

# Pushing Out the Oil with Conformance Control

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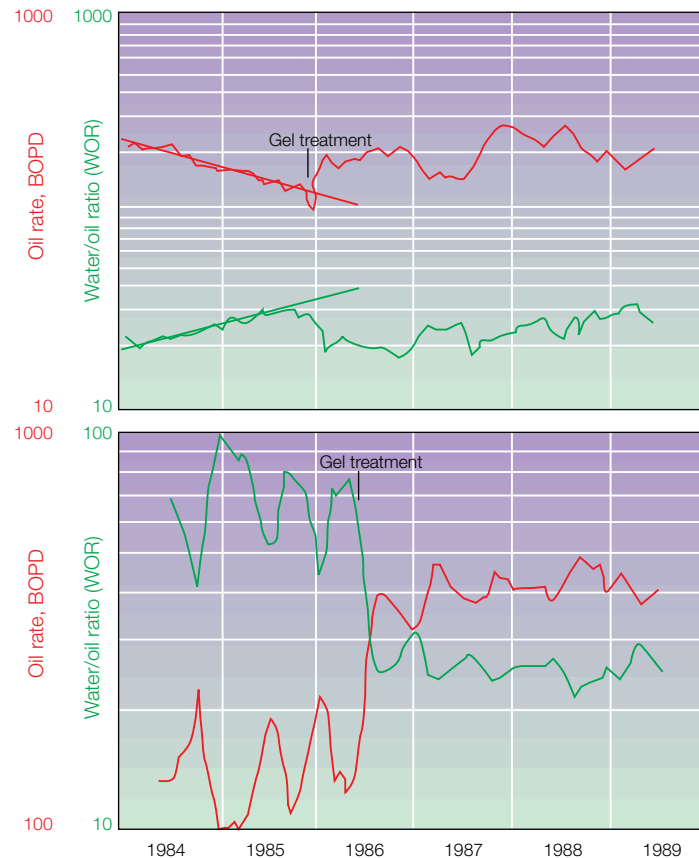
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**The growing problem of water production and a stricter environmental enforcement on water disposal are forcing oil companies to reconsider conformance control—the manipulation of a reservoir’s external fluid drive to push out more oil and less water. The technical challenges range from polymer chemistry to detailed knowledge of reservoir behavior.**

By late 1984, after several years’ research, Marathon Oil Company laboratories in Littleton, Colorado, USA established a new polymer-gel system to block high-permeability channels within a reservoir and improve oil recovery. Previous attempts using less sophisticated chemistry had failed because the chemicals had become unstable at reservoir conditions and also were partially toxic. But now the chemistry looked right. During the next three years, Marathon performed 29 treatments with the new system in nine of its fields in Wyoming’s Big Horn basin. Fourteen treatments were in carbonate formations, and 15 were in sandstones.<sup>1</sup>

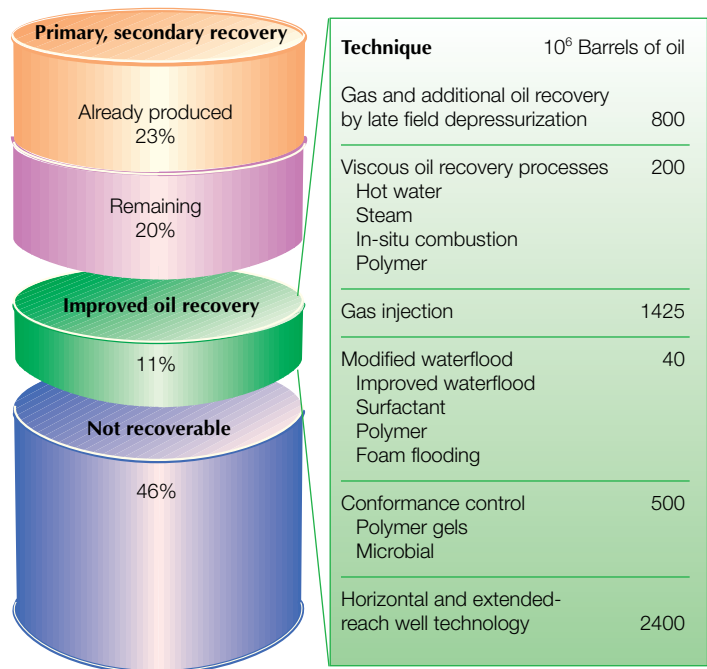
The greatest success occurred when injection wells were treated. The Big Horn reservoirs are known to be naturally fractured and the injected polymer-gel system most likely filled much of the fracture system between injector and neighboring producer. This would force subsequent water-



□ Two examples of production reversal during Marathon Oil Company’s conformance control campaign in Wyoming’s Big Horn basin. In each case, Marathon injected a polymer-gel system into an injector and noted the production response in adjacent producers. Both examples show a dramatic reversal of both declining oil rate and increasing water/oil ratio (WOR)—see straight-line trends in top figure. On average, each extra barrel of oil derived from their series of 29 treatments cost Marathon just \$0.34.

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In this article, DGS is a mark of Dowell, FLOPERM is a mark of Pfizer Inc., and MARCIT and MARA-SEAL are marks of Marathon Oil Company.



□ The UK Department of Trade and Industry's estimate of improved oil recovery (IOR) potential in the UK North Sea and the proportion expected to be produced with conformance control.

drive to enter the matrix rock or fractures untouched by the treatment and push out oil. In many cases, a declining production in the neighboring producer was dramatically reversed, staying that way for several years (*previous page*).

Overall, the 29 treatments yielded 3.7 million barrels more oil than if the treatments had never been done, at a total cost of just \$0.34 per barrel. Considering the price of oil at the time ranged from \$30 to \$24, Marathon had got themselves some very inexpensive production and a clear signal that the age of conformance control had begun.

### What is Conformance Control?

In the context of a reservoir produced with some kind of external fluid drive, conformance describes the extent to which the drive uniformly sweeps the hydrocarbon toward the producing wells. A perfectly conforming drive provides a uniform sweep across the entire reservoir; an imperfectly conforming drive leaves unswept pockets of hydrocarbon. Conformance control describes any technique that brings the drive closer to the perfectly conforming condition—in other words, any technique that somehow encourages the drive mechanism to mobilize rather than avoid those hard-to-move pockets of unswept oil and gas.

In the pantheon of techniques to improve oil recovery, conformance control is relatively unambitious, its goal being simply to

improve macroscopic sweep efficiency. Most enhanced oil recovery (EOR) techniques, for example, also strive to improve microscopic displacement efficiency using a variety of surfactants and other chemicals to prize away hydrocarbon stuck to the rock surface. Conformance control is also less expensive than most EOR techniques because the treatments are better targeted and logistically far smaller.

Another factor also favors conformance control. By redistributing a waterdrive so it sweeps the reservoir evenly, water cut is often dramatically reduced. For many mature reservoirs, treatment and disposal of produced water dominate production costs, so less water is good. Environmental regulations also push oil companies to reduce water production. In the North Sea, residual oil in produced water dumped into the ocean is restricted to 40 ppm, an upper limit increasingly under pressure from the European Community. In environmentally sensitive areas such as the Amazon rain forest, water disposal is also a major issue.

In a recent survey by the British Government Department of Trade and Industry (DTI) that reviewed the full spectrum of improved oil recovery (IOR) techniques and their potential for the UK North Sea, conformance control accounted for a possible further 500 million barrels of oil (*above*).<sup>2</sup> This constitutes 10% of the total IOR potential of

more than five billion barrels and contributes to raising final oil recovery from the 43% obtained using primary and conventional secondary recovery methods to 54%, an increase of 11%. Unlike many of the IOR techniques reviewed by the DTI, conformance control technology was judged mature enough to use immediately.

Conformance control during waterflooding covers any technique designed to reduce water production and redistribute waterdrive, either near the wellbore or deep in the reservoir. Near the wellbore, these techniques include unsophisticated expedients such as setting a bridge plug to isolate part of a well, dumping sand or cement in a well to shut off the bottom perforations, and cement squeezing to correct channeling and fill near-well fractures. Deep in the reservoir, water diversion needs chemical treatment.

Initially, straight injection of polymer was tried but proved uneconomical because of the large volumes required to alter reservoir behavior and because polymers tend to get washed out. The current trend is gels, which if correctly placed can do the job

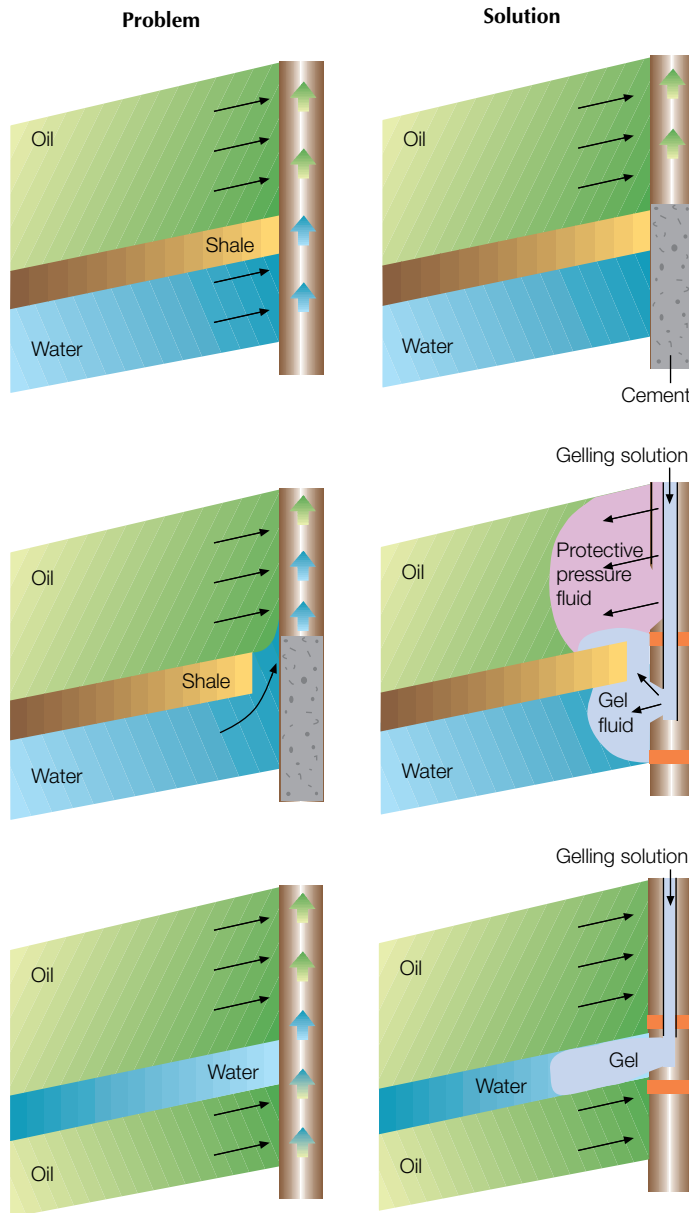
1. Sydansk RD and Moore PE: "Production Responses in Wyoming's Big Horn Basin Resulting From Application of Acrylamide-Polymer/Cr(III)-Carboxylate Gels," paper SPE 21894, 1990, unsolicited.
2. Coleman B: "DTI's IOR Strategy" in *Best Practices for Improved Oil Recovery*. London, England: IBC Technical Services Ltd, 1993.

more efficiently with much smaller volumes. In the future, potentially less expensive foams including foamed gel may be tried. Ultimately, reducing water production may require a new well. The choice of technique or combination of techniques depends crucially on the reservoir and its production history.

