OPERATING PRACTICES IN THE NORTH CROSS CO_2 FLOOD

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INTRODUCTION

The North Cross Devonian Unit is located in the Crossett Field at the southern edge of the central basin platform in West Texas. The reservoir is a chalky, siliceous carbonate with 21% porosity, 3 md permeability and has an average pay thickness of 90 feet. There are 17 producers, 6 CO_2 injectors, 3 residue gas injectors, and 2 TA wells in the unit (Fig. 1).

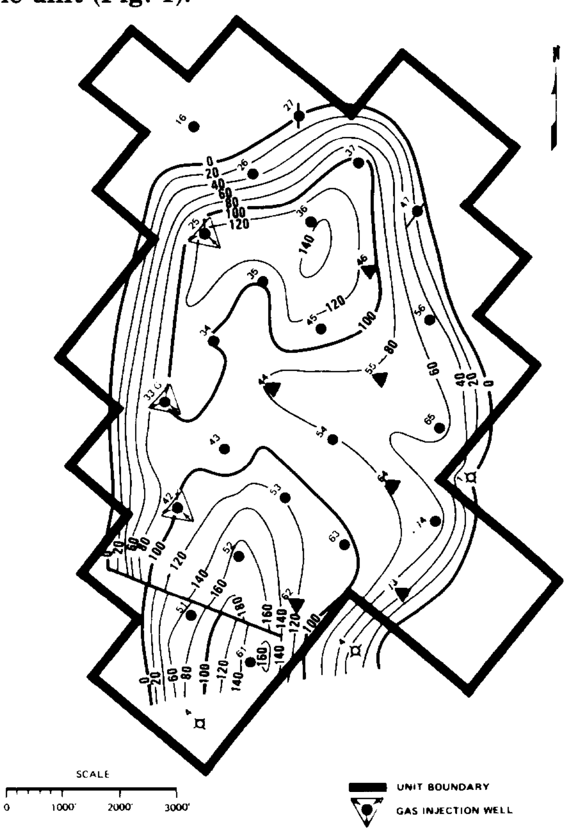

FIG. 1—NORTH CROSS (DEVONIAN) UNIT GROSS PAY ISOPACH

In 1964, residue casinghead gas injection was started to maintain reservoir pressure, and CO_2 injection was begun in 1972. Response to CO_2 injection occurred in one well early in 1973 and by late 1974, four wells were showing signs of response. As of the end of 1974, the unit produced 56,000 BOPM, with a GOR of 8000. Figure 2 shows the unit's performance since 1964. To date, the only major operating problem has been a decline in CO_2 injectivity.

