FIELD IMPLEMENTATION OF A CO_2 FLOOD IN A SMALL WATERFLOOD-DEPLETED CARBONATE UNIT

Kimberly B. Dollens, Phillips Petroleum Company
Ken J. Harpole, Phillips Petroleum Company
Larry D. Hallenbeck, Phillips Petroleum Company

ABSTRACT
The South Cowden (San Andres) Unit was selected as the site for one of three mid-term projects to be conducted under the DOE Class II Oil Program for Shallow Shelf Carbonate Reservoirs. The \$21 million project was designed to demonstrate the technical and economic viability of an innovative carbon dioxide (CO_2) flood project development approach. The new approach employed cost-effective advanced reservoir characterization technology as an integral part of a focused development plan utilizing horizontal injection wells, where appropriate, and centralization of production/injection facilities to optimize CO_2 project economics. This paper will review actual implementation and field performance in the first eighteen months of the project, focusing on key issues of timing, stimulation, injection profile monitoring, reservoir pressure reduction, and conformance control. A comparison will be presented of initial simulation model results with current predictions.

INTRODUCTION
The South Cowden field is located about five miles south of the city of Odessa in Ector County, Texas, and produces primarily from the Grayburg and San Andres formations of Permian age. These formations were deposited in shallow shelf carbonate shelf environments along the eastern margin of the Central Basin Platform. The primary target for carbon dioxide (CO_2) flood development under the proposed project is a 150-200 foot gross interval within the San Andres at an average depth of 4550'. The original oil-in-place for the Unit area is estimated at approximately 100 MMSTBO. A summary of reservoir and fluid characteristics is included as Table 1.

South Cowden was discovered in 1940 and unitized for secondary recovery operations beginning in 1965, with initial water injection into peripheral wells located around the edge of the producing structure near the oil/water contact. Leaseline cooperative injection was commenced in the early 1970's along the northern boundary with the Emmons Unit. From the late 1970's through the mid-1980's additional water injection wells were strategically placed at selected locations within the Unit, however no formal injection pattern was utilized.

The use of horizontal injection wells at the South Cowden Unit (SCU) water-alternating-gas (WAG) CO_2 project area reduced the overall drilling and CO_2 distribution costs, and is considered a key element of the economic success of the project. The project is unlike other conventional San Andres CO_2 floods in that no formal injection pattern was utilized. At the start of the CO_2 project, the Unit was nearing its economic limit, producing about 400 BOPD at a water-cut in excess of 95% from 38 active producers and 15 active water injectors. Ultimate primary plus secondary recovery is calculated at 35 MMSTBO or approximately 35 percent of the original oil in place (OOIP). Waterflood performance on the Unit was considered excellent. Tertiary recovery is anticipated to be 11.5 MMBO, or 12% of OOIP for the Unit area (16% for the project area, which has an estimated 70 MMSTBO OOIP).

GEOLOGIC DESCRIPTION

The San Andres is a vugular dolomite sequence with the upper 40 feet (on the average) usually being non-porous. The porous section then encountered is the normal pay zone of the Unit area.

Contours drawn on the base of the Cowden Sand (Figure 1) indicate the structure to be a south-plunging end of a large anticline. Structural relief over the area is about 300 feet with dips ranging from less than 100 feet to greater than 250 feet per mile. The thickness of the net pay (normally restricted to the San Andres) averages about 50 feet. Average porosity over the Unit area is approximately 12 percent. Porosity pinch-outs are indicated in the vicinity of Wells No. 2-19 and 2-15 in Section 7. Permeability data range from 0.6 millidarcies (md) to 6.6 md in the pay intervals, with a 3.7 md average.

RESERVOIR CHARACTERIZATION

Regional mapping and 3-dimensional (3-D) seismic data indicate that sediments within the reservoir interval were draped over a paleohigh resulting in an unfaulted, anticlinal structure. A field-wide stratigraphic framework was developed using gamma-ray markers which correspond to the low permeability, sand dolomite layers recognized above. These log correlations indicate fairly simple and uniform structure and stratigraphy. The gamma-ray markers delineate four zones within the 150 foot reservoir interval. Rocks composing these zones are extensively dolomitized and display a complex color mottling. Refer to Figure 2 for a type log.