Take, for example, the case of two producing zones separated by an impermeable shale, in which the bottom zone has watered out (*right*). The first solution is to cement in the bottom zone. Suppose, though, that the shale barrier does not extend to the producing well. Then success with the cement plug becomes short-lived and water soon starts coning toward the top interval. The only recourse now is to inject a permeability blocker—some kind of gelling system—deep into the lower zone. The trick is not letting the gelling system invade the upper zone. This can be achieved by pumping through coiled tubing to the top of the watered-out zone while simultaneously pumping an inert fluid, water or diesel fuel through the annulus into the upper zone to prevent upward migration of the gelling system.

Deep gelling systems are also the answer for a high-permeability but watered-out formation sandwiched between two lower permeability formations—the classic breakthrough scenario. A casing patch or cement squeeze may halt water production momentarily, but long-term shutoff requires a deeper block. The fractured reservoir is a variant of this scenario. If natural fractures are interconnected, they can provide a ready conduit for water breakthrough, leaving oil in the matrix trapped and unproductive. The solution is to inject and fill the fractures with a gelling system, that once gelled, forces injection water into the matrix to drive the oil out.

The possibilities are endless, and there are as many solutions to blocking water production as there are reservoirs to block.<sup>3</sup> The challenges for the reservoir engineer contemplating conformance control are knowing why, where and how water is produced, and which water blocking technique to use. In the case of using a gelling system, there are the additional challenges of being sure



Multiple causes of early water production during a waterdrive. Top: a watered-out zone separated from an oil zone by an impermeable shale barrier—the solution is to cement in the bottom zone. Middle: same as above but the shale barrier does not reach the production well—cementing does not work, so the solution is to inject gel into the lower zone while balancing the upper zone pressure with inert fluid. Bottom: watered-out high-permeability zone sandwiched between two oil zones—the solution is to isolate the zone and inject gel. (Adapted from Morgan, reference 3.)

that the chemistry is robust enough to go where it is intended, deep in the reservoir, and that it is formulated correctly to actually gel. The combination of these challenges is daunting and explains conformance control's checkered history. If the technique is more widely accepted today, it is only because these challenges are now recognized, not because they are resolved.

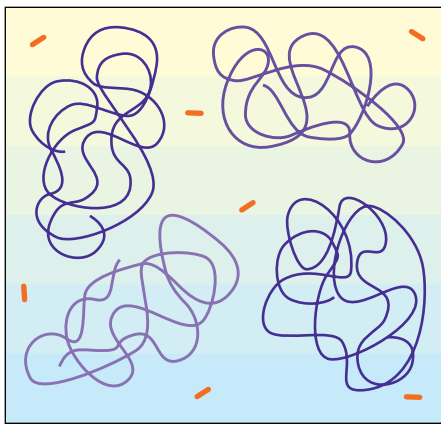
We'll next look at the chemistry of gelling systems, the predominant method of blocking permeability and redistributing water-drive, and then illustrate the care successful proponents of the technique must exercise in choosing and implementing treatments.

### Gelling System Chemistry

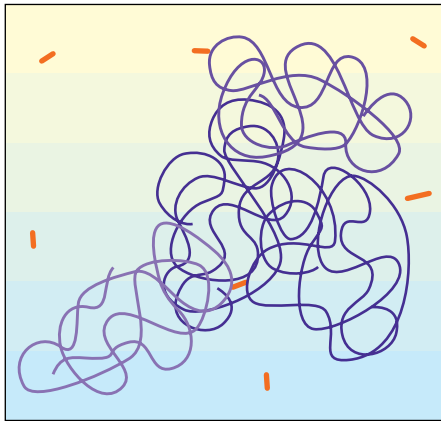
Phillips pioneered the first polymer gels for conformance control in the 1970s. Since then, research into gelling systems has been maintained at an intense level.<sup>4</sup> Polymer gel systems start as a flowing mixture of two components—high-molecular weight polymer and another chemical called a cross-linker. At some trigger, each cross-linking molecule, tiny compared with the polymer molecule, starts attaching itself to two polymer molecules chemically linking them together (*next page, left*). The result is a three-dimensional tangle of interconnected polymer molecules that ceases behaving like a fluid and can eventually constitute a rigid, immobile gel.

The trick in designing these systems is finding chemicals that are insensitive to the

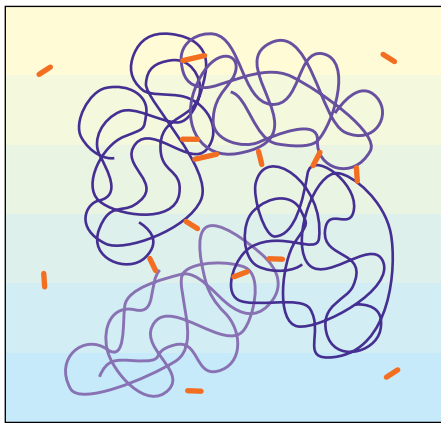
**Pre-gel**



**Cross-linking Begins**



**Gel Formed**



□ Gel formation as cross-linking molecules (red) connect polymer molecules (purple).

widely varying conditions of the subsurface, such as temperature, the ionic composition of the connate water, its pH, the presence of either carbon dioxide [CO<sub>2</sub>] or hydrogen sulfide [H<sub>2</sub>S], and the absorptivity of the rock grains, to name a few. The polymer may be naturally occurring or manufactured synthetically. The cross-linker may be metal ions or metallic complexes that bond ionically to the polymer, or organic molecules that bond covalently.

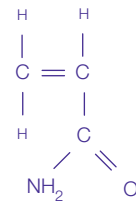
There have been innumerable systems developed since the 1970s, too many to describe, so we will concentrate on the evolution of a particularly promising system that uses the synthetic polymer called polyacrylamide (PA).<sup>5</sup> This readily available polymer comprises a carbon-carbon backbone hung with amide groups, possibly tens of thousands of them to provide molecular weights in the millions (*below*). In its pure state, the polymer is electrically neutral, seeming to preclude any cross-linking through ionic bonding. However, when mixed with a little alkaline solution, such as sodium hydroxide, or when subjected to elevated temperature, some of the amide groups convert to carboxylate groups. Each of these carries a negative charge. The proportion of amide groups that convert to carboxylate is called the degree of hydrolysis (DH) and typically varies from 0 to 60%. In this form, the poly-

mer is called partially hydrolyzed polyacrylamide (PHPA) and with its negatively charged carboxylate groups becomes susceptible to ionic cross-linking.

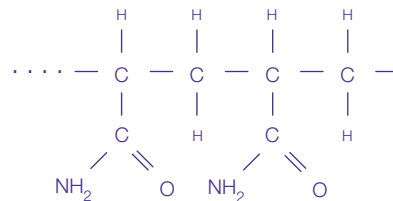
Efficient cross-linkers are trivalent metal ions such as aluminum, Al<sup>3+</sup>, and chromium, Cr<sup>3+</sup>. These can be packaged either as simple inorganic ions in solution or within soluble chemical complexes in which the trivalent ion is associated with small inorganic or organic groups called ligands. Some of the first polymer-gel systems from the early 1970s used aluminum in the form of aluminum sulfate. Whatever the choice, the trivalent metal ion readily links carboxylate

3. Morgan J: "State-of-the-Art of Water Shut-off Well Treatments" in *Best Practices for Improved Oil Recovery*. London, England: IBC Technical Services Ltd, 1993.
- Seright RS and Liang J: "A Survey of Field Applications of Gel Treatments for Water Shutoff," paper SPE 26991, presented at the 1994 SPE Permian Basin Oil & Gas Recovery Conference, Midland, Texas, USA, March 16-18, 1994.
4. Needham RB, Threlkeld CB and Gall JW: "Control of Water Mobility Using Polymers and Multivalent Cations," paper SPE 4747, presented at the SPE Improved Oil Recovery Symposium, Tulsa, Oklahoma, USA, April 22-24, 1974.
5. For a general review:  
Sorbie KS: *Polymer-Improved Oil Recovery*. Glasgow, Scotland: Blackie, 1992.  
Woods CL: *Review of Polymers and Gels for IOR Applications in the North Sea*. London, England: HMSO Publications Centre, 1991.

**Amide Monomer**

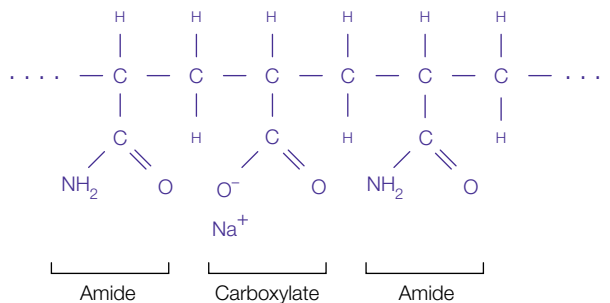


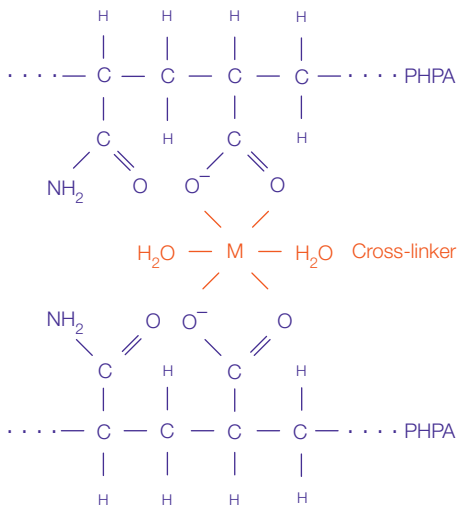
**Polyacrylamide (PA)**



□ **Chemical structures of the amide monomer, polyacrylamide polymer (PA) and partially hydrolyzed polyacrylamide polymer (PHPA) with its negatively charged carboxylate groups.**

**Partially Hydrolyzed Polyacrylamide (PHPA)**





□ **Chemical linking of partially hydrolyzed polyacrylamide polymer (PHPA) molecules with trivalent metal ions, indicated generically as  $M^{3+}$ .**

groups on different polymer molecules, or possibly on the same molecule (*above*). Relatively few cross links are needed to ensure that the polymer-cross-linker mixture gels.

