Polymer-specific enzyme breaker improves completion efficiency in horizontal wells


*melgassier@bjservices.com

Bottom line. Phillips Alaska Inc. realized a 400-bopd incremental production increase in Well 3K-24, a horizontal well with slotted liner, by using polymer-specific enzymes (PSE) to reduce polymer-related, drill-in fluid damage. Respective contributions from lowering of skin and increased production efficiency of the lateral length were 150 bopd and 250 bopd.

Field description. Kuparuk Field, which is located on the North Slope of Alaska, began producing in 1984. The Kuparuk River formation is made up of Upper and Lower Members separated by a regional unconformity. The five A sands are of Lower Cretaceous age. The sands are overlapping, trending from northwest to southeast. Thicknesses of the sands range up to 80 ft, extending along strike up to 40 mi, and down dip up to 15 mi. Sand porosity ranges from 0.2 to 30% and permeability ranges from 25 to 50 md. Water saturation is about 25%.

The formation depth is approximately 7,000 ft. Reservoir temperature is 170°F. Oil in the fault block has an API gravity of 21.3° and a viscosity of 0.8 to 1.2 cp. Asphaltene content is 8%.

In the A sands, the primary cementing materials are clays supplemented by additional cementation that results from compaction of authigenic quartz overgrowths on the matrix.

Fig. 1. Final return permeability after the acid soak was 96% for the lab mud and 83% for the field mud. Treatment was an enzyme soak, followed by an 8% formic acid soak.

Permeability after formic acid wash and soak, 81md
Permeability after mudzyme, 73md
Permeability after leak-off, 11md

New Dominion, L.L.C. has taken a bolder approach to developing major new reserves in exhausted oil and gas fields. see page 4

Nitrogen huff and puff process breathes new life into old field

Using a nitrogen huff and puff (cyclic) process, Breton G. P. increased production from a mature Appalachian basin reservoir from 200 bopd to 500 bopd with no significant increase in water production. see page 6

Air pulse system for artificial lift reduces costs

In six months of testing at the Rocky Mountain Oilfield Testing Center (RMOTC), a unique air pulse lifting system, developed by Petroleum Asset Management Co. (PAMCO), lowered power consumption for lifting fluids in two shallow oil wells by 71%. see page 9

Company-operated, integrated, E&P waste management facility reduces costs

An integrated, E&P waste management facility has reduced Patina Oil & Gas Corp.’s costs for processing oil-contaminated soils and fluids, including tank bottoms. see page 11

Reliable, low cost vapor recovery system saves money while helping the environment

Since 1994, Devon Energy Corp. has employed the Vapor Jet system to capture hydrocarbon vapors from oil and water storage tanks in a West Texas waterflood operation. see page 12

Pilot test demonstrates how CO2 injection enhances coalbed methane recovery

Since 1995, Burlington Resources has been conducting a pilot test of enhancing coalbed methane recovery through carbon dioxide (CO2) injection. see page 14

®

September 2000 Petroleum Technology Digest 1
grains. The intergranular porosity is very good. Permeability is relatively good, primarily because of abundance of open intergranular pores, good conductivity and generally low amounts of pore-occluding authigenic mineral precipitates. The illitic clays are grain-coating and poorly-formed/cemented to the matrix grains, which makes the formation susceptible to fines migration. Polymers are required in drill-in fluids to provide a quality completion.

The problem. Polymers in drill-in fluids invade the near wellbore formation and form filter cake around the wellbore. This can substantially reduce well productivity, especially in horizontal and multilateral wells. Conventional clean-up methods, mainly oxidizers and acid treatments, have limited success in removing the damage caused by polymer residue. These chemical agents—bleach (sodium hypochlorite), lithium hypochlorite, persulfates and acids—react with polymers regardless of the cleavage site location. Therefore, they may react with any available site on a polymer chain or, for that matter, with downhole tools and tubular goods. This significantly reduces the chance of efficient degradation of the polymer strand.

Furthermore, these agents react with a maximum of two sites per molecule, which causes the agents to spend quickly, especially at elevated downhole temperatures. The end result of this is a partially degraded polymer fragment. These fragments can clog pore throats and slotted liners. These oxidizers and acids also can be incompatible with formation minerals, producing undesirable side reactions with reservoir fluids. They also can cause corrosion in tubulars.

Polymer-specific enzymes (PSE). Enzymes are large, highly specialized proteins that are produced by living cells. They are present in all biological systems and are derived from all-natural systems. Although enzymes are not living organisms themselves, they act as catalysts to accelerate chemical reactions, therefore, they have the unique ability to remain unchanged and available to promote other reactions for an essentially indefinite amount of time.

Advancements in biotechnology have led to the isolation, purification and fermentation of PSE complexes to remove the residual polymer damage associated with starch-, xanthan- and cellulose-based polymers used in the drill-in process. Each PSE system has been optimized to improve hydrolysis of specific polymeric linkage sites along the targeted polymer chain. Degradation of polymer molecules occurs as the enzyme cleaves the polymer along its binding sites, ideally reducing it to simple sugars. These sugars are of low molecular weight, water soluble and easily flow through the pore matrix along with produced fluids.

Three horizontal completions. Three wells (3K-22, 3K-23, 3K-24) were designed as horizontal completions with slotted liners. The wells targeted two vertically separated sands, A2 and A3. Completion details for each well are listed in Table 1.

Prior lab and pressure transient tests confirmed that permeability damage—as a direct result of filter cake deposits on the formation face from a dual-polymer drill-in fluid system—would be a problem. Several conventional return permeability tests were run to evaluate filter cake removal methods using lab-prepared and actual field samples of the drill-in fluid in conjunction with Kuparuk field A sand core samples.
Cleanup treatments were evaluated on lab and field mud samples. Results using field mud are illustrated in Fig. 1. This treatment was an enzyme soak, followed by an 8% formic acid soak designed to remove the calcium carbonate bridging material. The final return permeability after the acid soak was 96% for the lab mud and 83% for the field mud.

**Field results.** Well 3K-22 was drilled first using a fresh-water, low-solids, nondispersed mud system. Barite was added to control density. No xanthan-type drill-in fluid was used, since the well was completed with a cemented perforated liner. The well was put on production for six months and then converted to an injector.

Wells 3K-23 and 3K-24 were completed as horizontal producers with slotted-liner completions. The horizontal sections were drilled with a 6% KCl-brine-based, dual-polymer drill-in fluid consisting of starch and xanthan. Sized calcium carbonate was added to help provide additional leak-off control.