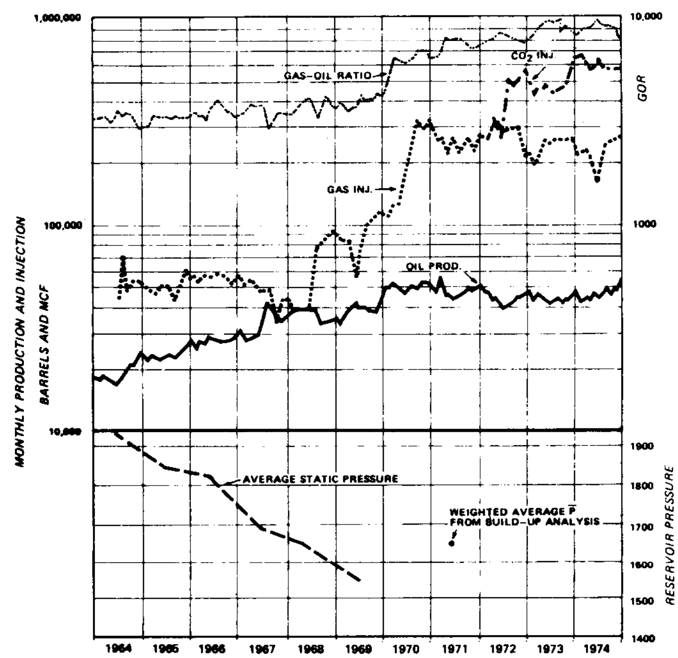

FIG. 2—NORTH CROSS (DEVONIAN) UNIT PERFORMANCE HISTORY

CO_2 PROJECT

The primary recovery mechanism in the Crossett field is solution gas drive, and recovery efficiency is estimated to be 13%. By 1964, reservoir pressure had declined from an initial pressure of 2500 psi to approximately 1900 psi and a pressure maintenance project was started by injecting casinghead gas. It was estimated that this method would improve recovery efficiency to only 19% and other methods of secondary recovery were investigated to find a method that would further improve recovery efficiency. Waterflooding was ruled out because of the low permeability, and many miscible displacement processes were ruled out because they require at least 3000 psi reservoir pressure. The miscibility pressure for CO_2 was measured to be 1650 psi, and this along with the low permeability and high gravity crude (44° API) made the North Cross unit an attractive CO_2 project. Recovery efficiency with CO_2 is estimated to be 42%. Based on the cost and availability of CO_2 and estimated life, the project was designed for 20 MMCF/D CO_2 injection.

In April 1972, CO_2 injection was started into four wells at 20 MMCF/D and residue gas injection was maintained. At present reservoir temperatures and pressures the CO_2 voidage ratio is 0.4 reservoir bbl to one MCF CO_2. Because of this unfavorable ratio, withdrawals would far exceed injection and the bottomhole pressure would soon decline well below the 1650 psi miscibility pressure and most advantages of CO_2 injection would be lost. Therefore, all produced casinghead gas is reinjected to maintain reservoir pressure at or above miscibility pressure. A numerical reservoir simulation was used to determine that the optimum pattern would be an inverted nine-spot.

SURFACE FACILITIES

The surface facilities for this project are not unlike those used in a waterflood. The major difference is that there are two primary injection systems, one for CO_2 and one for residue gas, and a secondary system to handle casinghead gas contaminated with CO_2.

Carbon dioxide is supplied by pipeline at approximately 1700 psi and is compressed to 2400 psi for injection into the CO_2 injectors. This sytem handles dry CO_2 and no corrosion protection is required.

Produced fluids are gathered at a central facility and the casinghead gas is sent to the Shell Tippett Gas Plant for processing. The residue gas is returned to the lease at 750 psi and compressed to 2400 psi for reinjection into the gas injection wells.

The Tippett Plant cannot adequately process a gas stream with more than two percent CO_2 contamination, and a secondary system is being installed in the North Cross Unit to handle the contaminated gas. When this system is completed, we will be able to isolate those wells producing highly contaminated gas. The contaminated gas will be compressed on the lease to 750 psi and sent to the reinjection compressor to be mixed with residue gas and injected into the gas injection wells.

The pressure at which the system for handling contaminated gas is operated has a noticeable effect on operating costs, and as the volume of contaminated gas increases, the effect will be more noticeable. Presently, the system is being operated at 25-50 psi and the contaminated gas must be compressed up to 750 psi which is the suction pressure of the reinjection compressor. An increase in the system operating pressure will reduce compression costs. Naturally, a higher system operating pressure causes a higher wellhead pressure against which the wells must flow. It is anticipated that by the time the volume of contaminated gas is high enough to load the contaminated gas compressor, flowing bottomhole pressures will be high enough to sustain a high rate against at least 250 psi back-pressure, and 500 psi separation facilities are now being installed.

Most equipment in the surface gathering system exposed to corrosive fluids is protected with plastic or stainless steel. In addition to this, liquid corrosion inhibitors are injected into flow lines downstream of the well heads, and misting corrosion inhibitors are injected into the contaminated gas system between the separators and compressor.

DOWNHOLE FACILITIES

Nearly all wells are completed open hole with either 5-1/2 in. or 7-in. casing set at the top of the reservoir pay (approximately 5300 ft). Producing wells are completed with a packer and an on-off seal connector with a profile nipple. If any work must be done above the packer, a plug can be set in the profile nipple and the tubing pulled without having to kill the wells. The packer, profile nipple and on-off seal connector are protected with plastic. The tubing will not be protected against corrosion until the corrosion rate in the produced fluids is measured at 5 mils per year. When corrosion protection in the tubing is required, fiberglass-lined tubing is used. Fiberglass was chosen over polyvinylchloride or other plastics because of its resistance to wireline damage.