The chemical environment deep in an oil reservoir, however, often conspires to wreck this idealized picture. In the case of aluminum sulfate, cross-linking is very much pH dependent. While the mixture remains acidic, no gel forms so the treatment fluids can be safely injected into the reservoir. But when the fluids hit the reservoir, pH rises rapidly and gelling occurs immediately. The

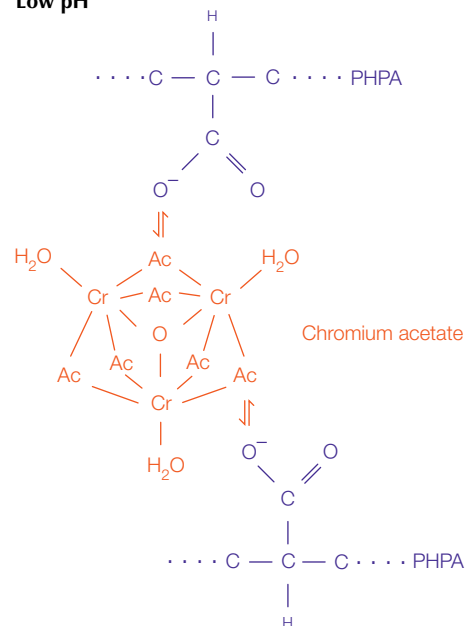
system therefore worked only very near the wellbore and suffered from total lack of control—gelling time was entirely at the mercy of the reservoir environment.

Toward the 1980s,  $Cr^{3+}$  rather than  $Al^{3+}$  was tried as the cross-linker, not because it provided better cross-linking, but because it promised better gelation control. The technique to achieve this, though, was not to use  $Cr^{3+}$  directly but rather  $Cr^{6+}$ . This ion is inert with respect to cross-linking but can be reduced to  $Cr^{3+}$  using a variety of reducing agents that could be injected with the treatment fluids. In theory, this would allow the system to be injected deep into the formation before gelling.

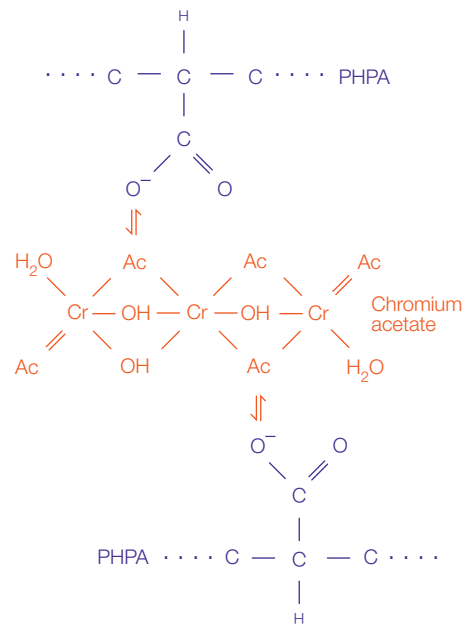
In practice, however, there were three problems. It was difficult to provide sufficiently long gelation times at high temperature; the whole system was sensitive to  $H_2S$ —itself a reducing agent; and, worst,  $Cr^{6+}$  was recognized as toxic and even carcinogenic. These problems appeared to be resolved in the mid 1980s when an environmentally friendly, controllable chromium system was developed at the Marathon Petroleum Technology Center in Littleton, Colorado, USA.<sup>6</sup>

Scientists there had the idea of packaging  $Cr^{3+}$  as the metal-carboxylate complex, chromium acetate. The acetate group has a structure very similar to the carboxylate groups on PHPA polymer (*right*). Thus, the  $Cr^{3+}$  ion is attracted to both the acetate ligand within the complex and the carboxylate groups on the PHPA polymer. This slows the

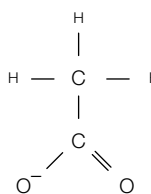
Low pH



High pH



Ac is



□ **Chemical structure of chromium acetate complexes as a function of pH and its linking with PHPA.** (Adapted from Tackett JE: "Characterization of Chromium (III) Acetate in Aqueous Solution," *Applied Spectroscopy* 43 (1989): 490-499.)



Tonguing

Intermediate

Rigid

□ **Marathon's MARCIT gel in three final states depending on concentration, from left: tonguing gel, intermediate strength gel and rigid gel.** (Courtesy of Marathon Oil Company.)

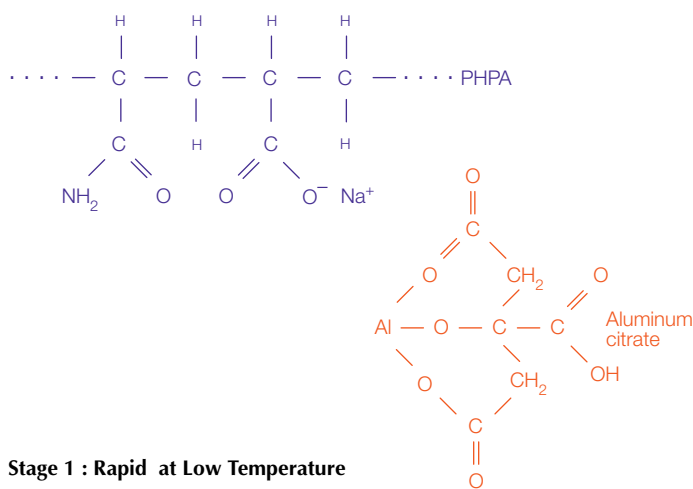
cross-linking process and ultimately gives the chemist effective control over gel time.

Substantial laboratory testing showed that the behavior of the PHPA-chromium acetate system was insensitive to pH from about 2 to 12.5, relatively insensitive to ions in formation fluids, and untroubled also by H<sub>2</sub>S and CO<sub>2</sub>. Furthermore, it could be formulated to give a wide range of gel strengths and gel times at temperatures up to 124°C [255°F] and even higher. Marathon now licenses this system in two forms. Its MARCIT system using PHPA polymer with a molecular weight of more than five million is designed for filling and blocking fractures, as used for example in the Wyoming trials (*previous page, bottom left*). Its MARA-SEAL system using PHPA with a low molecular weight in the mere hundreds of thousands and lower DH has reduced pre-gel viscosity and is designed for filling and blocking matrix reservoir rock.

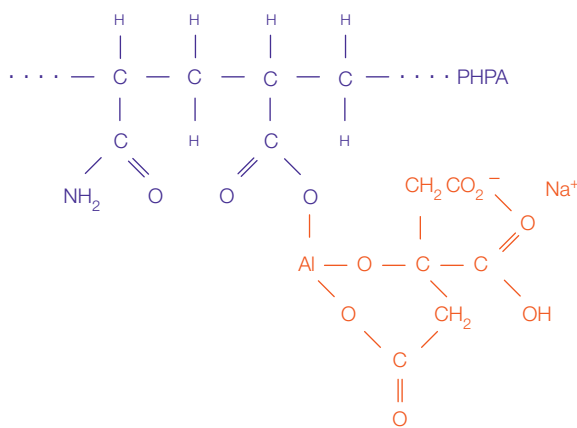
The chemistry and physics of polymer gels are complex and often controversial. One point of dispute is whether polymers such as PHPA, even with relatively low molecular weights, as in MARA-SEAL, can be successfully injected through narrow pore throats into reservoir matrix rock. Marathon's laboratory tests suggest they can, although reservoir conditions may not have been duplicated exactly. Others believe that because of the interaction of the polymer with the pore walls and the very size of the polymer molecule, the systems have difficulty negotiating small pore spaces, limiting injection. The need for matrix-filling gel systems, though, is not in dispute.

BP Exploration and ARCO are currently testing a system comprising PHPA and an aluminum-based cross-linker that is hoped will reach deep in the matrix reservoir of the Kuparuk field in Northern Alaska. The cross-linker is another metal-carboxylate complex, aluminum citrate. But unlike chromium acetate, this links the PHPA in two distinct temperature-controlled stages (*right*).<sup>7</sup> In the first stage which occurs rapidly in cold water, each aluminum citrate

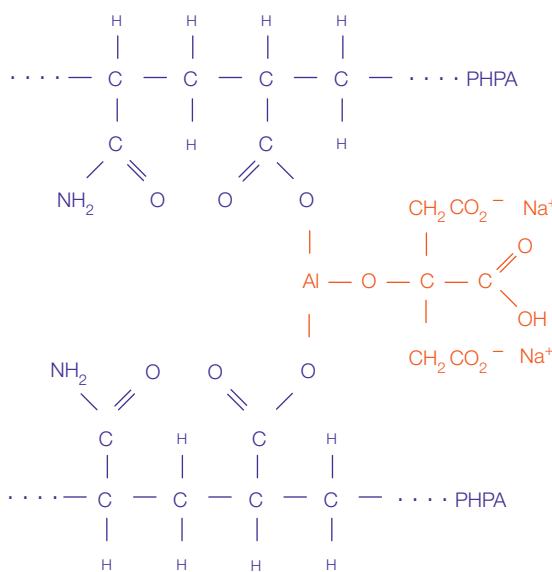
### Pre-gel



### Stage 1 : Rapid at Low Temperature



### Stage 2 : Rapid at High Temperature



6. Sydansk RD: "A New Conformance-Improvement-Treatment Chromium (III) Gel Technology," paper SPE/DOE 17329, presented at the SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, Oklahoma, USA, April 17-20, 1988.

7. Fletcher AJP, Flew S, Forsdyke IN, Morgan JC, Rogers C and Suttles D: "Deep Diverting Gels for Very Cost-Effective Waterflood Control," *Journal of Petroleum Science and Engineering* 7 (1992): 33-43.

