-20,000 bbl injected per treatment.
- Typical injection time: 8-10 days.
- 0.5% HPAM in gel mostly, but ramped up to 0.85% HPAM at end.
- Flushed with 3 tubing volumes of water at end.
- Shut well in for 1 week.
- Inject water first on return to injection.

SPE 39612: Chevron's Gel Treatments

Range of Responses (44 Treatments Total)

- No response.
- Smoothing of production.
- Reduction in water.
- Reduction in gas.
- Areal sweep improvement.
- Oil rate increase.
- Reduction or elimination of oil decline.
- Better pattern CO_2 retention & utilization.

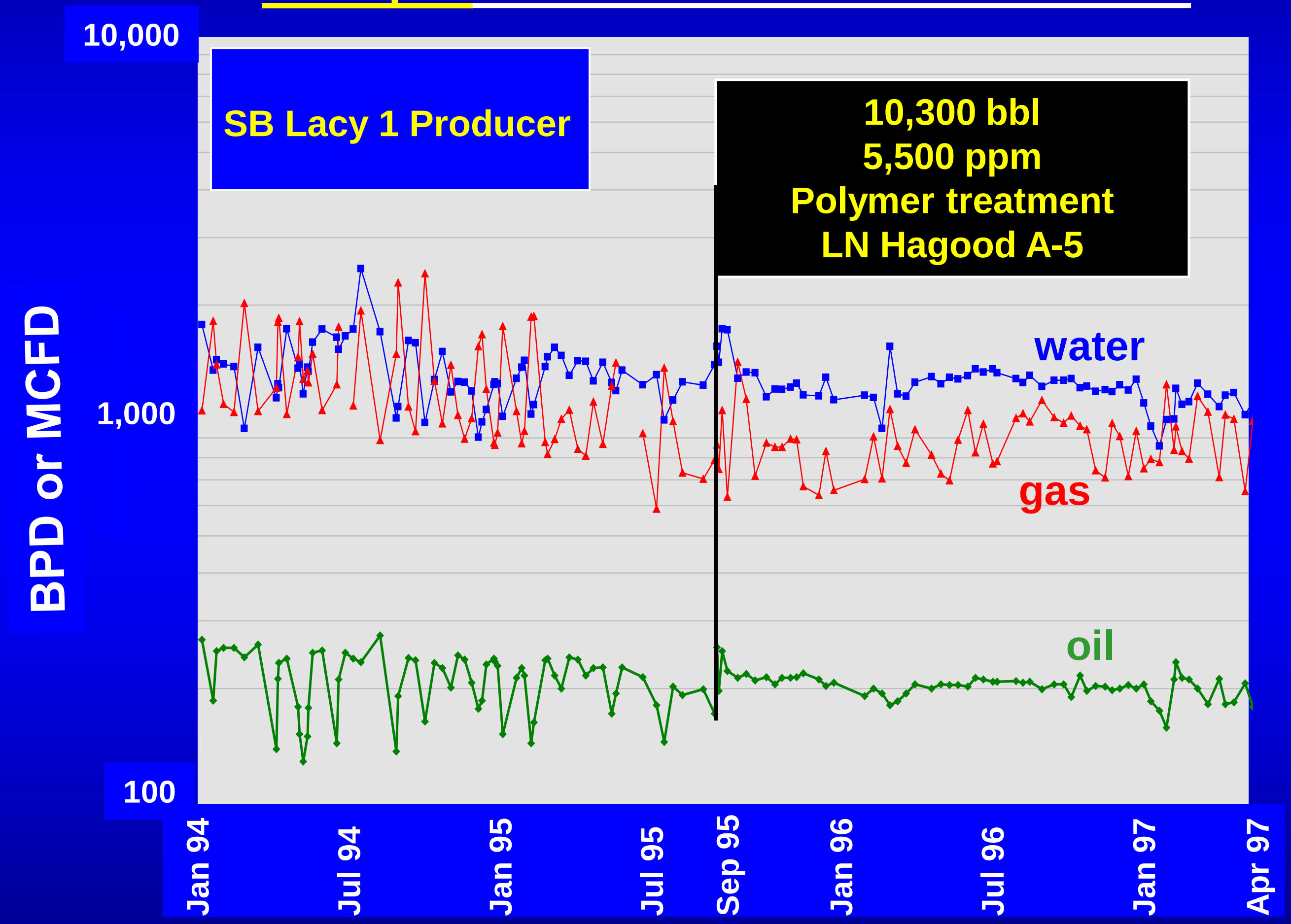
SPE 39612: Chevron's Gel Treatments

Example: Treatment Smooths Production

- Rapid breakthrough from injector to producer.
- No other producers supported.
- Thief appeared confined to one zone.
- Previous attempts at near-wellbore control were unsuccessful.
    - Liner, selective perforations.
    - Small-volume Cr(III)-acetate-HPAM treatments.