For 3K-24, a PSE treatment was designed to remove the majority of the drilling fluid filter cake from the horizontal pay-zone sections. The treatment was pumped after running the 4½-in. slotted liner to TD. The wellbore clean up was done using an inner wash string to circulate the treatment into the 4½-in. slotted liner by openhole annulus. A buffer was used to avoid drill-in fluid contact with the mudzone. There were no well control problems after placing the treatment, as it does not act on the calcium carbonate bridging agents. The well was then put on production.

Completion efficiency results for the three wells are summarized in Table 2. The 3K-24 completion has the best completion efficiency at 96%.

This increased efficiency is attributed to proper design of the drill-in fluid and the PSE cleanup operation. Completion efficiency represents the well's production relative to the potential rate with a zero-skin completion. The estimated rate increase associated with the 3K-24 completion program is 400 bopd. Of this, 150 bopd is attributed to lowering skin, while 250 bopd is attributed to increased production efficiency of the lateral. The daily rates are an average rate over the first three months of production.

**ACKNOWLEDGMENT**
This case study was summarized from SPE paper 58732 presented at the 2000 SPE International Symposium on Formation Damage held in Lafayette, La., 23–24 February 2000. The authors wish to thank Phillips Petroleum Alaska, Inc. (formerly ARCO Alaska, Inc.), BP Exploration (Alaska) Inc., the Kuparuk River Unit co-owners and the management of BJ Services Co. for permission to publish this case study.

**The Authors**
- **Dr. Albert Chan** is a research scientist for Phillips Petroleum Co. (formerly AEPT) in Plano, Texas. He holds a PhD degree in chemistry from Rice University.
- **Drew Hembling** is a staff petroleum engineer with Phillips Alaska, Inc. (formerly Arco Alaska, Inc.) in Anchorage, Alaska. He holds a BS degree in petroleum engineering from West Virginia University.
- **Brian Beall** is a Senior research engineer with BJ Services (Sand Control/Well Completions) in Tomball, Texas. He holds a BS degree in petroleum engineering from the University of Texas at Austin and has authored and co-authored various papers on using enzymes to clean up drill-in fluid filter cake.
- **Dr. Mokhtar Elgassier** is a technical consultant with BJ Services (reservoir engineer) in Anchorage, Alaska. He has authored and co-authored numerous industry technical papers focusing on formation damage and well stimulation. He majored in geology at Colorado State University.

**J. Jay Garner** is employed by BJ Services Company in Anchorage, Alaska. He has authored and co-authored numerous industry technical papers focusing on formation damage and well stimulation. He majored in geology at Colorado State University.

---

### Table 1. Well completion details

<table>
<thead>
<tr>
<th>Type</th>
<th>3K-22 Producer/Injector</th>
<th>3K-23 Producer</th>
<th>3K-24 Producer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Casing size, in.</td>
<td>7%</td>
<td>7%</td>
<td>7%</td>
</tr>
<tr>
<td>Tubing size, in.</td>
<td>4½</td>
<td>4½</td>
<td>4½</td>
</tr>
<tr>
<td>Liner size, in.</td>
<td>4½</td>
<td>4½</td>
<td>4½</td>
</tr>
<tr>
<td>Perforated interval, ft</td>
<td>1,800</td>
<td>1,450</td>
<td>2,300</td>
</tr>
<tr>
<td>Shots per ft</td>
<td>4</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>Net A3 sand, ft</td>
<td>830</td>
<td>1,135</td>
<td>2,189</td>
</tr>
<tr>
<td>Net A2 sand, ft</td>
<td>420</td>
<td>1,427</td>
<td>3,023</td>
</tr>
<tr>
<td>Average net pay thickness, ft</td>
<td>13</td>
<td>31</td>
<td>34</td>
</tr>
</tbody>
</table>

### Table 2. Completion efficiency and summary data

<table>
<thead>
<tr>
<th>Length of Horizontal section, ft</th>
<th>3K-22</th>
<th>3K-23</th>
<th>3K-24</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pay, ft</td>
<td>1,400</td>
<td>1,450</td>
<td>2,300</td>
</tr>
<tr>
<td>K, md</td>
<td>29</td>
<td>25</td>
<td>60</td>
</tr>
<tr>
<td>Kv/Kh</td>
<td>0.053</td>
<td>0.092</td>
<td>0.010</td>
</tr>
<tr>
<td>Leff, % effective</td>
<td>86</td>
<td>89</td>
<td>100</td>
</tr>
<tr>
<td>producing length from net pay within the horizontal section)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Skin</td>
<td>1.15</td>
<td>1.3</td>
<td>0.40</td>
</tr>
<tr>
<td>Completion efficiency,%</td>
<td>77</td>
<td>81</td>
<td>96</td>
</tr>
</tbody>
</table>

---

**Major reserve increase obtained by dewatering high-water-saturation reservoirs**

David Chernicky, New Dominion, L.L.C., Tulsa, Okla.

**Bottom line.** New Dominion, L.L.C. has taken a bolder approach to developing major new reserves in exhausted oil and gas fields. By applying technology now accepted in coalbed methane production to very extensive, high-water-saturation oil and gas fields, reserves previously considered uneconomic have become profitable.

**Background.** From its beginning in 1998, New Dominion, L.L.C. (NDL) has been focused on producing high-water-saturation reservoirs, such as the Hunton limestone in central Oklahoma. The Hunton is quite heterogeneous, producing by partial water drive. Except for selected wells on structural highs, wells encounter thick, but typically high-water-saturation zones. Wells in this environment had been conventionally produced and typically abandoned, or bypassed entirely, because of high water production and the economic factors associated with the same.

However, New Dominion’s experience has proven that systematic dewatering of the entire reservoir, not just individual wells, results in synergistic interaction among wells, leading to decreasing water:oil ratio (WOR) as field development occurs. Development of new reserves in this environment requires the following six essential components:

- Correct geological assessment of the reservoir
- Abundant and economic high-current, three-phase electrical power
- A high-volume gas gathering and processing system, which is often nonexistent in the areas around these types of reservoirs.
- An extensive and economic high-volume produced water disposal system
- A large front-end capital investment to assure that enough wells are drilled in the initial phase to effect the synergistic interaction among the wells, which causes the producing water:oil ratio (WOR) to decrease markedly as field development continues.

---

**Dr. Mokhtar Elgassier:**

Dr. Mokhtar Elgassier is a technical consultant with BJ Services (reservoir engineer) in Anchorage, Alaska. He has authored and co-authored numerous industry technical papers focusing on formation damage and well stimulation. He majored in geology at Colorado State University.