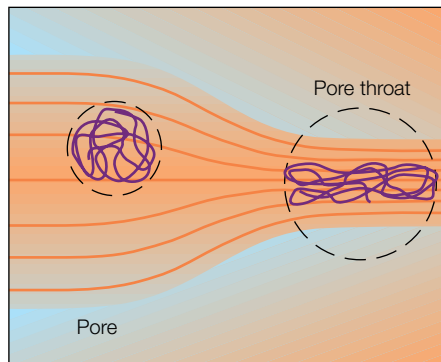
Rogers C, Morgan JC and Forsdyke IN: "Deep Diverting Gels for Improved Profile Control," in *Oil and Gas Technology in a Wider Europe: Proceedings of the 4th EC Symposium, Berlin, Germany, November 3-5, 1992*. Aberdeen, Scotland: Petroleum Science and Technology Institute (1992): 381-399.

□ **Two-stage cross-linking using PHPA and aluminum citrate, being used by BP Exploration and ARCO in the Kuparuk field, Alaska.**

molecule bonds to just one polymer carboxylate site. In the second stage, which occurs only above 50°C [122°F], the aluminum citrate complex can attach to a second carboxylate group thereby cross-linking two polymer molecules and contributing to produce a gel network. Because the cross-link itself contains carboxylate groups and these have an affinity for water molecules, the formed gel may flow in a beaker, yet provide an adequate permeability block in porous rock.

BP and ARCO's strategy is to pump the system into the reservoir through injection wells, where the cooler temperature of the injection water will promote only the first-stage reaction, resulting in a pumpable fluid of low viscosity. Then, as the fluid permeates deep into high-permeability sections of the reservoir and experiences higher temperatures, the second-stage will kick in and enough of a gel will form to divert water-drive to less permeable zones. In preparation for field tests, BP conducted an extensive computer simulation of the temperature distribution and likely flow patterns of the polymer-gel system within the reservoir, and also laboratory studies of the system injectability through 190-ft [58-m] long slimtubes packed with sand (*below*). It is too early to tell whether their ambitious plan is working in the field.

The problem of injecting polymer gel systems through the narrow pore spaces of matrix is multifaceted and has been a focus



□ **Schematic of polymer molecule elongating within pore throat. As the molecule elongates, its effective hydrodynamic volume and therefore also its viscosity increase, impeding injection.**

of a three-year Department of Energy project at the New Mexico Institute of Mining and Technology in Socorro, New Mexico, USA.<sup>8</sup> At the pore scale, there are three main issues. First, some of both the polymer and cross-linker will get adsorbed onto the pore walls during injection. In itself, fluid retention is not a problem as long as most of the treatment fluid reaches its destination deep in the reservoir. More serious is if the absorptivity rates of the two components are different. Then, the volumetric ratio of polymer to cross-linker will change as the treatment invades the formation, possibly compromising control of gelling time. BP's aluminum citrate system may overcome this hazard because the cross-linker makes its first

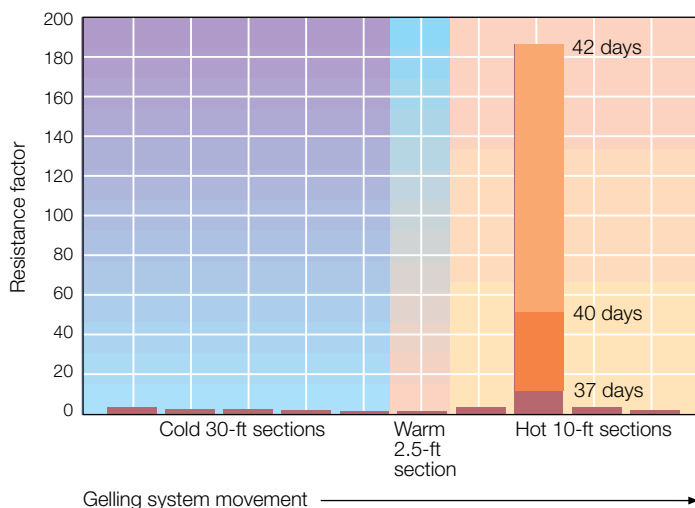
attachment to the polymer before injection, rendering the two components inseparable.

The second issue is polymer elasticity. Polymers being long, complex molecules exhibit a degree of elasticity that makes how they move somewhat dependent on their surroundings. For example, the viscosity observed in a free polymer solution will not necessarily be mirrored when the same polymer is trying to squeeze through a pore throat (*left*). In general, polymer elasticity inhibits the progress of treatment fluid through porous medium. Third, there is the question of pore throats actually becoming blocked by microclusters containing several polymer molecules—these may develop prior to bulk gelling.<sup>9</sup> All three issues are being researched and to an extent represent the key to leaping from laboratory evidence to certainty on what happens in the field.

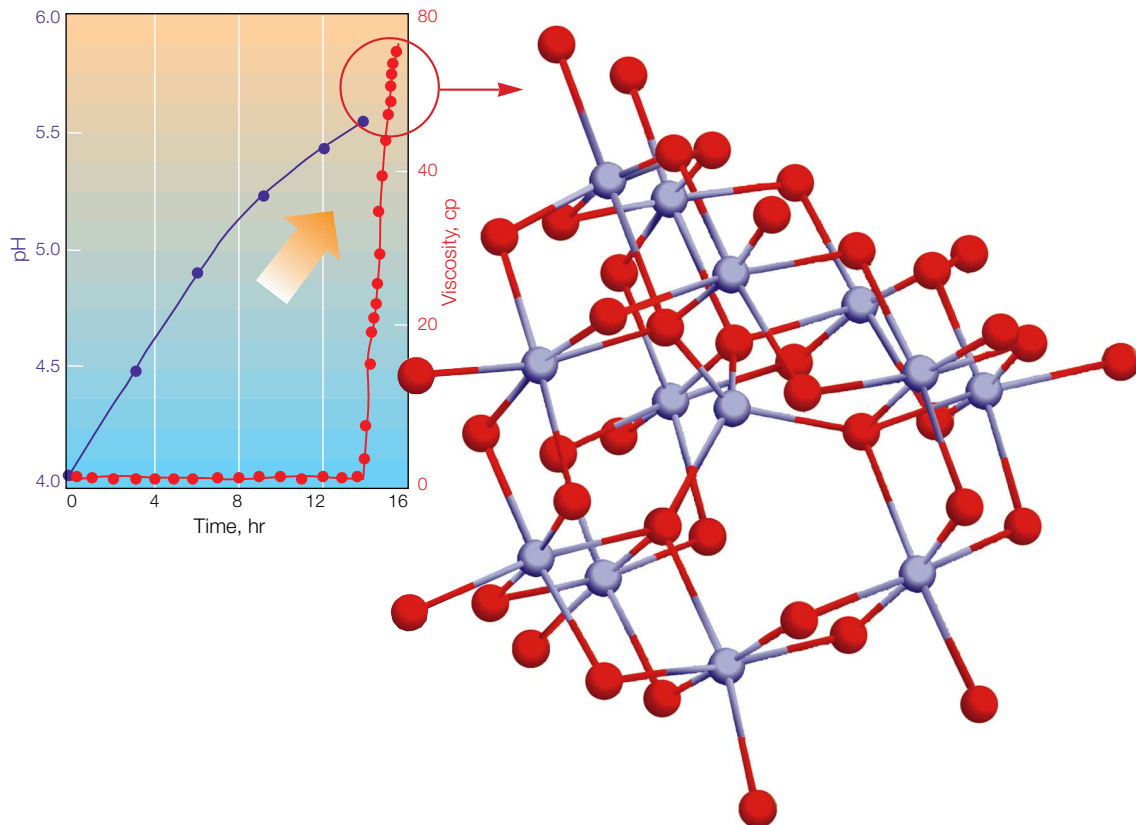
### Inorganic Gelling Systems

An alternative gelling system that guarantees injectability into matrix rock uses simple inorganic chemicals that have flowing properties nearly identical to those of water. Inorganic gels were discovered in the 1920s and are used to this day for plugging lost circulation, zone squeezing and consolidating weak formations. Their failing for conformance control has been a very rapid gelation time, but recent innovations using aluminum rather than silicon have resolved this problem. An example is the DGS Delayed Gelation System developed by the Schlumberger pumping company, Dowell.<sup>10</sup>

The DGS system comprises partially hydrolyzed aluminum chloride that precipitates to a gel when an activator responds to temperature and raises the system pH above a certain value (*next page*). A gel materializes because aluminum and hydroxyl ions link with each other in such a way as to form an amorphous, irregular three-dimensional impermeable network. The DGS system is quite insensitive to the subsurface environment, except for the caution that divalent anions in the formation water, such as sulfates and carbonates,  $\text{SO}_4^{2-}$  and  $\text{CO}_3^{2-}$ , can enter the system and affect the gel structure. Conformance control with the DGS system has been tried with success from Australia to South America (see "Profile



□ **Resistance factors to PHPA-aluminum citrate injection, measured along a 190-ft slimtube packed with sand, in experiments by BP Exploration. The gelling system remains fluid in cold and warm sections of the slimtube; it fully gelled only some way into the hot section, once it arrived there 37 days after injection began. (Adapted from Fletcher et al., reference 7.)**



□ **Development of Dowell DGS gel as the system pH increases, with postulated gel structure showing aluminum atoms in blue and oxygen atoms in red. Hydrogen will be loosely associated with the exterior, singly bonded oxygen atoms.**

Modification Using DGS Gelling System," next page).

Besides their inherent ability to deeply permeate matrix rock, inorganic gels have another advantage over their polymer-based cousins. If the treatment fluid gets incorrectly placed causing a deterioration in reservoir performance, inorganic gel can be removed with acid. Of course, the acid has to be able to reach the gel to be able to remove it. Polymer gels, on the other hand, cannot be dismantled easily and are therefore usually in place for the duration.