Color mottling characterizes the reservoir interval due to variable hydrocarbon staining and reflects a variation in porosity and permeability. This mottling is most likely related to bioturbation of carbonate sediments in a shallow, subtidal marine environment. Variations in the quality and thickness of the mottled facies are major parameters controlling oil recovery. A thin region of better reservoir-quality rock runs roughly parallel to structure and results in an area of higher cumulative production. Good waterflood response and uniform pressure distribution indicate continuity of the pay zones within this region.[1]

Another major factor contributing to reservoir quality at SCU is the extent of anhydrite cementation. As expected, greater amounts of anhydrite result in lower porosity and lower permeability Anhydrite is both a depositional and diagenetic mineral. Bedded anhydrite is formed by precipitation in bodies of saline brine. No bedded anhydrite has been observed in the South Cowden field. Diagenetic anhydrite occurs as nodules, poikilotopic crystals and cement. All of these forms have been found in the South Cowden field. The anhydrite most likely originated in hydrous form, gypsum, and was created along with dolomitization and was later converted to the anhydrous form, anhydrite, as burial and temperature increased.[2]

Limited core data suggests that anhydrite percentage increases to the northwest across the Unit (toward the paleoshoreline). This conclusion is further supported by observing that porosity and well productivity drop significantly in the western and northwestern portions of the Unit.

WAG INJECTION WELL FACILITIES

Figure 3 is a map of the Unit area indicating the location of all the current CO_2 WAG injection wells, including two vertical injectors in Section 7 (2-26W and 2-27W), two horizontal injectors in Sections 17 and 18 (6C-25H and 7C-11H), and three leaseline injectors (6-26W, 6-27W, and 6-28W). Also noted is the location of the centralized facilities in Tract 6, which are shared with the Emmons Unit to the north.

The two Section 7 vertical injection wells and the two horizontal injectors were drilled and completed during early 1996, and placed on injection during July and August, 1996. The Tract 6 leaseline injection wells were drilled during early 1997, and have been place on injection at various times as identified profile injection/conformance problems have been rectified. Leaseline injection Well 6-28W has not as yet commenced CO_2 injection services due to CO_2 channeling in the lower San Andres.

All the vertical injection wells were equipped with standard equipment: 5-1/2" , 15.5 pounds per foot (ppf), J-55 LT&C casing to total depth and 2-7/8", J-55 internally plastic-coated tubing. The vertical wells were designed to take 500-1000 Mscfd of injected CO_2.

The trajectories of the CO_2 WAG horizontal injection wells were planned to optimize reservoir performance, maximize sweep efficiency, and optimize injectivity performance. The wells were designed mechanically to optimize well injection performance and maximize the duration of their utility. Both wells were equipped with 9-5/8", 36 ppf, J-55 surface casing; 7", 20 ppf, J-55 production casing through the curve; and a 6-1/8" openhole injection interval. The production casing was sized at 7" to accommodate 3-1/2" production tubing. The 20 ppf casing weight was employed for additional corrosion wear allowables. The cased curve trajectory was designed to accommodate 125' of production casing within the top of the San Andres producing interval, in order to maximize injection packer setting depths while minimizing corrosion exposure of casing below the packer.

In order to minimize friction loss down the tubing, 3-1/2" injection tubing was employed. The entire downhole injection assembly was designed to resist CO_2 corrosion effects by lining the tubing with fiberglass inserts and coating the injection packer internally with plastic and externally with nickel plating. Stainless steel injection trees were also utilized to minimize corrosion. The completion strings for Wells 6C-25H and 7C-11H are included as Figures 4 and 5.

The location of the surface locations of the two horizontal wells in Tract 6 allowed for the centralization of production and injection systems at the Tract 6 tank battery. This helped to minimize costs by an estimated 11 million dollars primarily by reducing investment costs for drilling and equipping WAG injection wells, eliminating the need for an extensive CO_2 distribution system, and reducing surface facilities costs. Additionally, the centralization of production, gas recycling, and injection facilities minimized costs related to gas handling and distribution.[3]

HORIZONTAL WELL INJECTION PROFILES

Injection profile logs were run on the horizontal injection wells during both water and CO_2 injection to ensure proper placement of the injectants. Memory logging tools were used to obtain quality, interpretable logs under both water and CO_2 injection. The memory logging string consisted of any and all available tools, including correlation gamma ray and collar-locator log; injection and shut-in temperature, capacitance, flowmeter and pressure gradient. A radioactive-interface log was run during water injection, but was not utilized during CO_2 injection out of concern for contamination of the downhole equipment. During CO_2 injection, nitrogen was used to purge the injection string in order to avoid abrupt pressure changes which cause CO_2 icing problems.