SPE 39612: Chevron's Gel Treatments

Example: Treatment Smooths Production



SPE 39612: Chevron's Gel Treatments
Results: 1994-1996

- Investment = $2,060,500.
- ROR: 365%. Payout: 8 Months.
- IOR: 685,000 BO.
- Success Rate: 80%.
- Average change per treated well:

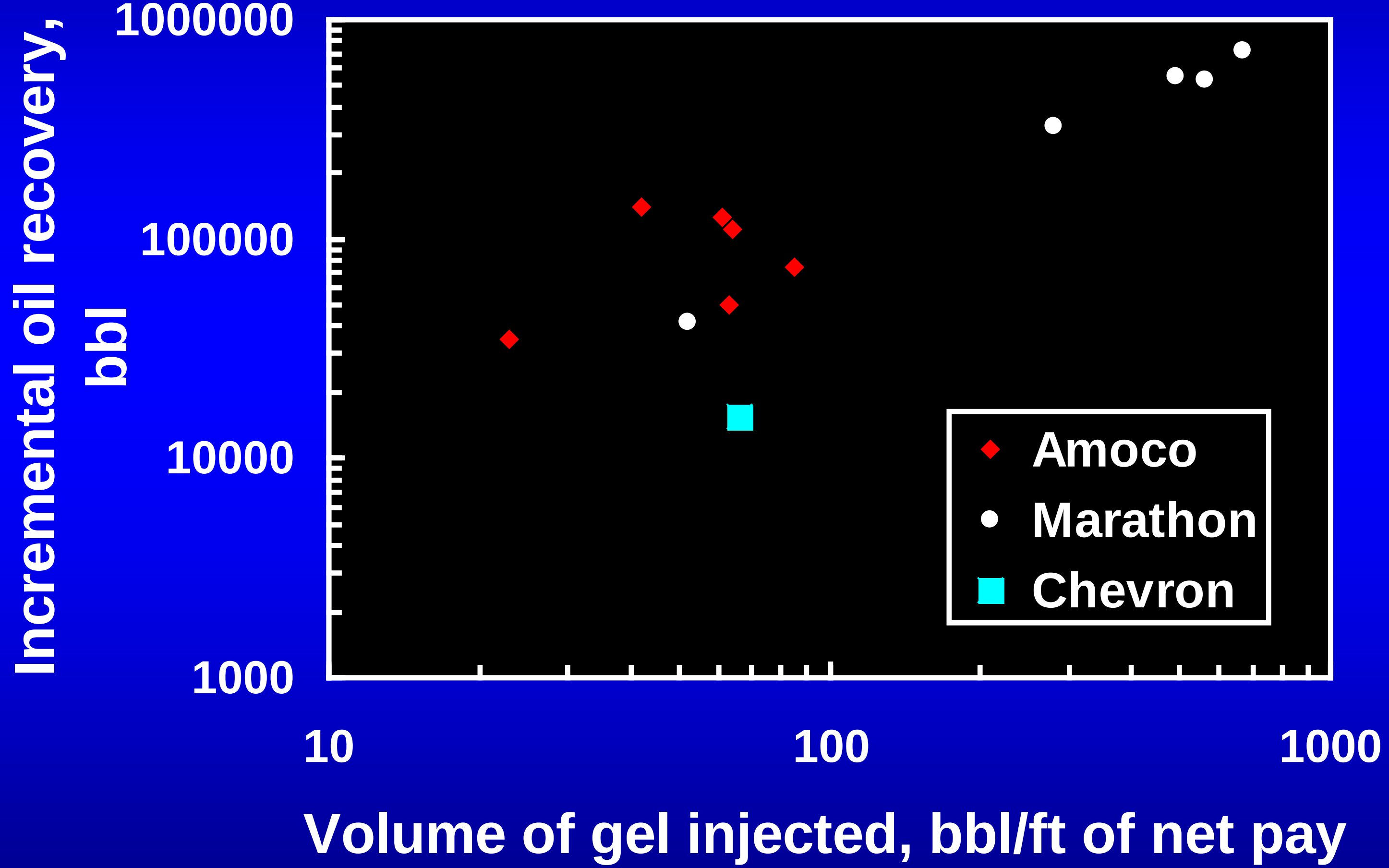
  +20 BOPD, -100 BWPD, -100 MCFPD

SPE 39612: Chevron's Gel Treatments

Lessons Learned

- Rapid communication and associated poor CO_2 economic performance are the most important candidate selection criteria.
- Larger, >15,000 bbl treatments have been successful.
- Chase well treatments are highly successful.
- Best results have been in the best part of the field.
- CO_2 thief should also be H_2O thief.
- H_2O injection rate > 1,200 BPD.
- Avoid high BHP area of field.
- Post-job reservoir management critical.