Injection wells are equipped similarly to producing wells. No corrosion problems are anticipated with dry CO_2 or residue gas and the tubing is not protected. In order to prevent collar leaks, the tubing collars have been modified; the modification consists of a groove cut into the inside of the collar one inch from either end and Teflon rings fitted into the grooves. In addition to this, the tubing is nitrogen-tested to 6000 psi when run.

The casing in nearly all of the wells is not cemented to surface and casing leaks have been a problem. Some wells have pressure on the bradenhead caused by San Andres water behind uncemented casing. We generally cement the wells to surface if we have to work on them for any reason or if the bradenhead pressure approaches 100 psi. To protect the repaired casing against excessive pressure in the injection wells should they develop a tubing leak, an annulus relief system has been installed and is set to vent the annulus should the annular pressure exceed 1000 psi.

SURVEILLANCE

Several surveillance tools are used at North Cross. These include well tests, gas analyses, bottomhole pressure data, Delta II's and radioactive tracer surveys.

Well tests are reported monthly along with casing, flowing tubing and bradenhead pressure. If the bradenhead pressure on any well approaches 100 psi, the well is shut in and cement circulated to surface outside the casing. One-hundred psi was chosen because a column of San Andres water exerting 100 psi at the surface, would exert approximately 1000 psi at the San Andres. If the casing has been weakened by corrosion, we do not want more than 1000 psi external pressure exerted on it.

Casinghead gas is analyzed monthly for CO_2 content and produced fluids are monitored monthly for corrosion rate. If either the CO_2 content of the gas or the corrosion rate seems to be increasing, both are monitored more frequently. The CO_2 content is monitored mainly as an indication of response; but, because the corrosion rate is a function of CO_2 partial pressure, increasing CO_2 content is a warning to watch for increasing corrosion rates.

Injection rates and pressures are measured daily along with CO_2 temperature, and compressor suction and discharge pressure. A 72-hour pressure fall-off is taken in each injection well at least once a year or more frequently if a radical change in injectivity occurs. Radioactive tracer surveys are run yearly in all injection wells and at more frequent intervals if any significant profile changes occur between the yearly surveys or if any significant changes in injectivity occur.

Pressure buildup surveys are usually taken once every two years but flowing bottomhole pressure surveys are taken on an average of twice a year. Figure 3 shows the response curve of the first unit well to respond. Response is indicated first by falling GOR with fairly unchanged oil production. There seems to be a six to nine-month lag between rising oil production and falling GOR. During this period, a well may need artificial lift to maintain its rate of production. The flowing bottomhole pressure and well test data are used to construct IPR curves to determine if and when artificial lift should be installed. Eventually the bottomhole pressure will increase, and, as CO_2 breakthrough

