HY-BON Engineering Company, Inc.

Petroleum Technology DIGEST™

For Independent Producers ■ Supplement to *World Oil®* Magazine September 2000

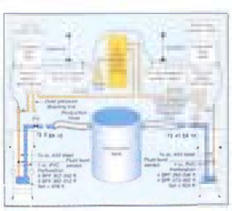
■ **Major reserve increase obtained by dewatering high-water-saturation reservoirs**

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, Bretagne 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

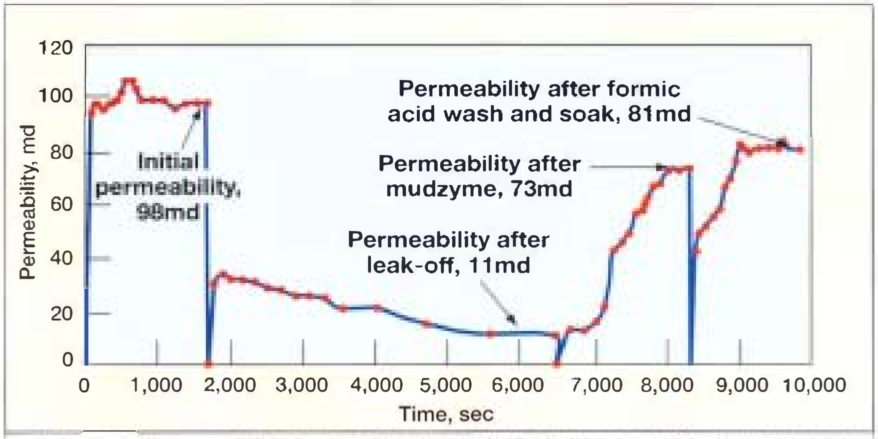


***Fig. 1.** Final return permeability after the acid soak was 98% for the lab mud and 83% for the field mud. Treatment was an enzyme soak, followed by an 8% formic acid soak.*

Polymer-specific enzyme breaker improves completion efficiency in horizontal wells

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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 wells referenced in this case study are located in one fault block in the Lower Member A sands. 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

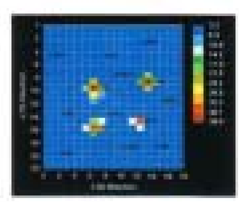
■ **Company-operated, integrated, E&P waste management facility reduces costs**

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 CO_2 injection enhances coalbed methane recovery**



Since 1995, Burlington Resources has been conducting a pilot test of enhancing coalbed methane recovery through carbon dioxide (CO_2) injection.
see page 14

Table 1. Soil cell sampling history—Zone of incorporation sampling results (ppm)

Date	Ba	Cd	Cr	Ag	As	Pb	Se	Hg	Oil/Grease	pH	Cell
8/95	36.5	ND	3.87	ND	1.5	3.9	ND	ND	136	8.10	N/A
6/96	55	ND	5.46	ND	1.3	4.7	ND	ND	974	8.20	East
11/96									500	8.96	West
5/97	75.2	0.31	6.4	ND	10.2	10.2	ND	ND	50	7.99	East
11/97									190	8.00	East
11/97									1,100	8.89	West
5/98	23	ND	3.1	ND	ND	9.4	ND	ND	<20	6.91	East
5/98	19	ND	2.2	ND	ND	5.2	ND	ND	<20	7.74	West

ND = non-detect for applicable parameter detection limit

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.

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

Troy Palmer, Devon Energy Corp., **Bill Webb,*** Bill Webb, Inc., and **Dale Redman,**** Hy-Bon Engineering Co., Inc

Bottom line. 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. The system has proven to be a reliable, flexible, cost effective alternative for capturing hydrocarbon vapors to increase gas sales, while reducing hydrocarbon emissions. 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

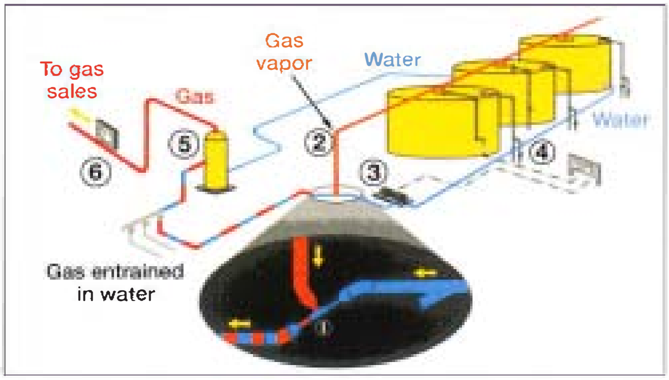

Fig. 1. The Vapor Jet vapor recovery system uses produced water as the operating medium for a jet pump to entrain tank vapors and return them to the low-pressure separation system for separation and sale.