- Incremental oil recovery generally increased with gel treatment size.



Good Papers Where Naturally Fractured Injection Wells Were Treated

- Amoco's large-volume gel treatments in CO_2 injectors. SPE 27825.
- Marathon's large-volume gel treatments in waterflood injectors. SPE 27779 & *O&GJ* 1/20/92.
- Imperial's large-volume gel treatments waterflood injectors. SPE 38901.
- Chevron's use of multiple methods in the same field, including recompletions, polymer gels, gelled foams, pattern realignment and selective injection equipment. SPE 21649, 27755, 27756, 30730, 35361.
- Kinder Morgan SACROC treatments. SPE 169176

SACROC/KELLY-SNYDER FIELD SPE 169176

- Kinder Morgan WAG CO_2 flood. 19-md limestone.
- 500-1200 sacks of cement worked for some of the worst channeling problems.
- Mechanical methods sometimes helped if distinct zones were watered out.
- Crystalline polymer squeezes were the least successful method.
- 5000-10000 bbl Cr(III)-acetate-HPAM treatments did not last long. Judged too small.
- ~20,000 bbl Cr(III)-acetate-HPAM treatments.
- 5000-12000-ppm HPAM.
- Ending injection of 30,000-ppm HPAM or cement.

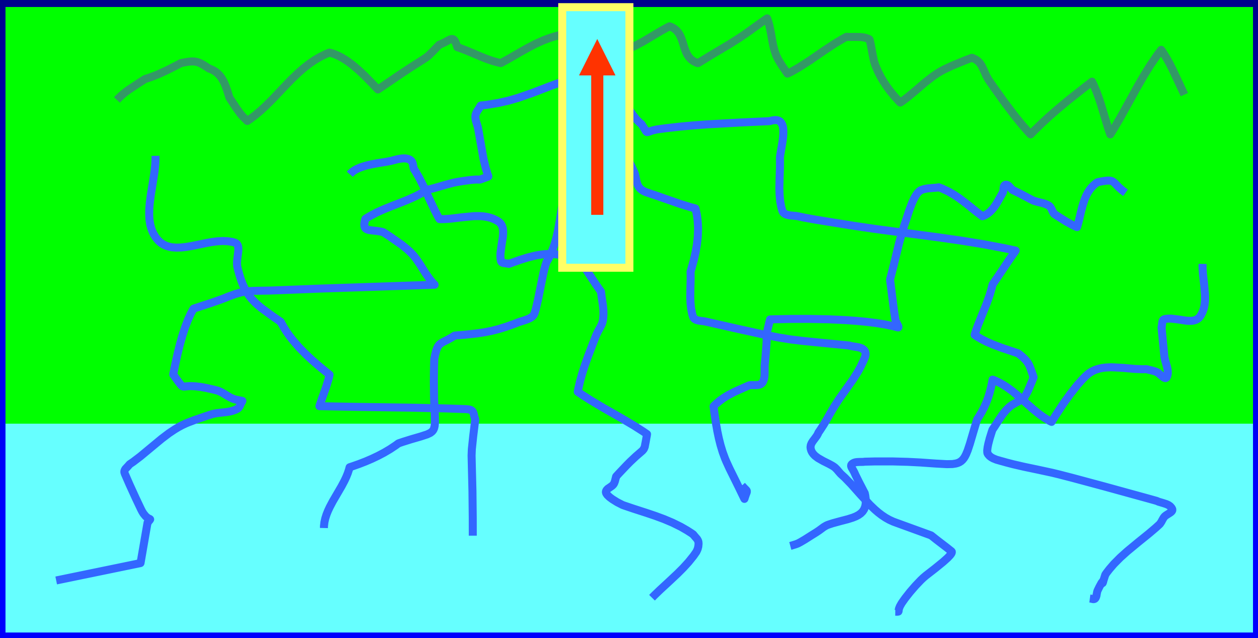
SACROC/KELLY-SNYDER FIELD SPE 169176

- In “P1” area, 29 treatments with ~13000 bbl gel/treatment—reducing GOR from 30 to 20 mcf/bbl and producing 770000 bbl EOR at a cost of $1.88/bbl.
- In “P2” area, 30 treatments with ~17000 bbl gel/ treatment—yielding $1.50 cost/bbl EOR.
- Biggest problem has been produced polymer. Suggested solution: build injection pressure more rapidly (e.g., by increasing HPAM content).
- In total, have injected over one million bbl of polymer during 77 treatments.