---

**J. Jay Garner:**

J. Jay Garner is employed by BJ Services Company in Anchorage, Alaska. He has authored and co-authored numerous industry technical papers focusing on formation damage and well stimulation. He majored in geology at Colorado State University.

---

**The Authors:**

- **Dr. Albert Chan** is a research scientist for Phillips Petroleum Co. (formerly AEPT) in Plano, Texas. He holds a PhD degree in chemistry from Rice University.
- **Drew Hembling** is a staff petroleum engineer with Phillips Alaska, Inc. (formerly Arco Alaska, Inc.) in Anchorage, Alaska. He holds a BS degree in petroleum engineering from West Virginia University.
- **Brian Beall** is a Senior research engineer with BJ Services (Sand Control/Well Completions) in Tomball, Texas. He holds a BS degree in petroleum engineering from the University of Texas at Austin and has authored and co-authored various papers on using enzymes to clean up drill-in fluid filter cake.
- **Dr. Mokhtar Elgassier** is a technical consultant with BJ Services (reservoir engineer) in Anchorage, Alaska. He has authored and co-authored numerous industry technical papers focusing on formation damage and well stimulation. He majored in geology at Colorado State University.

---

**J. Jay Garner:**

J. Jay Garner is employed by BJ Services Company in Anchorage, Alaska. He has authored and co-authored numerous industry technical papers focusing on formation damage and well stimulation. He majored in geology at Colorado State University.
A well-trained and knowledgeable field staff to safely maintain a highly loaded and challenged mechanical system.

NDL installs all of the electrical, production water, gas and even oil distribution and collection infrastructure in advance of drilling production wells, which can produce up to 6,000 bfpd per well. Once initial production is established, NDL begins an intensive and systematic development drilling program to systematically dewater and produce the entire reservoir.

Identifying the reservoir. Fig. 1 depicts a portion of a field NDL developed in Lincoln County, Okla. This small area (4,800 acres) had experienced sporadic drilling over 30 years, which resulted in 31 penetrations of the Hunton limestone. Conventional production methods before New Dominion’s efforts had yielded only 37,552 bbl of oil and 482,901 Mcf of gas.

The operator re-analyzed the well data and, in less than two years, drilled or re-entered 28 new Hunton producers, thus developing proven recoverable reserves of 2.2 million bbl of oil and 16.2 Bcf of gas. The field is still undergoing development and total reserves are expected to increase.

Characteristic production. Production data for 28 wells through April 2000 is illustrated in Fig. 2. This field exhibited a relatively fast response time to dewatering efforts, as shown in this composite curve. The increase in oil cut (decrease in WOR) is evidenced by the convergence of the two individual curves. Gas volumes produced are quite extraordinary—nearly 14 MMcfd.

Within 16 months, this well was producing less than 600 bwpd and was placed on beam pump. Oil production increased to over 80 bopd, and gas production was in excess of 500 Mcfd. Initial WOR was 160:1, yet in only 16 months, the ratio had declined to 7.5:1, a 21-fold decrease. Well spacing was one well per 160 acres at this time, though the operator has recently increased well density to maximize recovery and present value of the investment.

New Dominion’s staff has been developing these types of reservoirs for more than 17 years, providing them with insights on the physical processes at work and a wealth of practical operating experience. The company is working with two of Oklahoma’s major universities to better understand the reservoir processes at work with the goal of extending the technology application to other appropriate oil reservoirs.

Wells and facilities. Unconventional production techniques require different production technology and expertise, both downhole and on the surface. Anticipating high fluid and gas volumes, 8 3⁄4-in. holes are drilled through the Hunton at depths ranging from 4,900 to 5,100 ft. Seven-in. casing is set and cemented 300 ft or more above the Hunton.
Standard, triple-combo openhole logging suites (Dual Focused Induction, Compensated Neutron Density with PE and Microlog) are used to interpret reservoir quality.

“Dry holes” are rare, since adequate well data to define the reservoir exists prior to drilling. Production casing is always on location at the time of logging. The entire zone is perforated at one shot per foot and treated with an acid/water frac (sand is used as a diversion agent). Good reservoir rock requires less stimulation than poor reservoir rock, just as in conventional production methods.

To facilitate large fluid and gas volumes, 3½-in. tubing is utilized. Typically, electric submersible pumps with dynamic operating ranges of 1,500 to 4,000 bfpd are installed. The horsepower of these pumps ranges from 100–250 hp. Wells are equipped, and offset wells drilled, in such a manner as to affect a 30 to 40% decrease in pumping bottomhole pressure within a reasonable amount of time.

One of the greatest problems is the large quantity of gas produced with the oil-water mixture. Gas volumes can exceed 2 MMcfd per well and, with fluid rates in excess of 3,000 bwpd and 100 bopd, many complications, such as foaming, flowline restriction and fluid phase carry-over keep the field staff running at all times. Gas-fluid separation is accomplished with specially designed and fabricated high-volume, high-pressure gas separators placed at the wellhead and/or at the central production facility.

Fluid phase (oil/water) separation is accomplished by specially designed and fabricated horizontal free water knockouts (FWKO). Chemical treatment is applied at the separation facility to accelerate and increase separation efficiency.

There is no room for “poor boy” production techniques or equipment in this type of operation. All equipment is run at 100% load. Run time for new submersible pumps and tubing strings exceeds three years, but the fluid volumes usually decrease sooner, necessitating a pump change to either a smaller submersible pump or a beam pump.

An operator must have total commitment to this type of operation to consistently utilize the downsized equipment inventory. Sometimes, when working around older fields, which may have experienced fluid injection, for either secondary recovery or for direct disposal use, H₂S is encountered, and significant safety and costly chemical treatment programs must be implemented.

Produced-water disposal facilities. High-capacity and efficient produced-water disposal wells are critical to this type of production operation and cost about $500,000 each. Typically, a 10¼-in. hole is drilled to the top of the Arbuckle limestone at 5,800 ft (800 ft below the Hunton). After running and cementing 9½-in. casing, the entire Arbuckle column is drilled and completed open hole (2,000 ft). Then, 7-in. lined-casing is set as a tubing string and the well is capable of taking 15,000–20,000 bwpd on vacuum and in excess of 25,000 bwpd if equipped with a high-volume, low-pressure centrifugal pump necessary to overcome line friction in the tubing string.

Produced water disposal well sites are selected in advance throughout the field. The number of wells needed to dewater one field depends upon:

- Individual quality and capacity of each disposal well
- Average initial fluid volume per each producing well
- Rate of field development.

A continual review of progress is required to optimize utilization of disposal facilities and maximize return on investment.