If deep penetration in matrix is one key factor in the conformance control debate, another concern is contamination of the gelling system through contact with ions in the formation water. As noted, the DGS system may be adversely affected by divalent anions. PHPA, on the other hand, both before and after gelling may be affected by

divalent cations such as  $\text{Ca}^{2+}$ , which are relatively ubiquitous in formation waters.  $\text{Ca}^{2+}$  ions associate with the carboxylate groups in PHPA causing free polymer to precipitate. This becomes more of a problem as the degree of hydrolysis of the polymer increases, and DH can increase with increasing temperature. Research initiated at Phillips Petroleum Co. and pursued further at Eniricerche SpA, Italy's national research center for the oil industry situated near Milan, has identified other polymer types that may offer better protection from ionic attack yet still be susceptible to ionic cross-

8. Seright RS and Martin FD: Fluid Diversion and Sweep Improvement with Chemical Gels in Oil Recovery Processes, Annual Report for the Period May 1, 1989 - April 30, 1990. Bartlesville, Oklahoma, USA: U.S. Department of Energy, 1991: DOE/BC/14447-8.  
Seright RS and Martin FD: Fluid Diversion and Sweep Improvement with Chemical Gels in Oil Recovery Processes, Second Annual Report for the Period May 1, 1990 - April 30, 1991. Bartlesville, Oklahoma, USA: U.S. Department of Energy, 1991: DOE/BC/14447-10.  
Seright RS and Martin FD: *Fluid Diversion and Sweep Improvement with Chemical Gels in Oil Recovery Processes*, Final Report and Third Annual Report for the Period May 1, 1991 - April 30, 1992. Bartlesville, Oklahoma, USA: U.S. Department of Energy, 1992: DOE/BC/14447-15.
9. Todd BJ, Willhite GP and Green DW: "A Mathematical Model of In-Situ Gelation of Polacrylamide by a Redox Process," *SPE Reservoir Engineering* 8 (February 1993): 51-58.
10. Chan KS: "Reservoir Water Control Treatments Using a Non-Polymer Gelling System," paper OSEA 88134, presented at the 7th Offshore South East Asia Conference, Singapore, February 2-5, 1988.

## Profile Modification Using DGS Gelling System

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Canning Vale, Western Australia

The following two conformance control case studies describe a producer that is watered-out from coning (Venezuela) and water injectors that have poor injection profiles (Australia).

### Venezuela

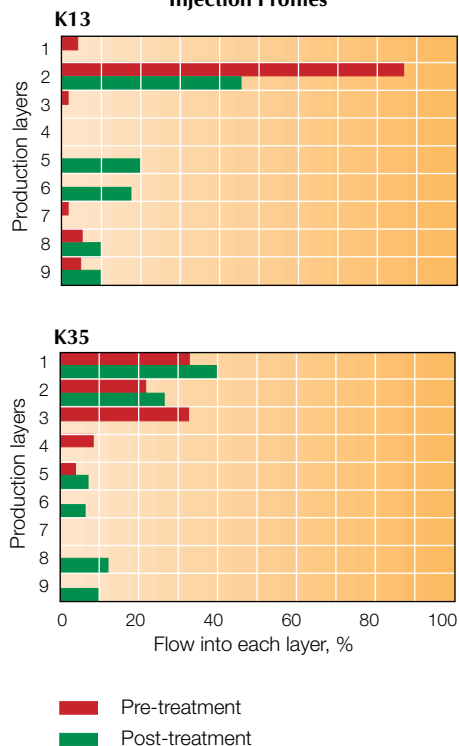
In Venezuela, oil company Corpoven, S.A. has been evaluating several gelling systems at its national research center INTEVEP. Laboratory analysis narrowed its choice to the inorganic DGS system of Dowell and Pfizer Inc.'s FLOPERM system. The FLOPERM system uses a monomer called melamine—a monomer comprises a single chemical group from which polymer is built—and an organic covalent-bonding cross-linker, in this case formaldehyde, to form polymer gels in situ.<sup>1</sup> In the field, Corpoven tried the DGS system in two wells, the FLOPERM system in one well, and both systems in a fourth well with each system restricted to a different producing zone.

The most successful treatment was in one of the two wells receiving the DGS system only. The treatment was designed to block water coning at the bottom of an oil producer in a zone 6 ft [2 m] thick. The reservoir was an 80-md limestone at 9145 ft [2787 m]. Downhole static temperature was 140°C [284°F], high for most commercially available gelling systems.

During a period of 10 hours, 300 barrels of DGS treatment fluid were pumped through tubing and packer into the watered-out zone at 0.5 bbl/min. Simultaneously, diesel fuel was pumped down the annulus above the packer into the overlying oil zone to prevent the treatment fluid from entering the oil zone. The treatment fluid was then displaced with 78 barrels of water and allowed to gel for a week.

When the well was put back on production, oil production increased more than 2.5 times and water cut had dropped 25%. Eleven months later, 36,000 additional barrels of oil had been produced and water cut was still 15% less than before the treatment.

### Injection Profiles



□ Injection profiles in wells K13 and K35 before and after pumping DGS gelling system into the lower five layers. Conformance is not perfect after the treatment, but at least the lower layers are now taking some of the injected water. (Courtesy of WAPET.)

### Australia

In the Barrow Island field in Western Australia, Western Australian Petroleum (WAPET) has been deploying DGS treatments in injector wells to redistribute waterdrive to low-permeability parts of their multilayered, predominantly nonfissured reservoir. In two injection wells, K35 and K13, the top three of a total of nine reservoir sand layers were taking almost all the injection water—about 100 BWPD. The bottom six layers were getting practically nothing.

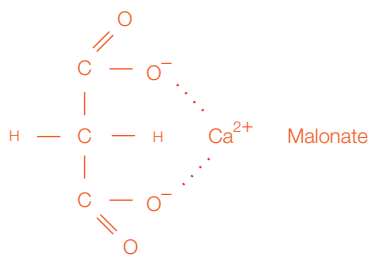
In a treatment design that was similar for both wells, WAPET placed a plug below the third layer and injected about 400 barrels of DGS system over three to four days, anticipating that the treatment fluid would invade at least 20 ft [6 m] into the reservoir matrix. After allowing the gel enough time to set, they then reperforated the lower zones and began reinjecting water. As might be expected, injection rates were less than before—74 versus 150 BWPD in K13 and 105 versus 120 BWPD in K35—due to the plugging action of the gel. But the injection was better distributed, as shown by tracer surveys (left). The top layers still take their fair share, but now the bottom layers also take some water. Correspondingly, water cut in adjacent producers dropped by more than 50%.

1. Chang PW, Goldman IM and Stingley KJ: "Laboratory Studies and Field Evaluation of a New Gelant for High-Temperature Profile Modification," paper SPE 14235, presented at the 60th SPE Annual Technical Conference and Exhibition, Las Vegas, Nevada, USA, September 22-25, 1985.

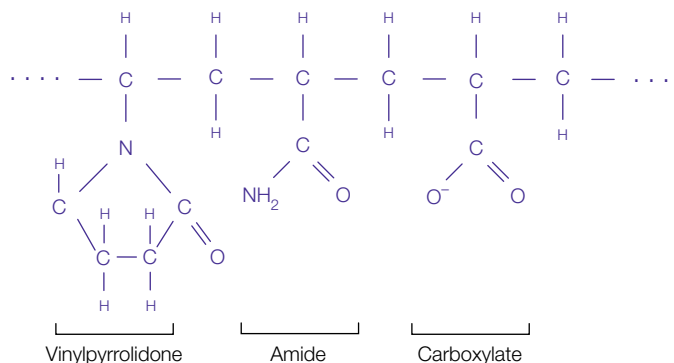
linking.<sup>11</sup> One solution is to use synthetic polymers in which some amide groups are replaced by a more inert chemistry that cannot hydrolyze to carboxylate and therefore remain vulnerable to wandering divalent cations (right).

Part of the Eniricerche effort is directed toward improving the temperature rating of polymer gel systems. Chemical process always speeds up with elevated temperature, and this makes gelling increasingly difficult to control. The most interesting result to date in improving gelation control at high temperature is through use of chromium malonate, yet another metal-carboxylate complex, as cross-linker.<sup>12</sup> Malonate, which has two carboxylic groups as opposed to the single group in acetate or citrate, appears to extend gelation time by an order of magnitude (below). As a bonus, surplus malonate uncomplexed with chromium seems to retard gelation even more and also scavenges those divalent cations such as  $\text{Ca}^{2+}$  that can precipitate the PHPA polymer.

A final challenge in designing polymer gels is ensuring long-term stability. Most gels run the risk of dehydration, a process called syneresis that causes shrinkage and loss of conformance. But it remains an open question how serious this shrinkage can be, and which gelling system, if any, is least affected. As with many other aspects of gelling systems, syneresis remains an active field of research.



□ **Malonate, suggested as a stable complex with chromium for cross-linking, also acts as a calcium divalent cation scavenger.**



□ **An example of a polymer that may be more resistant to divalent cation attack than PHPA. Called poly/vinylpyrrolidone-acrylamide, this polymer gains stability from the inert pyrrolidone groups that substitute for the regular amide or carboxylate groups usually found on PHPA.**

### Treatment Fluid Placement

After chemistry, the second major hurdle in conformance control is placement of treatment fluid. This shifts attention from the chemist to the reservoir engineer who must ask and be able to answer some tough questions: Given a reasonably functional polymer-gel system, what factors determine whether a reservoir will benefit from treatment? And if a reservoir seems a good candidate, how should the treatment proceed? Via producers or injectors? And using some kind of zone isolation or none? Candidate selection is how the reservoir engineer's challenge is paraphrased.

The three-year Department of Energy project at the New Mexico Institute of Mining and Technology has directed attention to most of these questions, and some guidelines have emerged.<sup>8</sup> For example, if the treatment fluid is pumped into injection wells—which according to numerous case studies seem to give better results than producers—theoretical studies show that zone isolation is mandatory when attempting to inject gel into matrix rock porosity but not important when filling fracture porosity.<sup>13</sup> This is because if a matrix reservoir is filled with gel in the wrong places, there is literally no conduit remaining for production. However, in a fractured reservoir where gel fills the fractures, the matrix rock still remains for producing oil.

Ultimately, computer simulation can be invoked to test whether a proposed treatment is likely to work. But this requires more than simulation of reservoir fluid flow. Also needed is a chemical simulator that models how the gelling system reacts with

11. Doe PH, Moradi-Araghi A, Shaw JE and Stahl GA: "Development and Evaluation of EOR Polymers Suitable for Hostile Environments: Copolymers of Vinylpyrrolidone and Acrylamide," paper SPE 14233, presented at the 60th SPE Annual Technical Conference and Exhibition, Las Vegas, Nevada, USA, September 22-25, 1985.

Moradi-Araghi A, Cleveland DH and Westerman IJ: "Development and Evaluation of EOR Polymers Suitable for Hostile Environments: II—Copolymers of Acrylamide and Sodium AMPS," paper SPE 16273, presented at the SPE International Symposium on Oilfield Chemistry, San Antonio, Texas, USA, February 4-6, 1987.