DETAILS OF ONE GEL TREATMENT.
KUPARUK RIVER UNIT—ALASKA
SPE 179649

- ConocoPhillips. Miscible hydrocarbon WAG.
- Highly fractured/faulted multilayer sandstone.
- A single 45000-bbl Cr(III)-acetate-HPAM treatment, increasing HPAM from 0.3%-1%.
- Describes detailed methodology associated with the design, execution, and assessment of the treatment.

Natural fracture system leading to an aquifer.



- Many successful polymer/gelant treatments were applied to reduce water production.
- Treatment effects were usually temporary.
- Optimum treatment materials, sizing, and design are currently unknown.
- HOW SHOULD THESE TREATMENTS BE DESIGNED AND EVALUATED?

JPT, April 1993, 356-362
Phillips' Polymer and Gel Treatments in Naturally Fractured Production Wells

- Arbuckle formation of western Kansas.
- Naturally fractured dolomite reservoirs produced by bottom-water drive.
- k ~ 140 md; oil column ~ 20 ft; completion interval ~ 5 ft.
- Pre-treatment production:
  - 5 to 20 BOPD
  - 500 to 1,600 BWPD

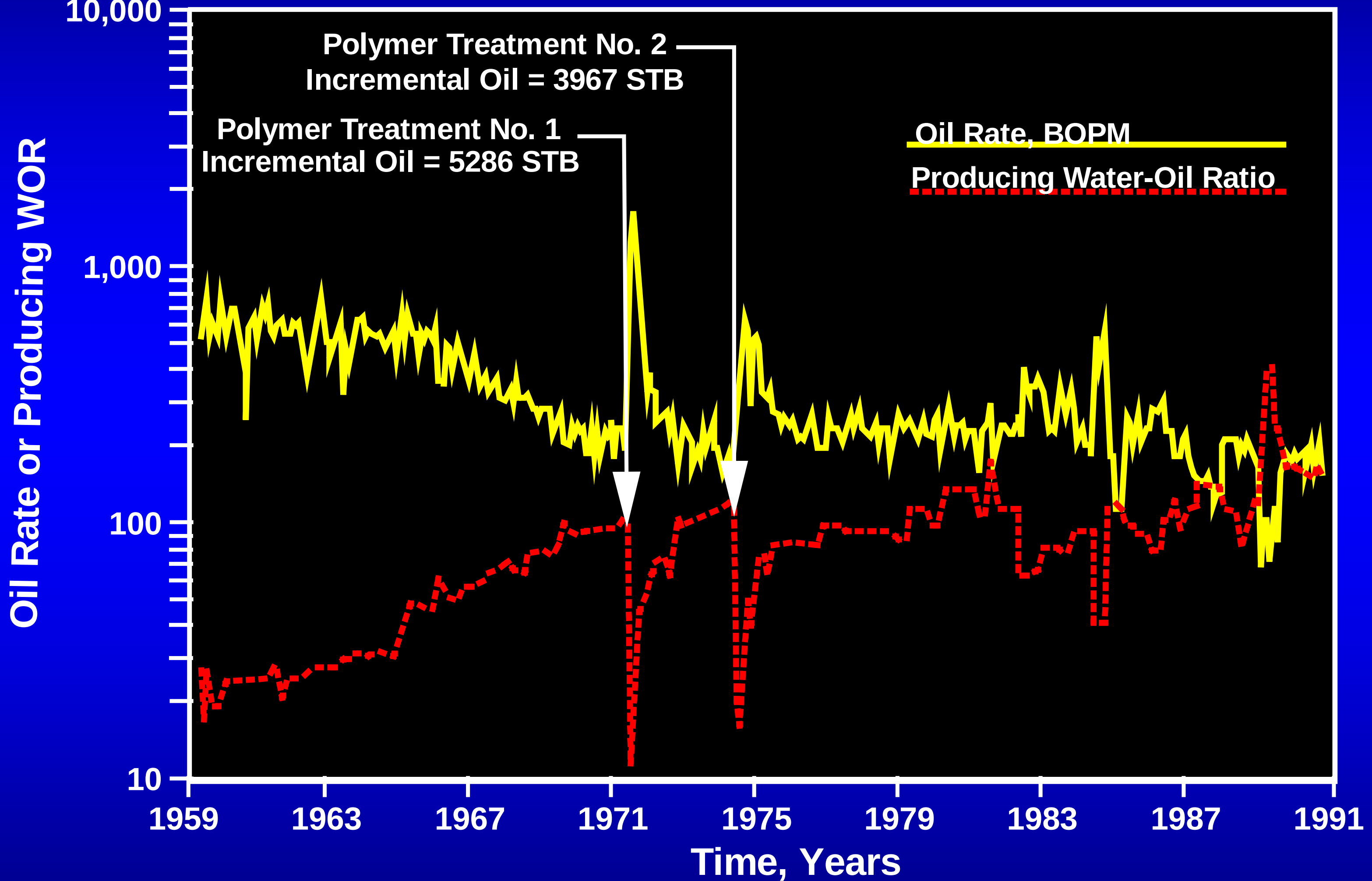
JPT, April 1993, 356-362
Phillips' Polymer and Gel Treatments: Problem Diagnosis