Safety. The large volume of produced water mandates 24-hour monitoring of facilities and producing wells. Extensive electronic safety and...
Nitrogen huff and puff process breathes new life into old field


* bernie.bretagne@hotoffice.net
**rgaudin@mymailstation.com

Bottom line. Using a nitrogen huff and puff (cyclic) process, Bretagne G. P. increased production from a mature Appalachian basin reservoir from 200 bopd to 500 bopd with no significant increase in water production. Cumulative recovery through May 2000 is 115,000 bbl of oil from cumulative injection of 342 MMcf of nitrogen. The composite projected nitrogen utilization factor for the project is 1.2 Mcf per incremental bbl from the initial 163 wells treated.

Huff and puff (cyclic) process. Conventional huff and puff applications have concentrated on using a solvent (such as steam or carbon dioxide). Applications often are limited by two factors—economic availability of the primary injectant and the mechanisms of the huff and puff process itself. This patent-pending huff and puff (cyclic) process using nitrogen addresses both concerns.

Compact nitrogen membrane units (Fig. 1), currently used for onshore and offshore operations and in other industries, can provide nitrogen gas to oil fields at economical costs. From a displacement standpoint, this process also takes advantage of nitrogen’s unique characteristics, which allow natural gas to bypass and not be absorbed during the huff phase, and then to take the place of and displace oil and gas during the puff phase. The application is especially targeted for dual-porosity reservoirs where classic displacement mechanisms are non-commercial. From an operations standpoint, nitrogen is user-friendly in that it is inert, non-corrosive and environmentally friendly.

The huff and puff (cyclic) process is a single well process involving three basic phases:

- The huff phase—injectant is introduced into the well’s drainage area
- Shut-in phase—injectant is allowed to dissipate into reservoir to an optimum equilibrium
- Puff phase—some of the injectant is left in place and hydrocarbons are produced.

If the process is performed at above fracture pressures or if the injectant reacts with the formation, then stimulation of the reservoir rock can take place.

During the huff phase—since nitrogen does not dissolve in the reservoir fluids or dissipate, as is the case with carbon dioxide and steam—the gas is able to penetrate further into the reservoir. In the case of a fractured reservoir, the nitrogen can penetrate easier into the rock matrix.

In the conventional displacement process, the injectant goes into the matrix or fault blocks, but is trapped and cannot be easily produced. With depletion, the matrix has voidage that the nitrogen can occupy and then become trapped. Since nitrogen is a gas, the nitrogen occupies less space in the huff phase under higher pressure than in the puff phase, where the pressure has been significantly decreased.

These basic processes, along with the relative permeability changes and gas trapping, can result in significant oil recovery. While in most cases additional oil recovery can be obtained by huff and puff with nitrogen gas, the efficiency of the recovery process is dependent upon the composite of reservoir characteristics and the procedure used.

Big Andy project. Production from the Big Andy project in Lee County, Ky., is from a shallow (1,300-ft) reservoir with an average thickness of 40 ft. The reservoir is known to be a dual porosity or fractured reservoir system. Prior to the project, depletion from primary production had lowered the reservoir pressure to an average of 25 to 50 psi. Production from the 400-well project was only 200 bopd, averaging about 0.5 bopd/well. The low reservoir pressure and presence of natural fracturing facilitated gas injection during the huff phase. Nitrogen could be injected easily at 150 psi. At this design pressure, lower-cost polypropylene line systems could be used to deliver the nitrogen to the wells.

The initial nitrogen membrane unit was installed and started in July 1998 to deliver 350 Mcfd of 5% oxygen and 95% nitrogen. As experience was gained and the treating program expanded, volume was increased to 750 Mcfd within the next year. Nitrogen purity, targeted at 95%, can range from 93 to 95%. Adverse effects of lower purity (higher oxygen) nitrogen vary, depending upon the sensitivity of brine and other constituents to higher oxygen levels.

Nitrogen is injected down the annulus of producing wells. Individual well injection rates vary from 20 to 100 Mcfd, depending upon the stage of injection in the well and the relative permeability to gas, with the average rate during injection being about 50 Mcfd per well. At these rates, about 15 wells are in the huff phase at any one time in time.

Compact nitrogen membrane units (Fig. 1), currently used for onshore and offshore operations, provide nitrogen gas to oil fields at economical costs.

* Bernie Miller, an independent production consultant. He worked with Marathon Oil and Amoco Production in the Rocky Mountain region before beginning an independent practice in Oklahoma in 1983.

** Robert Gaudin, an owner, director of exploration and manages New Dominion, L.L.C.’s Tulsa office. A graduate of the University of Oklahoma with a degree in exploration geophysics, he worked with Marathon Oil and Amoco Production in the Rocky Mountain region before beginning an independent practice in Oklahoma in 1983.
To date, most producers are in the first cycle. The typical initial cycle consists of injecting about 1.0 MMcf of nitrogen, a shut-in period of about 30 days, and then the well is returned to production.

Cycle interval depends upon many factors. The overriding consideration is that recovery per cycle will overlap; thus, oil recovery is not believed lost by retreating prior to production returning to the base line. Thus, the interval is dependent upon the optimization of the resources available, including, but not limited to:

- Optimum treatment size per cycle
- Optimum shut-in time
- Optimum available injection-gas volume and pressure
- Treatment cost (including the lost production during huff and shut-in periods).

Production response to two cycles on the Noah Little lease is illustrated in Fig. 2. The first cycle used 860 Mcf per well, and has a projected incremental recovery of 1.7 Mcf per incremental bbl over base production. The second cycle used 570 Mcf per well and has a projected recovery of 1.4 Mcf per incremental bbl over first-cycle projected production.

Through May 2000, oil production has increased from 200 bopd with a 40% decline rate to 500 bopd, and it is still increasing, Fig. 3. With the increase in gas production, part of the casing head gas is being gathered and compressed for use as fuel, stripped of liquids and recycled. Further gas processing is being evaluated on a stand-alone basis. Expectations are that overall recovery may be increased 10 to 20% by recovering the liquids in the produced gas.

Cumulative incremental oil recovery through May 2000 is 115,000 bbl from cumulative nitrogen injection of 342 MMcf—or a nitrogen utilization of about 3 Mcf per incremental bbl. Injection volume includes gas injected into wells currently shut in during injection and in the shut-in periods. Cumulative incremental oil does not include future production from the gas that has been injected. Estimated ultimate nitrogen utilization factor on the first 163 wells is 1.2 Mcf per incremental bbl, ranging from 0.5 to 2.0 Mcf per incremental bbl for individual leases.