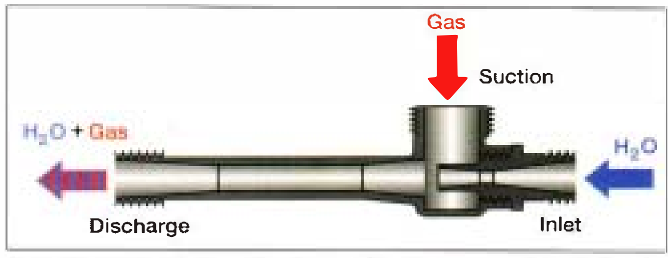

Fig. 2. Tank vapors enter the suction chamber of the jet pump and a high-velocity water stream, which has created a vacuum in the suction chamber, entrains the vapors. The jet pump discharges to the production facility's low-pressure separation system.

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 Mcfd, 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 bopd, 300 bwpd and 150 Mcfd total gas. With this production volume and facility operating conditions, tank vapor volumes were estimated at less than 20 Mcfd, 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 Mcfd of tank vapors when operating continuously.

In 1997, lease production peaked at 1,500 bopd, 1,000 bwpd and 230 Mcfd. 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 Mcfd 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 bopd, 850 bwpd and 160 Mcfd 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 captured gas has been about $91,000. Unit capital cost to date equates to only $0.45/Mcf of captured gas. With a much longer anticipated life, ultimate unit capital cost will be significantly lower.

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.

THE AUTHORS

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Bill Webb, president of Bill Webb, Inc., served as a production operations consultant for Kerr McGee/Devon for the vapor recovery installation. He holds a BS in petroleum engineering from Louisiana State University. Prior to consulting work, he spent 22 years in various engineering and operational management positions with Conoco Inc.

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Pilot test demonstrates how CO_2 injection enhances coalbed methane recovery

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Bottom line. Since 1995, Burlington Resources has been conducting a pilot test of enhancing coalbed methane recovery through carbon dioxide (CO_2) injection. The objective of the CO_2 injection pilot is to accelerate recovery, displace methane with CO_2 and recover incremental reserves. To date, 4.7 Bcf of CO_2 has been injected with only limited CO_2 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 CO_2 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 CO_2 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 CO_2 pipeline was installed to deliver CO_2 from the Kinder Morgan Permian basin CO_2 supply line to the Allison Unit. CO_2 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 CO_2 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 CO_2 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 CO_2 lines could be buried. A plot of

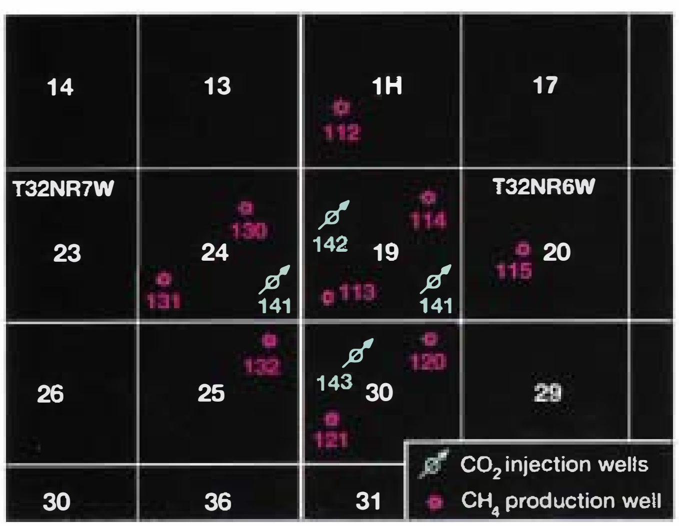

Fig. 1. The nine Allison Unit production wells affected by CO_2 injection were completed originally on 320-ac spacing. Four injection wells were drilled at 160-ac infill locations, perforated and acidized. CO_2 injection began in May 1995.

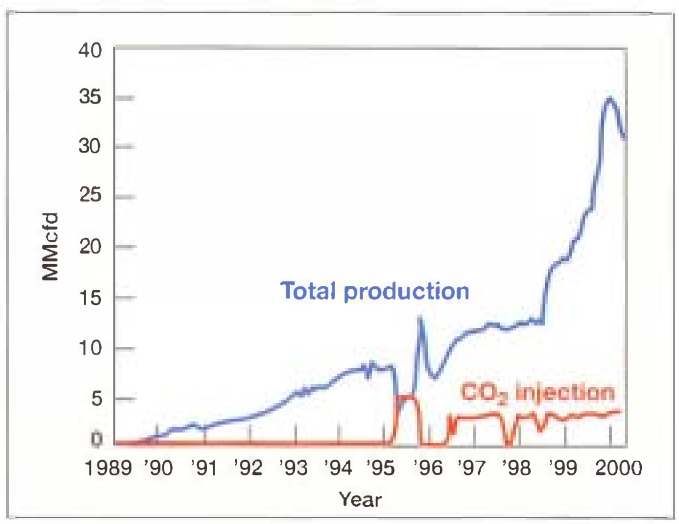

Fig. 2. When CO_2 injection began in 1995, average per-well production was 1,000 Mcfd and 30 bwpd. Reservoir pressure in the flood area had declined to 1,200 psia.