The injection profile log on 6C-25H during water injection indicated fluid loss throughout the openhole interval, with major fluid loss at 5340'-5480' wireline depth (WL), and lesser losses at 4940'-4990' (near the casing shoe), 5185'-5275', 5655'-5695', 5775'-5870', and 6210'-6295' WL, for a total injection zone of approximately 250'. These findings were confirmed with the results of a pressure fall-off test which indicated radial flow through about 250' of zone. The one-hour shut-in temperature log and concurrent gamma-ray pass indicated crossflow from 6638'-6295' WL while the well was shut-in. This was surmised to be the result of water injection and thus pressure support from nearby well 5-01W, which was injecting up until mid-summer 1996. The subsequent profile log run during CO_2 injection confirmed these results, with further evidence of cross-flowing from the end of the horizontal section to approximately 6620' WL.[4]

The initial profile log run on Well No. 7C-11H during water injection utilized a coiled tubing and wireline system which yielded un-interpretable results. Therefore, the memory-based system was employed for the second profile run during CO_2 injection, and was later confirmed using a similar system under water injection. Under CO_2 injection, injection and shut-in temperature passes indicated fluid loss out of the toe of the horizontal section, with major loss at 6130'. Subsequent fall-off and step-rate testing did not show the same behavior as demonstrated in the 6C-25H; the tests both showed early linear flow behavior rather than early radial flow, suggesting flow in a fracture system This second horizontal injection well was drilled approximately normal to the preferential parting direction indicated in earlier microfracture tests conducted on two reservoir characterization wells within the Unit.[5]

The subsequent profile log run during water injection confirmed the loss of the fluid in the toe of the well, but identified two primary zones of fluid loss in the well at 6100'-6110' and 6150'-6180' WL. The remediation of the injection problem in the toe of this well is top priority for the project team during 1998.

TRACT 7 VERTICAL WELL INJECTION PROFILES

Water injection commenced in vertical WAG injection Wells Nos. 2-26W and 2-27W in early July, 1996. Bottom-hole pressure surveys were run in both these vertical injection wells during late July, immediately prior to commencing CO_2 injection. CO_2 injection began July 19, 1996 in Well No. 2-26W, at an initial wellhead pressure of 890 psig and injection rate of 200 thousand standard cubic feet per day (Mscfd). CO_2 injection commenced July 22, 1996 in Well No. 2-27W, at an initial wellhead pressure of 1000 psig and injection rate of 200 Mscfd.

The initial injection profile survey on Well No. 2-26W was run under CO_2 injection in November, 1997. That injection survey indicated that, although the CO_2 was leaving the wellbore through all the perforations relatively consistently, the shut-in temperature passes indicated no storage of the CO_2 within the target zone and CO_2 channeling down below logged total depth (LTD).

The initial injection profile survey on Well No. 2-27W was also run under CO_2 injection in November. Both the tracers and the temperature passes indicated over forty percent (40%) of the CO_2 was going out the bottom set of perforations (4637-4646') with movement down below LTD.

Because of the compressibility of CO_2, the shut-in temperature passes under CO_2 injection are likely not fully shut-in at bottom-hole. For this reason, another set of injection profile survey will be run on these wells while on water injection to confirm these logging results.

COOPERATIVE LEASELINE VERTICAL WELL INJECTION PROFILES

The leaseline vertical injection wells were all drilled and completed during late 1996. Vertical WAG injection Wells Nos. 6-26W and 6-27W were placed on water injection during January, 1997. Initial injection profile surveys were run while on water injection during early February, 1997.

SCU Well No. 6-26W

The initial injection survey on Well 6-26W indicated communication between a water sand at 4344-4355' and casing perforations 4568-4572' and 4578-4582'. During the shut-in period, the log indicated that flow from the water sand was entering the wellbore through the perforations in communication at a rate of 35 bpd and was cross-flowing into the selectively-perforated interval 4592-4726'.

The injection survey also suggested that the selectively-perforated intervals below 4700' (4709'-4711', 4716'-4718', and 4724'-4726') were taking approximately 15% of the injection water with evidence of downward channeling. A remedial workover was proposed to squeeze the selectively-perforated interval 4709'-4726' and the selectively-perforated interval 4568'-4582' in an effort to limit out-of-zone injection.