Economic data. Nitrogen (95% purity) can be generated using a nitrogen membrane unit for approximately $1.50/Mcf, depending upon cost of electricity, unit size, cost of capital and maintenance cost. Well treatment cost depends upon availability of nitrogen transportation to the wells and the cost of well preparation. In the Big Andy case, a pre-existing oil sales line is being used to distribute nitrogen through the field to the central tank batteries, and the flowlines are reversed during the huff treatment on a lease basis.

The wells are prepared by shutting down the pumping units, and nitrogen is diverted into the casing annulus. Under this system, the composite cost of the nitrogen is about $2.00 per Mcf. Average payout time is 150 days at current oil price ($25/bbl), including well shut-in time for injection and shut-in.

With no increase in water production and no increase in other operating costs, the incremental production goes to the bottom line. Of particular significance, the process can be tested in a given reservoir without a great deal of capital exposure.

ACKNOWLEDGMENT

Case study material has been presented to a local section meeting of SPE in Paintsville, Ky., during February 2000 and an Independent Oil & Gas Association Meeting of New York in June 2000.

THE AUTHOR

Bernie Miller, president of Bretagne G.P in Lexington, Ky., holds a petroleum engineering degree from West Virginia University and an MBA in finance from Tulane University. Prior to Bretagne, he worked the Gulf Coast area with Gulf Oil Corp. and Omni Exploration, Inc. During the last 11 years, he has authored four papers on the huff and puff process.

Robert Gaudin is managing partner of Nitrogen Oil Recovery Systems, L.L.C. in Evansville, Ind. He holds degrees in land management and geology from the State University of New York, Potsdam, NY. He has been managing partner of Mid-Central Land Services, L.L.C. for more than 25 years. Prior to Mid-Central, he was a consultant to the New York state attorney general.
**Air pulse system for artificial lift reduces costs**


*ed.corlew@cybersensor.com*

**Bottom line.** In six months of testing at the Rocky Mountain Oilfield Testing Center (RMOTC), a unique air pulse lifting system, developed by Petroleum Asset Management Co. (PAMCO), lowered power consumption for lifting fluids in two shallow oil wells by 71%. Significantly, there was enough excess capacity with the 3-hp air compressor used during the test to lift similar wells with little incremental operating cost. Remote monitoring and control via satellite and web-based software were effectively demonstrated, potentially eliminating trips to the field.

**Problem addressed.** Operators, particularly those of marginal wells, are searching for ways to lower pumping costs and improve production. Sucker rod pumping systems, although long accepted in the industry, are not without shortcomings. To maintain operational economics, proper design and maintenance are essential. Maintenance costs can be high, particularly in deviated wells subject to rod and tubing wear. PAMCO’s system provides an alternative that, when applied in the appropriate environment, will reduce lifting costs, avoid maintenance costs and, in some cases, actually improve production. The PAMCO system, with only one moving part downhole, has no sucker rods, so pulling costs are virtually eliminated.

**Solution.** The PAMCO system consists of a downhole pump chamber with a one-way ball valve on the bottom, allowing fluid entry, and two lines—one for air/gas inlet and a small return line for producing liquid slugs to the surface. The system is computer-operated and senses filling of the downhole pump chamber. When the chamber is filled, sensors trigger the release of an air/gas pulse. This pulse, typically supplied by a small air compressor, displaces fluid in the pump chamber and lifts the liquid slug to the surface through the return line.

With only one moving part (the inlet ball valve) downhole, maintenance costs are minimal. Operations can be monitored remotely and controlled via satellite through Cybersensor.com, Inc. (a strategic partner) and web-based software. The Cybersensor technology can be accessed from any computer connected to the Internet (using a password) and also provides control of tank gauges, flow meters and other peripheral equipment.

The system does not fit all situations. The optimum application is for wells located relatively close together (so that one compressor can supply air for several wells), depths less than 2,000 ft and fluid volumes less than 100 bpd. It can be applied in oil wells or in marginal gas wells where it helps keep water removed.

**Installation.** Two shallow, 500-ft wells that produce from the Shannon formation were chosen for the test. Well 72-2 was drilled in 1992 and perforated in the Shannon formation from 302–412 ft. Its production had declined to an average of 1 bopd and 9 bwpd. Well 72-41 was drilled in 1989 and perforated in the Shannon formation from 292–402 ft. Its production had declined to an average of 1 bopd and 8 bwpd. Produced oil is 36° API with a high paraffin content. Produced brine has a high scaling index.

A workover rig pulled the rods and tubing from each well, and PAMCO’s pumping system was installed in each well. In this instance, ¾-in. steel tubing was used for the inlet lines and 1-in. PVC for the return lines. A small, 3-hp compressor supplied air for both wells, Fig. 1.

The two wells were tested from October 1999 to May 2000. In both wells, production followed established declines, Fig. 2. The wells were down in March 2000 due to field electrical problems. There were no well pulling costs nor unusual maintenance costs. Paraffin and scale from produced fluids did not cause any operational problems throughout the test.

Remote monitoring and control of the wells were accomplished through a built-in satellite link connected to the wellsite. Proprietary web-based software, with access to the wellsite over the Internet, also was tested effectively. Remote, near-real-time alarm and messaging was available at very low cost via Cybersensor.com using an existing low-earth-orbit satellite system (ORBCOMM).

**Economic performance.** The single, 3-hp compressor was able to lift the wells and still run only 25% of the time, indicating that there was sufficient excess capacity to lift additional wells with little incremental cost. Prior to the test, Well 72-41 was produced using an API size 25 pumping unit with a 3-hp motor on a 25% time clock. Well 72-2 was produced using an API size 57 pumping unit with a 7.5-hp motor on a 25% time clock. Electrical power cost averaged $16/month during the test period, a 71% reduction in power costs, compared to combined

---

*Fig. 1. After a workover rig pulled rods and tubing from the wells, a PAMCO pumping system was installed in each. Inlet lines are ¾-in. steel tubing; return lines are 1-in. PVC. A 3-hp compressor supplies air for both wells.*
Company-operated, integrated, E&P waste management facility reduces costs

John Nussbaumer, Patina Oil & Gas Corp.

Bottom line. An integrated, E&P waste management facility has reduced Patina Oil & Gas Corp.’s costs for processing oil-contaminated soils and fluids, including tank bottoms. Disposal costs have been lowered from $20/yard, with liability attached, to under $4/yard, without the liability. With reuse of treated soil, cost of the landfarming operation is breakeven.