Albonico P and Lockhart TP: "Divalent Ion-Resistant Polymer Gels for High-Temperature Applications: Syneresis Inhibiting Additives," paper SPE 25220, presented at the SPE International Symposium on Oilfield Chemistry, New Orleans, Louisiana, USA, March 2-5, 1993.

12. Lockhart TP and Albonico P: "A New Gelation Technology for In-Depth Placement of Cr+3/Polymer Gels in High-Temperature Reservoirs," paper SPE 24194, presented at the SPE/DOE Eighth Symposium on Enhanced Oil Recovery, Tulsa, Oklahoma, USA, April 22-24, 1992.

13. Seright RS: "Placement of Gels to Modify Injection Profiles," paper SPE/DOE 17332, presented at the SPE/DOE Enhanced Oil Recovery Symposium, Tulsa, Oklahoma, USA, April 17-20, 1988.

the reservoir environment and how gelling constituents react with each other. As reported earlier, BP Exploration performed such a computer simulation in its planning for treating the Kuparuk field with a PHPA-aluminum citrate system. Another fluid-flow/chemical simulator, called SCORPIO, is offered by AEA Petroleum Services, which is based in Dorchester, England.<sup>14</sup> This simulator is currently being used to investigate the feasibility of polymer-gel conformance control in several North Sea fields.<sup>15</sup>

The prudent operator, of course, will temper sophisticated modeling with a good dose of common sense. In addition, it does not hurt to have enough injection and production data available to fully comprehend how the reservoir will react if prodded. Surprisingly, reservoir production data can be sparse and poorly documented. Frequently, production data are known for groups of wells tied to a common pipeline and not for individual wells. However, this was not the case in the Wertz field in Wyoming, USA for which Amoco Production Co. began contemplating a series of conformance control treatments in mid-1991 (*below*).<sup>16</sup>

### Case Study

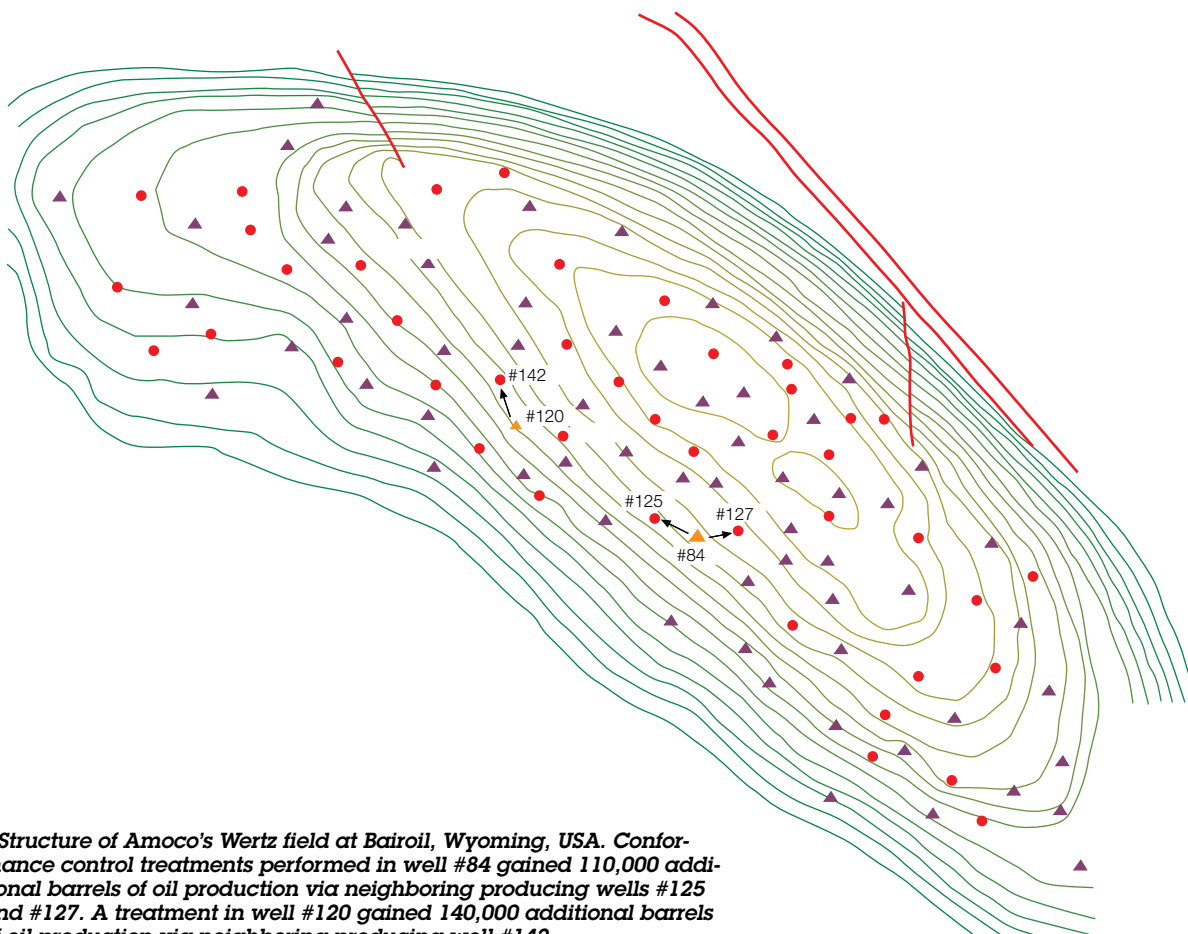
The Wertz field was a model implementation of a CO<sub>2</sub> tertiary flood, and, as a result, field performance had been copiously documented. Not only were individual producers and injectors monitored daily, but flow rates of the three phases present—oil, water and CO<sub>2</sub>—were also measured. These measurements were made in special substations, one substation for every dozen wells or so, each with elaborate and automatic apparatuses for sampling each well's flow in or out and the flow's breakdown into three phases.

The Wertz producing formation is a 470-ft [143-m] thick aeolian sandstone at an average depth of 6200 ft [1890 m], with 240 ft [73 m] of net pay having 10% porosity and 13-md permeability. The formation is believed to have some fractures and is oil wet. Sixty-five wells over 1600 acres are used for production and many more than that have been drilled for injection—alternating water and CO<sub>2</sub> injection, commonly referred to as water-alternating-gas (WAG) injection. By mid-1991, the field's fate literally hung in the balance. The field's total production had dropped precipitously to

4000 BOPD from 12,000 BOPD in 1988, a steeper than expected decline during tertiary flooding.

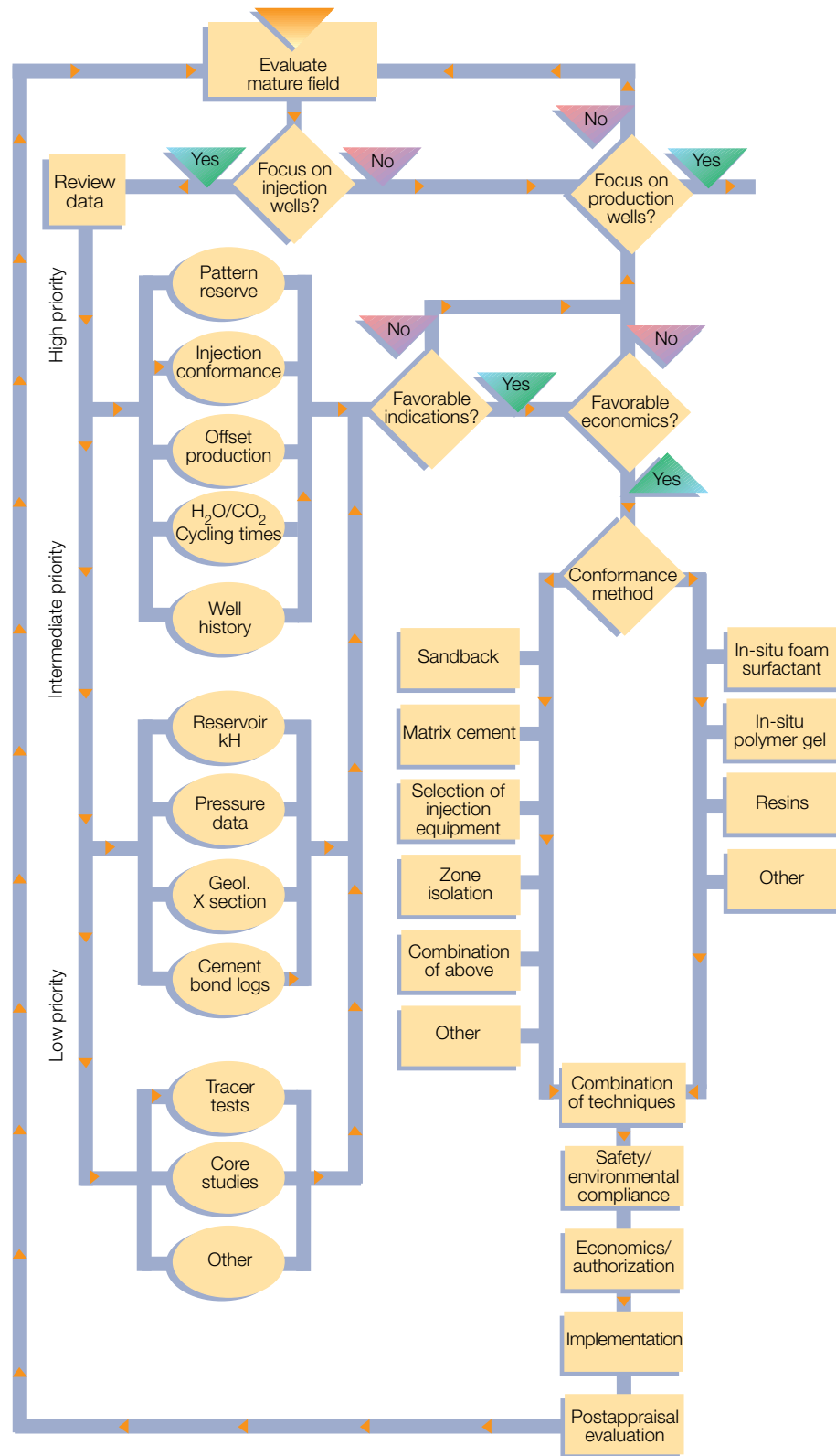
After trying several other techniques to halt the decline, Amoco turned to conformance control, eventually completing 12 treatments using Marathon's polymer gel technology. Ten treatments were in injectors and two in producers. Some treatments were aimed at blocking matrix porosity and some aimed to place gel in reservoir fractures. We'll highlight one example of each, illustrating with injector treatments since these were the more successful. In some cases, the treatments extended the life of a pattern by two years. Overall, Amoco estimates that for a total cost of \$936,000, the treatments have yielded an increase in producible reserves of 735,000 barrels—that is \$1.27 per barrel.