- Reservoirs were well known to be naturally fractured.
- Pretreatment productivities, q/dp, were 10-100 times greater than values expected for unfractured wells.

JPT, April 1993, 356-362
Phillips' Polymer and Gel Treatments: Choice of Treatment, Sizing, and Placement

- Performed in the 1970's -- early in the development of the technology.
- Applied 37 treatments with 8 different polymer-crosslinker combinations.
- Average treatment size: 1070 lbs polymer. (Range: 390 to 1400 lbs).
- Treatments sizes subjective.
- Bullhead injection.

Phillips' well Hendrick #2 production response to polymer treatments (*JPT*, April 1993)



JPT, April 1993, 356-362
Phillips' Polymer and Gel Treatments: Treatment Results

- Average incremental recovery: 1.9 STB/lb polymer. (Range: -1 to 13 STB/lb).
- Average treatment lifetime: 12 months. (Range: 2 to 43 months).
- Gel treatments typically reduced total fluid productivity by a factor of two, so the fractures were restricted but still open.
- Uncrosslinked polymers worked as well as gels.
- Many other materials have been used in the Arbuckle formation. Some say that anything will work.

JPT, April 1993, 356-362
Phillips' Polymer and Gel Treatments: Treatment Results

- IOR, treatment lifetime, and WOR reduction did not correlate well with:
  - lbs. polymer injected (390 - 1,400 lbs/well),
  - type of polymer or gel treatment (8 types used),
  - productivity reduction induced by the treatment (1 - 5),
  - structural position of the completion,
  - completion type,
  - fluid level before the treatment,
  - Arbuckle reservoir.

JPT, April 1993, 356-362
Phillips' Polymer and Gel Treatments: Questions

- Why did IOR not correlate with important variables?
- Why did treatments using uncrosslinked HPAM perform as well as any other type of polymer or gel?
  - Uncrosslinked HPAM has some unknown special property. NO
  - Uncrosslinked HPAM happened to be applied in the best wells. MAYBE
  - pH or other changes induced by the rock inhibited gelation. YES!
- What is the mechanism of action for water shutoff treatments in naturally fractured productions wells?
  - Partial plugging of fractures?
  - Selective plugging of porous rock next to fractures?
  - Other?

Gel Treatments Applied to the Kansas Arbuckle Formation Per SPE Paper 89464

- Over 250 gel treatments had been applied in the Kansas Arbuckle fractured carbonate formation (2000-2003)
- Incremental oil production was the driver for conducting these gel treatments
  - Often reduced water production by a factor exceeding 10 (not mentioned in this paper)

- 7 gel treatments were studied where BHP & buildup pressure data were obtained
  - Water-production rates decreased in every well (53–90%)
  - Incremental oil production obtained from 5 out of 6 wells that were produced for 6 mo.
  - Oil PI increased following the gel jobs
  - Incremental oil production increased with increasing volume of gel injected (for the open hole completions)
  - “The duration of the response should be a function of the volume of gelant injected…”

Economics of Arbuckle Gel Treatments

(Source: PTTC website, R. Reynolds, 10/03)

- ~300 treatments
  - By over 30 operators
  - Analyzed the performance of 37 treated wells
  - Shutoff 110,000,000 bbl water
  - Gross IOP = 1,600,000 bbl oil
- "All of the wells have responded with significant reduction in water production…." (2/03 Reynolds quote)

FIELD OPERATIONAL ISSUES

Robert Lane, SPE 37243

1. Sampling and quality assurance.
2. Polymer handling.
3. Rigup issues.
4. Treatment execution issues.
5. Chemical incompatibilities.
6. Post-treat well operations.