Background. Patina operates approximately 3,000 wells in the Greater Wattenberg field of the Denver-Julesburg basin. When evaluating E&P waste management options, two factors led to the company’s decision to design, permit, construct and operate its own waste management facility. First, E&P waste disposal at commercial facilities is expensive—about $20/ton of oily solids at a nearby commercial facility. And some facilities would not accept soil with more than 1% hydrocarbons. This contamination level is the clean-up standard under Colorado Oil and Gas Conservation Commission (COGCC) standards applicable to non-sensitive areas.

Liability was another important consideration. Commercial facilities tend to be under-capitalized and operated “on the cheap.” When things go wrong, as they have at one local facility that has been determined to represent an “imminent and substantial endangerment” under the Resource Conservation & Recovery Act, operators can become liable. Under RCRA, EPA has mandated a full investigation and remediation of the example site, and its operator has declared insolvency. Oil and gas operators may be liable for up to $3 million.

Considering these factors, Gerrity Oil & Gas, a predecessor to Patina, chose to pursue the company-operated E&P waste management facility option. The facility was to allow bioremediation of contaminated soil through landfarming, plus provide sludge treatment capability for oily drilling muds, tank bottoms and other sludges. Incoming sludge would be separated into salable product, clear water and residual solids, which would be incorporated into the landfarm for bioremediation.

Early in the permitting process, Gerrity encountered a dual jurisdictional problem between COGCC and the Colorado Dept. of Public Health and Environment (CDPHE). Ultimately, legislation specifying that COGCC had sole jurisdiction for “noncommercial” facilities was required. COGCC defines noncommercial as those accepting only E&P waste from one operator, or from a unitized area under a joint operating agreement. Even then, facilities must comply with local land use regulations.

Treating process. The processing facility contains two 340- by 105-ft soil-treatment cells. Soil that is not totally saturated with hydrocarbons is placed directly into one of the cells. “Dripping wet” saturated soils are placed into the sloped-bottom cement pit. At the lowest end of this pit, there is a chamber with a baffle to allow separation of oil and water. Tank bottoms or BS&W are pumped into either the open tank for immediate processing or into a 300-bbl storage tank for later processing. Material in the open tank is allowed to set for 24 hours to allow oil and water to separate. Oil is then pumped off to a tank fitted with an internal heater and heated to 160°F. The majority of the water is pumped into a lined pit fitted with a sprinkler system for evaporation. In the future, this water will be used to irrigate the treatment cells, thus speeding up the bioremediation process.

Oil from the heated tank is pumped through a heater treater for further separation. If needed, chemicals are added to assist separation. Separated oil is routed to the sales tank and water to the evaporation pit. To date, about 3,000 bbl of salable oil have been separated, bringing in revenue that helps defray operational costs. Residual solids are flushed out with water and routed to a sloping cement pit for mixing with soil, which is then spread in the treatment cells.

Landfarming process. To be degraded, crude oil requires catalysis by microbial enzymes and/or environmental modification. Environmental modifications can include suitable temperature, moisture, nutrients, pH adjustment, sunlight, oxygen and catalysts that break the hydrocarbon bonds making microbial action easier. In this facility, Patina incorporates sunlight, oxygen, suitable temperature and nutrients.

Soil placement in the cells is limited to depths of 12 to 18 in., since with greater depths, mechanical tilling is inadequate and the soil does not receive adequate aeration. To accelerate bioremediation, soil is tilled with a tractor pulling a cultivator twice a week. Initially, Patina tilled the...
soil a couple times a month and realized remediated soil (< 1,000 ppm) in nine months to a year. With twice weekly tilling, remediated soil is achieved in less than 90 days.

To preserve temperature during winter months, a road grader windrows the soil. Optimum pH range for bioremediation is 6.5 to 9.5; pH of the cells has ranged from 6.91 to 8.96. To date, Patina has not added moisture. For bioremediation, optimum moisture content is in the 20–30% range. Nitrogen and phosphorus nutrients are needed for the bioremediation process. Patina uses turkey manure, which is available locally for transportation cost only. To date, Patina has not had to use a bioremediation catalyst, which could reduce treating times to 30–45 days.

The Colorado Oil and Gas Conservation Commission and the Weld County Health Department require sampling of the soil remediation cells—semi-annually for oil and grease and pH, and annually for RCRA metals. Results for both cells are shown in Table 1. Heavy metal constituents are consistently well below regulatory levels. For example, the barium (a common contaminant in oilfield waste) levels well below 100 ppm are far below the regulatory level of 180,000 ppm. Sampling must be conducted annually for TPH 5-ft below ground. It was nondetectable during 1997 and 1998. All remediated soil is sampled prior to release. No soil is released unless hydrocarbons are below 1,000 ppm, and generally they are below 600 ppm.

Remediated soil is moved from the remediation cell to a staging area to be reused on field locations. Normally, this soil is used on lease roads, building up berms, replacing hydrocarbon-impacted soil in excavations and in building locations where needed. Soil that is brought into the waste management facility is accompanied by documentation showing where the soil came from. Similarly, documentation is kept on the final disposition of the remediated soil.

Economic benefits. Patina has incorporated successful, accelerated bioremediation of hydrocarbon-impacted soil and treatment of tank bottoms, which is producing salable crude oil and reusable soil—all at one central facility. Disposal costs have gone from $20 per yard of soil, with liability attached to less than $4 per yard, without the liability. With the reuse of the treated soil, the cost of the landfarming operation is a breakeven process for Patina.

Factors influencing whether landfarming would be attractive for other operators include:
- State/local regulations
- Availability of land
- Ground water or other environmental concerns where land is located
- Number of wells/size of operations.

In Colorado, if a company already owns the land and there are not groundwater/other environmental factors, the threshold size for landfarming operations could be in the 400 to 500-well range, depending on company circumstances.

ACKNOWLEDGMENT

This information has been presented, through an extended paper and field trip, as part of the “2000 Hazardous Waste Research Conference,” May 25 in Denver, Colo.

THE AUTHOR

John Nussbaumer is the environmental and safety coordinator for Patina Oil & Gas Corp. He has a BS in biology from Austin Peay State and a masters in environmental policy and management from the University of Denver. Before joining Patina in 1995, he was manager of environmental and safety for Occupational Management, Inc. and the Regional Transportation District. He has also served as a liaison officer to the United Nations.

Through 1999, more than 55 MMcf of gas vapors have been recovered with operating expenses of less than $0.40 per Mcf.