A crucial preliminary step in all these treatments was candidate selection—the compilation and review of data to determine a well's suitability for treatment (*next page*). Although any field information could be relevant, five data types were deemed particularly important. They were:



□ **Structure of Amoco's Wertz field at Bairoll, Wyoming, USA. Conformance control treatments performed in well #84 gained 110,000 additional barrels of oil production via neighboring producing wells #125 and #127. A treatment in well #120 gained 140,000 additional barrels of oil production via neighboring producing well #142.**

- Pattern reserves. If the pattern reserve data indicated that secondary and tertiary flooding had pushed out most of the oil, there was no reason to try further production enhancement with conformance control.
  - Historical fluid-injection conformance. If an injection well historically showed a poor injection profile, the corresponding pattern was obviously a candidate for conformance improvement. In the Wertz field, Amoco used radioactive tracer surveys to log injection profiles.
  - Three-phase offset production data. If producing wells in a pattern showed a cyclic water and CO<sub>2</sub> production that correlated with cycles in the nearby injection well, then it was likely this communication was through an unusually high-permeability channel. The pattern therefore required conformance control.
  - Breakthrough time during the cyclic correlation—essentially the time for water or CO<sub>2</sub> to travel between injector and neighboring producer. This helped estimate the size of treatments designed to fill the fracture space between the wells.
  - Well history information—specifically the history of all previous attempts to improve conformance in the well, and why they did or did not work. This information prevented unnecessary workover expense.
- The first well treated was #84, an injection well on the west flank of the field that fed producers #125 and #127. This well seemed to satisfy the five criteria. An estimated 226,000 barrels of reserves remained in the pattern; injection conformance was poor with no water and very little CO<sub>2</sub> entering the upper part of the well; injection cycling was clearly visible in #125 and #127, with documented breakthrough times of 12 and 14 days, respectively; and previous conformance control attempts with sand had failed because of behind-pipe channeling between the upper and lower parts of the well.
- The well seemed to require a blocking of the high-permeability matrix in the lower

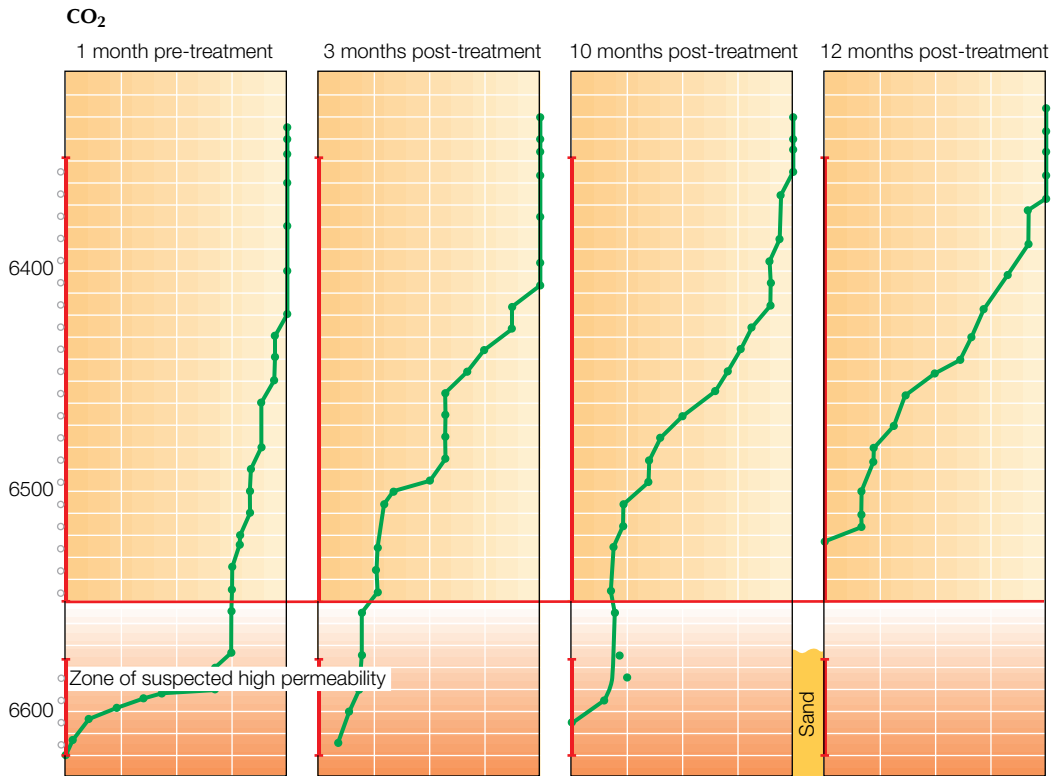
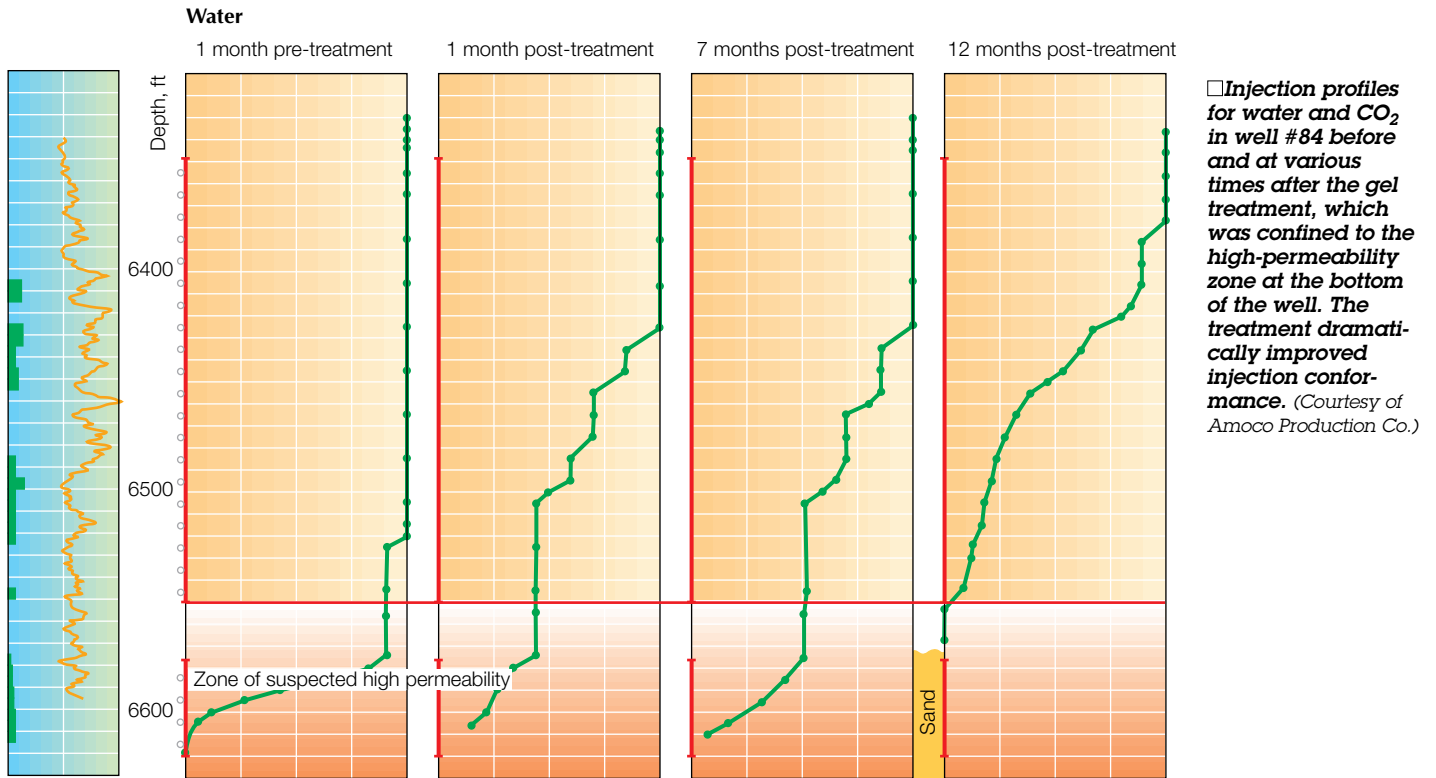


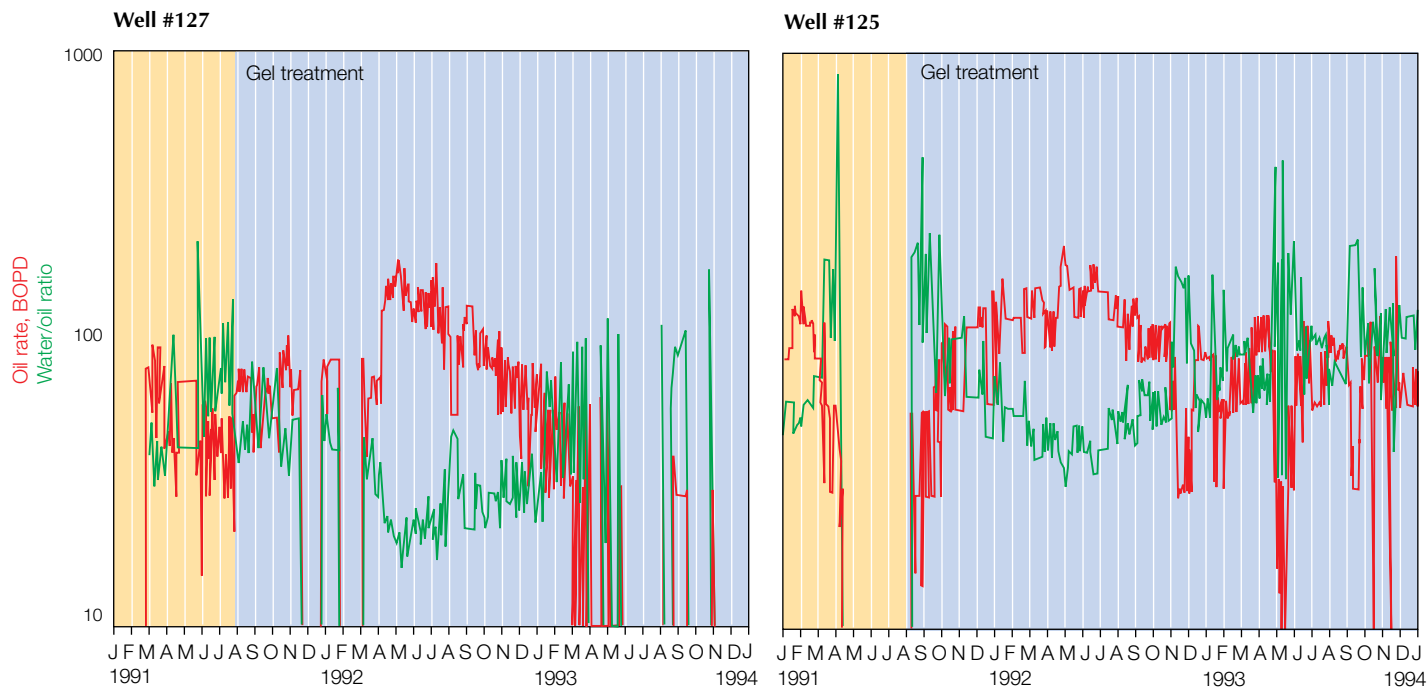
□ Amoco's process logic for picking conformance control candidates in the Wertz field. (Adapted from Borling, reference 16.)