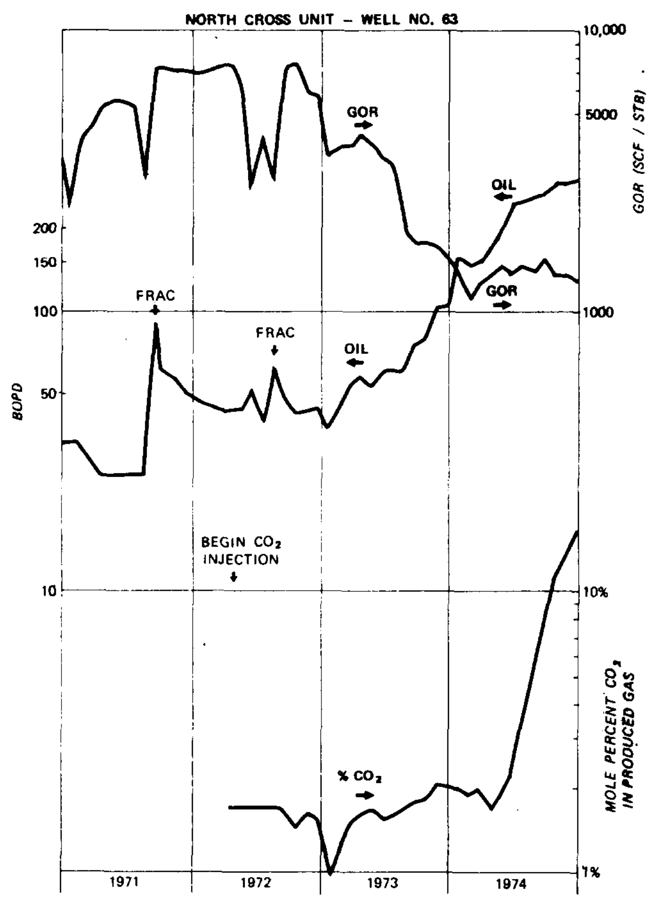

FIG. 3

occurs, the GOR will increase, and a well can be returned to a flowing status. Fluid level and Delta II data are used to help determine when the artificial lift should be removed. Once a responding well is returned to a flowing status, it is allowed to flow at as high a rate as possible until the GOR reaches 1600 (the solution GOR); at this time, the rate is reduced to maintain a 1600 GOR or less. We hope to minimize premature CO_2 breakthrough with this practice.

INJECTIVITY PROBLEMS

The most troublesome problem in the North Cross Unit is that of declining injectivity. The project was designed for an injection rate of 20 MMCF/D CO_2 into four injection wells. The numerical reservoir simulation predicted that injectivity would increase throughout the life of the project and pressure fall of data in the injectors indicates an increasingly negative skin with time. However, injection rates have fallen off as much as 2 MMCF/D in some wells. This phenomenon is unique to CO_2 injectors, for no injectivity decline has been observed in the residue gas injectors. In the past, our solution to this problem has been to increase the number of injectors by converting producers to injectors until we now have six injectors in a five-spot instead of the original inverted nine-spot.

While running tracer surveys in the injection wells in 1974, a black paraffin-like material was recovered from several injection wells. A chemical analysis indicated that it was not paraffin, but some type of corrosion inhibitor probably carried in the CO_2 stream from the gas plant that supplies the CO_2. A solvent was found that would disperse the material and the wells were given a solvent wash followed by a small acid wash. Individual post treatment injectivities were improved by as much as 4 MMCF/D in some wells and no improvement was observed in one well. Those wells that had an injectivity improvement gradually declined over a two-month period to slightly above their pretreatment injectivity, but the total sustained field injectivity increased by 1.8 MMCF/D.

If an injection well is shut in for one or more days and returned to injection, its injectivity is usually higher than its pre-shut-in injectivity but declines rapidly (usually in two days) to its former injectivity. This behavior indicates something like a slowly expanding pressure front in the formation. When a well is shut in, the front continues to expand at the expense of pressure on the wellbore side of the front. When injection is restarted, the well will take at a high but decreasing rate until equilibrium is reached.

SUMMARY

The Devonian reservoir at North Cross is ideally suited for a CO_2 miscible displacement project because of its low permeability and high gravity crude. The recovery efficiency of a CO_2 project is estimated to be 42% of the original oil in place compared to 13% efficiency for primary and 19% for residue gas injection.

The project is designed for 20 MMCF/D CO_2 injection for miscible displacement while reinjecting residue casinghead gas to maintain the reservoir pressure at or above 1650 psi miscibility pressure.

Three injection systems are being used in the project, one for CO_2, one for residue gas and one for produced gas contaminated with CO_2. The contaminated gas is processed on the lease and compressed up to the suction pressure of the residue gas injection compressor and reinjected in the gas injection wells. To reduce compression costs of the contaminated gas system, it will be operated in the 250-300 psi range at a later date.

Progress of the project is monitored with well tests, gas analyses, corrosion checks, shut-in and flowing bottomhole pressures and radioactive tracer surveys.

Declining injectivity has been and continues to be the most significant operating problem. To date, the only solution to the problem has been to convert additional wells to injectors. The causes of this problem are not fully understood but are suspected to be reservoir conditions rather than wellbore conditions.

To date, one well is very definitely responding to CO_2 injection and at least four other wells are beginning to show signs of response.

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