Prior problems. Historically, hydrocarbon vapor recovery from many oilfield production facilities’ oil and water storage tanks was considered uneconomical because of relatively low vapor volumes and low gas prices. In addition, compressor-based, vapor recovery systems could involve significant capital investment and often required excessive maintenance, which contributed to high operating costs. Changing conditions and improper monitoring or operation of the units led to high maintenance costs and related downtime. Too many times, vapor recovery systems were shut down to avoid ongoing high expense, especially in times of low oil prices.

Fullerton field waterflood central tank battery. Kerr-McGee Corp. designed and constructed the Fullerton Unit central tank battery facility in Fullerton field, Andrews County, Texas, late in 1994. The property in this case study and the field operations personnel responsible for its construction and operation were merged into Devon Energy Corp. in 1996. The facility was equipped with the pumping and production
equipment necessary to initiate and sustain waterflood operations. It also was designed to accommodate increased production from a planned, multi-year infill drilling program.

When designing the central tank battery, Kerr-McGee wanted a vapor recovery system that would:

- Be flexible as vapor volumes increased with increasing production volumes
- Have low operating costs
- Have minimal maintenance with its resulting downtime and cost.

They selected the patented Vapor Jet vapor recovery system, but wanted it modified from its normal configuration.

**Vapor recovery system.** The Vapor Jet system is ideal for facilities where the vapor volumes are on the low end of the range of compressor-based vapor recovery systems—sometimes referred to as “environmental units.”

The system uses produced water as the operating medium for a jet pump, Fig. 1. A single-stage, high-head centrifugal pump, driven by an electrical motor, is used to pressurize the produced water to 200–225 psig. The produced water enters the jet pump travelling through a nozzle, which converts it to a high-velocity stream as it enters the suction chamber, Fig. 2.

Tank vapors, at near-atmospheric pressure, are piped from the tanks to the suction chamber of the jet pump. The high-velocity water stream, which has created a vacuum in the suction chamber, entrains the vapors. The water stream, with entrained vapors, travels to the diffuser section of the jet pump where the kinetic energy of the high velocity stream is converted to potential energy, resulting in a pressure that is greater than the suction chamber pressure, but significantly less than the jet pump entry pressure. The discharge from the jet pump is piped to the low pressure separation system of the production facility (must be less than 40 psig for the jet pump to function with the 225-psig inlet pressure). Vapors are separated and sold with other lease gas from the low-pressure separation system. The produced water used is separated and returned to the water tanks.

In Kerr McGee’s installation, the operating medium for the jet pump is fresh water circulated in a closed system, which contains its own separator and water storage tank. The water is continuously circulated, with only the gas vapors exiting to gas sales.

There are three major system components: pressure controller, centrifugal pump and motor, and jet pump. The pressure controller is the same type used with compressor-based vapor recovery systems. When pressure in the vapor space of the tanks reaches a predetermined set point, the pressure controller activates the system by turning on the centrifugal pump. When sufficient vapor volumes have been removed to reduce the pressure to a predetermined point, the pressure controller deactivates the system by turning off the centrifugal pump.

The single-stage centrifugal pump and motor are the only components having moving parts, and are very durable, even when pumping produced water. Although lacking in efficiency, the single-stage centrifugal pump’s ability to develop a high head with the produced water—both reliably and with very little maintenance—more than compensates for its lower efficiency, when considering the overall cost of vapor recovery.

Jet pump sizing is based on anticipated vapor volumes, and the size of the jet pump determines the rate of water to be pumped. Although jet pumps will work at different pressures, the vapor jet systems utilize an inlet pressure of 200–225 psig. Discharge pressure must be less than 40 psig to create the required vacuum in the suction chamber.

The system can be installed for about 75–80% of the cost for compressor-based vapor recovery units in sour service and even less for sweet service. The three sizes of jet pumps currently in use, which allow recovery of up to 77 Mcf/d, utilize the same size single-stage centrifugal pump. Impeller diameter and size of the motor and motor starter will vary between applications. This flexibility allows the output of a particular size of installation to be increased with very little additional capital expenditures. Virtually, the only operating expense is the cost of the electricity to drive the centrifugal pump.

**Devon central tank battery installation.** At start-up of the facility, 15 wells produced about 400 bop/d, 300 bwpd and 150 Mcf/d total gas. With this production volume and facility operating conditions, tank vapor volumes were estimated at less than 20 Mcf/d, but would be increasing as planned infill drilling proceeded. The Vapor Jet system installed had a single-stage centrifugal pump and motor capable of supplying fresh water to a 2½-in. jet pump at 142-gpm and 200-psig. Under these conditions, the system was capable of recovering a maximum of 77 Mcf/d of tank vapors when operating continuously.

In 1997, lease production peaked at 1,500 bop/d, 1,000 bwpd and 230 Mcf/d. At this peak production rate, hydrocarbon vapors exceeded the capacity of the 2½-in. jet pump. A second pump and motor, with a 2-in. jet pump to operate in tandem with the first, was installed to recover the excess vapor volumes. The tandem jet pump, at 200-psig and 82-gpm, would recover up to 45 Mcf/d of additional tank vapors.

When vapor volumes began to decline, the tandem pumps operated in a “lead–lag” mode until vapor volumes were well within the capacity of the first larger jet pump. This freed the second pump for use in a stand–by capacity or for use elsewhere. Currently, lease production is 820 bop/d, 850 bwpd and 160 Mcf/d from 27 wells, and tank vapor volumes are well within the capacity of the first 2½-in. jet pump.

From initial installation through 1999, some 55 MMcf of hydrocarbon tank vapors have been captured and sold. Revenue from this
The equipment used is so durable that another 10–15 years of life is expected. This would lower the capital cost to the $0.20–0.25/Mcf range, providing vapor volumes equate to the first five years of recovery. Over the five-year life of the system, the only maintenance required has been an occasional pump packing, so downtime has been virtually nil. The only operating cost associated with the vapor recovery system has been the cost of electricity to drive the centrifugal pumps—a cost less than $0.40/Mcf of captured gas.

**Pilot test demonstrates how CO₂ injection enhances coalbed methane recovery**

Lanny Schoeling,* Kinder Morgan CO₂ Co., LP, and Mike McGovern, Burlington Resources Inc.

*lanny_schoeling@kne.com

**Bottom line.** Since 1995, Burlington Resources has been conducting a pilot test of enhancing coalbed methane recovery through carbon dioxide (CO₂) injection. The objective of the CO₂ injection pilot is to accelerate recovery, displace methane with CO₂ and recover incremental reserves. To date, 4.7 Bcf of CO₂ has been injected with only limited CO₂ breakthrough. Since primary production was increasing throughout most of the period due to dewatering, lowering of backpressures and well restimulations, reservoir simulation was an essential tool in analyzing pilot performance. It is estimated that injection to date will yield 1.6 Bcf of incremental reserves.