14. Scott T, Sharpe SR, Sorbie KS, Clifford PJ, Roberts LJ, Foulser RWS and Oakes JA: "A General Purpose Chemical Flood Simulator," paper SPE 16029, presented at the 9th SPE Symposium on Reservoir Simulation, San Antonio, Texas, USA, February 1-4, 1987.

15. Hughes DS, Woods CL, Crofts HJ and Dixon RT: "Numerical Simulation of Single-Well Polymer Gel Treatments in Heterogeneous Formations," paper SPE/DOE 20242, presented at the SPE/DOE Seventh Symposium on Enhanced Oil Recovery, Tulsa, Oklahoma, USA, April 22-25, 1990.

16. Borling DC: "Injection Conformance Control Case Histories Using Gels at the Wertz Field CO<sub>2</sub> Tertiary Flood in Wyoming, U.S.A.," paper SPE/DOE 27825, presented at the SPE/DOE Improved Oil Recovery Symposium, Tulsa, Oklahoma, USA, April 17-20, 1994.





□ Improved oil rate and WOR in production wells #125 and #127 for the 30 months following the gel treatment in well #84. The hiccups in early 1992 and mid-1993 in well #127 were caused by surface facilities downtime. (Courtesy of Amoco Production Co.)

zone and also of the behind-pipe channel. Amoco opted for Marathon's low molecular-weight polymer-gel technology, and in addition, mechanically isolated the target interval to avoid losing treatment fluid to the upper zone, a necessary contingency that consumed 55% of the total treatment cost. Altogether, 650 barrels of the PHPA-chromium acetate mixture were pumped at 4 barrels a minute, in a two-stage operation taking one day.

As with all their subsequent conformance control operations, round-the-clock precautions were taken to avoid any environmental contamination by the treatment fluid and to ensure the treatment fluid was being injected in the correct proportions. In addition, fluid issuing from the production wells was monitored to ensure that the treatment fluid did not somehow bypass the matrix and get produced. Finally, samples of the treatment fluid taken in the field confirmed that a rigid gel formed after a few hours.

One month after the treatment, injection conformance in well #84 showed spectacular improvement with 57% of injected water entering the upper zone (*previous page*). Two months later, during a CO<sub>2</sub> cycle, 79% of the CO<sub>2</sub> was entering the upper zone. The situation was just as good after ten months, when Amoco decided to shut off the entire bottom zone with sand. This forced all injection to the upper zone, and

injection profiles thereafter indicated conformance to be practically uniform throughout that zone—a textbook example of injection conformance.

Meanwhile in producing well #125, which had been previously shut in because it produced only water, oil started appearing and production was up to 150 BOPD after twelve months; the water/oil ratio (WOR) decreased to 40 (*above*). Later, oil production began to slip and well #125 was shut in. Nevertheless, the conformance treatment prolonged the life of this producing well by 30 months, furnishing an additional 80,000 barrels of oil.

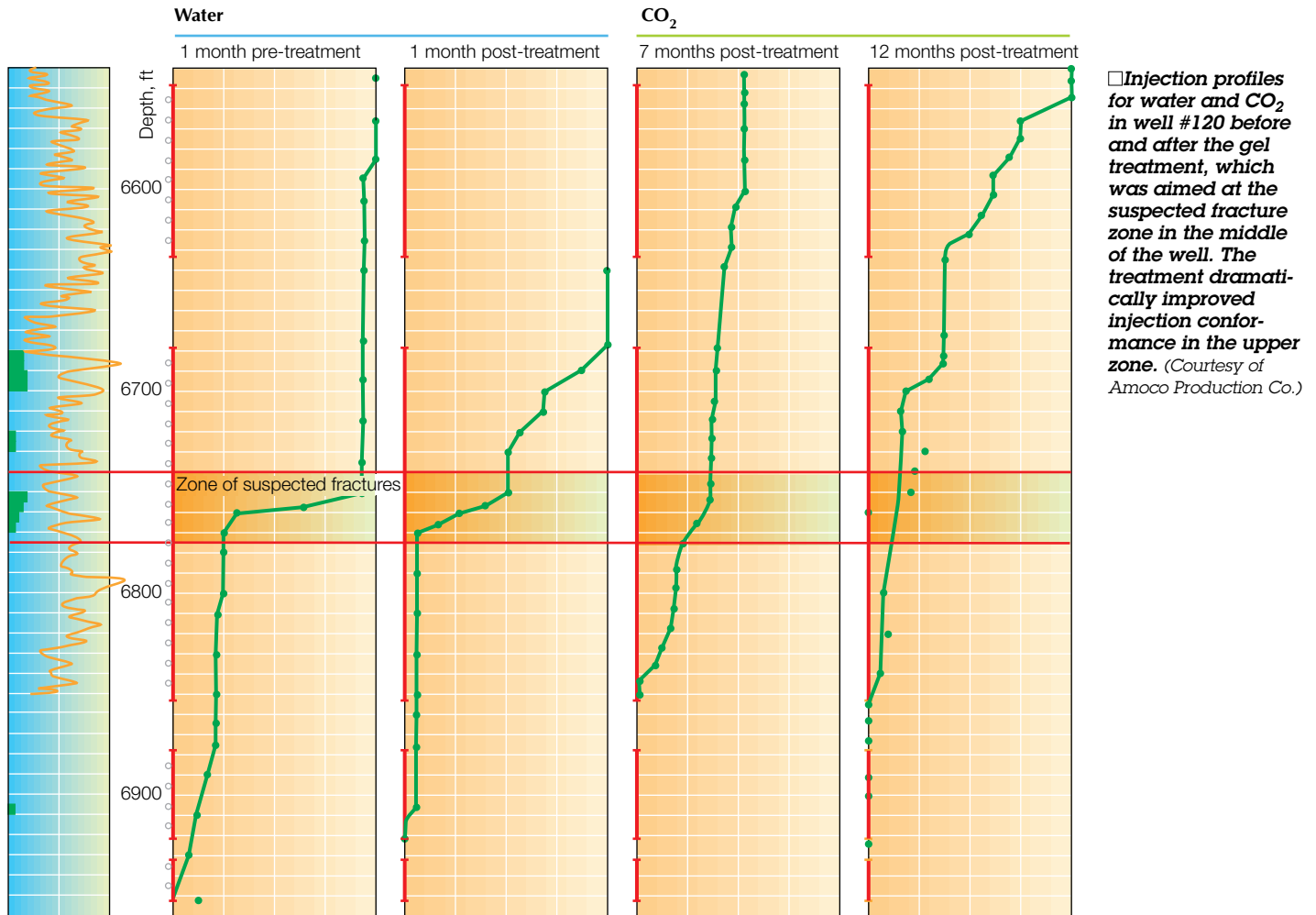
In producing well #127, oil production rose from 45 BOPD before the treatment to 150 BOPD after. During the same time, WOR dropped from 80 to nearly 20. The improvement lasted 30 months, five of which were unfortunately interrupted by facility breakdowns. Altogether, the well produced an extra 30,000 barrels of producible reserves.

The first treatment Amoco performed with large volumes of a high-molecular weight polymer-gel system was in well #120. This well appeared to be in direct communication via fractures with neighboring producer #142, as evidenced by a very rapid one- to three-day breakthrough time for CO<sub>2</sub> injection. Corroborating a rapid communication between the wells was the behavior of well #142. It could produce oil when #120 was shut in, but its performance would deteriorate

as soon as #120 started injecting. Other factors favoring a gel treatment for #120 included an estimated 209,000 barrels of missed reserves, poor injection conformance with nearly 90% of the water entering a suspected mid-pay fracture, and a well history showing that earlier treatments using in-situ surfactant foam had failed to improve conformance.

The treatment in #120 was altogether of a different scope than the matrix treatment in #84. First, treatment volume totaled 10,000 barrels and took seven days to pump, at the rate of one barrel per minute. This volume was estimated to be enough to completely fill the fractures between the two wells. Second, no mechanical isolation was used because the treatment fluid was expected to be able to enter only the targeted fractures. After waiting a few days to let the system gel, well #120 was once again put on alternating water and CO<sub>2</sub> injection. As measured by tracer surveys, the conformance for both fluids was significantly improved (*next page, top*).

Production at #142 still responded to the water-CO<sub>2</sub> cycling, indicating that the gel had not completely filled the fracture system and that therefore some communication remained, but oil rate improved, reaching 275 BOPD more than it would have with-



out treatment. WOR dropped to 30 where it remained for more than two years (right). Altogether, the treatment prized out of the tired reservoir an additional 140,000 barrels of oil.

Amoco's strategy in the Wertz field never included sophisticated computer simulation to pick conformance candidates. Rather, it relied on unusually complete field documentation and a well thought-out, methodical approach for candidate selection. In a small, well understood field, Amoco succeeded in making conformance control an economic success. The next years will see whether this success can be extended to larger fields—in the Alaskan North Slope, the UK and the Middle East, for example—that are entering their twilight years and where the economics are on a significantly larger scale.

Meanwhile, the chemists remain at their desks, fine-tuning their understanding of gelling, seeking a better polymer, and moving out to new systems such as polymer-gel foams. Conformance control is here for the duration as long as oil fields continue to produce water. —HE