**Field history.** The Allison pilot is located in the San Juan basin in northern New Mexico. The coalseam target at the Allison Unit is the Cretaceous Fruitland coal formation. Average depth is 3,250 ft, with an average net thickness of 35 ft. Initial reservoir pressure was 1,650 psi, and the system was believed to be nearly 100% water saturated.

A map of the Allison Unit pilot is presented in Fig. 1. The nine Allison Unit production wells affected by CO₂ injection were originally completed on 320-ac spacing and placed on production starting in 1989. Initial gas and water rates averaged 100 Mcfd and 100 bwpd per well, respectively. Primary production steadily increased through 1999 due to dewatering, lowering of backpressures and reservoir restimulations.

At the time CO₂ injection was initiated in 1995, average production rates per well were 1,000 Mcfd and 30 bwpd, as shown in Fig. 2. Reservoir pressure in the flood area had declined to 1,200 psia. The initial produced gas composition of 95% methane and 5% carbon dioxide had remained relatively constant.

In the spring of 1995, a 36.2-mi, 4-in. diameter CO₂ pipeline was installed to deliver CO₂ from the Kinder Morgan Permian basin CO₂ supply line to the Allison Unit. CO₂ is received at a pressure of 2,200 psia. Pipeline friction losses and elevation heads result in wellhead injection pressures of 1,550 psia.

Four injection wells were drilled at roughly 160-ac infill locations. The injection wells were perforated and acidized, and CO₂ injection initiated in May 1995. Initial total injection rate was as high as 5 MMcfd, but declined quickly for the first few months to 4.2 MMcfd. This rapid decline in injectivity was possibly due to near wellbore coal matrix swelling caused by adsorption of CO₂ and transient pressure buildup near the injectors.

After 6 months, injection was temporarily halted for evaluation. Since resuming injection in July 1996, the injection rate has been fairly constant at about 3 MMcfd, although injection ceased again temporarily late in 1997 so that surface CO₂ lines could be buried. A plot of

---

**Fig. 1.** The nine Allison Unit production wells affected by CO₂ injection were completed originally on 320-ac spacing. Four injection wells were drilled at 160-ac infill locations, perforated and acidized. CO₂ injection began in May 1995.

**Fig. 2.** When CO₂ injection began in 1995, average per-well production was 1,000 Mcfd and 30 bwpd. Reservoir pressure in the flood area had declined to 1,200 psia.
Quantifying incremental methane production from CO₂ injection was difficult due to several factors. The injected volume relative to the produced volume is very small (producing 30 MMcf/d, while only injecting 3.5 MMcf/d). Primary production was increasing at the start of injection and continued to rise through March 2000 due to dewatering, lowering of backpressures and well restimulations. Since there was not an established decline, reservoir simulation was essential for estimating incremental recovery.

The simulator selected to evaluate the pilot’s incremental performance is COMET 2—a three-dimensional, two-phase, single, dual or ‘triple’ porosity simulator for modeling gas and water production from coal seams. It has a binary gas sorption feature, which defines the non-linear relationship between free and adsorbed multi-component gas mixtures (methane-nitrogen and methane-carbon dioxide) as a function of methane concentration using extended Langmuir theory.

The simulator was used to match actual primary and enhanced production in the Allison Unit and then to estimate the fraction of actual production attributable to CO₂ injection. The following procedure was used to estimate incremental methane production. First, a history match of total performance (including CO₂ injection) was completed, driving the model with actual injection and production rates. Flowing bottomhole pressures derived from this history match were used as input to drive a second projection, representing what primary production would have been without CO₂ injection (assuming the same operating conditions). Subtracting the second case (primary production) from the first case (enhanced production) yields incremental recovery rates. Both cases were projected into the future with the same flowing bottomhole pressure assumptions.

The simulation grid size was (18 × 24 × 4). Prior to production, the reservoir was assumed to be 100% water-saturated at an initial pressure of 1,650 psia. Isotherm curves were taken from lab core studies, and the Langmuir volumes for the methane and CO₂ were 33.2 and 50.09 Mcf/cf, respectively. Langmuir pressures for methane and CO₂ were 539 and 239 psia, respectively.

Areally, cleat permeability and porosity were estimated from production data. Once overall material balance calculations matched, the relative permeability was varied to get a reasonable field match on water production. Individual wells were matched by varying skin factors on wellbores. Permeability was varied as a function of reservoir pressure to simulate permeability growth due to matrix shrinkage effects.

The original gas in place in the model was 131.5 Bcf. Fig. 3 (data as of July 2000) indicates significant CO₂ adsorption near the injection wells, illustrating why CO₂ breakthrough has not been a major problem. Cumulative CO₂ injection has been 4.7 Bcf to date, with ultimate, incremental methane recovery estimated at 1.6 Bcf, assuming injection is discontinued. Fig. 4 illustrates incremental methane production as a function of cumulative CO₂ injection.

Lessons learned. Much was learned from the Allison Unit project, which is applicable to future commercial projects. Effectiveness of reservoir simulation in evaluating project performance was proven. From a process standpoint, field performance established that feared CO₂ breakthrough was not a major problem. With breakthrough not being a major problem, future projects might avoid the shut-in of producers for a period of time and begin injecting CO₂ at higher rates. Incremental recovery equates to a CO₂ requirement of about 2.9 Mcf of CO₂ per Mcf of incremental gas, a guiding parameter for other operators to consider when they evaluate the attractiveness of CO₂-enhanced coalbed methane recovery. In the San Juan basin, CO₂ prices vary from 10 to 13% of natural gas prices, depending on the demand situation for carbon dioxide.

THE AUTHORS

Lanny Schoeling is senior staff reservoir engineer with Kinder Morgan CO₂ Co. in Houston. His primary responsibilities are simulation and evaluation of potential CO₂ candidates throughout the U.S. Prior experience includes director of the Mid-Continent PTTIC organization and enhanced oil recovery engineer for the Tertiary Oil Recovery Project. He holds a doctorate of engineering and an MS in chemical engineering from the University of Kansas. He is a licensed engineer in Texas and Kansas.

Mike McGovern is an engineering advisor with Burlington Resources’ San Juan Division. He holds a BS in petroleum engineering from Louisiana State University, and is a registered engineer in Oklahoma. His major focus since 1993 has been exploitation of coalbed methane in the San Juan basin. Mr. McGovern has 18 years experience, has specialized in reservoir engineering and has worked in enhanced oil recovery operations, including miscible flue gas flooding and polymerflooding.