A workover was performed during early April, 1997, to conventionally squeeze cement the lower thief zone (4709'-4726') below a retainer at 4701' and then squeeze cement the upper perforations at 4568'-4582'. After three attempts to squeeze the upper zone, the well pressure-tested in the upper zone and the well was placed back on water injection.

A subsequent water injection profile survey was run during June, 1997, which indicated the upward channel had successfully been plugged; however, virtually one-hundred percent (100%) of the injected water was now going out the bottom of the well. A foamed cement job was then performed during late June to stop the out-of-zone injection, and the well was reperforated across the E and upper F zones (4618'-4638'). The job appeared to have been successful as planned, and the well was then placed on CO_2 injection.[6]

On September 19, 1997, a follow-up injection profile was obtained on the well, at a reported injection rate of 424 barrels of water per day (BWPD) at 400 pounds per square inch gauge (psig) surface injection pressure. The velocity calculations indicated that eighty-three percent (83%) of the fluid was going into the new perforations at 4618'-4638'; however, eighteen percent (18%) of the fluid was exiting the old perforations at 4631'-4637'. No flow was detected inside the pipe past 4642'.

The temperature logs indicated channeling up to 4580' and a channel down below 4648', with approximately seventy percent (70%) of the fluids leaving in the new perforations at 4618'-4628'. Based on the results of this survey, the foamed cement job was not considered a success. However, the well was placed back on CO2 injection pending further evaluation.

SCU Well No. 6-27W

The initial injection log run on Well No. 6-27W indicated 50-60% of the injection volume was leaving the wellbore through the perforated interval 4746'-4748', which had been perforated below the oil-water-contact at approximately -1800' subsea (ss). The injection survey also indicated limited water injection occurring above 4686'.[7]

A foamed cement squeeze was performed on Well No. 6-27W in early August, 1997, utilizing 300 sacks of "premium plus" cement foamed with 10 pound/gallon density. The cement was then drilled out, and the well was reperforated at 4608'-4628'. The well was stimulated, and placed back on water injection. A follow-up injection profile survey was run during mid-September to determine the effectiveness of the foamed cement squeeze.

The velocity shots indicated 82% of the fluid leaving in the new perforated interval 4608'-4628', with 18% exiting the old perfs at 4631'-4635' and no flow inside the pipe past 4642'. The temperatures indicated 70% loss through the new perforated interval, with 6% movement down to 4648' and an upward channel to 4580' (not out of the San Andres interval). Although not perfect, the profile indicated a correction of the out-of-zone injection, and the well was placed on CO_2 injection shortly thereafter.

SCU No. 6-28W

During the drilling of vertical WAG injection Well 6-28W, oil shows were seen in the drilling returns; however, when placed on a production test during late January, the well produced 70% CO_2 cut in the produced gas. This gave concern that CO_2 was by-passing contact with reservoir rock through the suspected fracture in the toe region of the northwesterly horizontal WAG injection Well 7C-11H. In order to test this hypothesis, a tracer test was attempted between the two wells.

On February 25, 1997, a sulfur hexaflouride (SF_6) tracer test was run on WAG injection Well 7C-11H, with produced gas samples being pulled from Well 6-28W. A trace of tracer gas was found in Well 6-28W within nine (9) hours of injection; however, no additional SF_6 tracer was encountered upon subsequent monitoring. Although first results seemed to confirm that a direct channel exists from the horizontal injector to Well 6-28W, further investigation of the sampling techniques indicate that the sampling may have been tainted, rendering the test results inconclusive. Further tracer and/or fluorescent dye testing is planned for 1998 to further delineate remediation possibilities.[8]

The injection survey run on this well during March, 1997, while on water injection, indicated a serious channel out the bottom perforations of the well below lowest total depth. This was not surprising considering the CO_2 production history of the well. A series of foamed cement squeezes were performed on the well during late August and early September to remedy the out-of zone injection. Although a total of over 700 sacks of cement were ultimately pumped into the well, and new perforations shot from 4650'-4650', when placed on production test the well produced 2.8 BOPD, 22 BWPD, and 37 MCFGD (99% CO_2), indicating the channel had not been successfully squeezed. It is believed that the high pressure CO_2 channel did not allow the cement to remain static and set-up sufficiently to contain the flow. Because further work is still required on the profile, the well was placed back on water injection, and a pulse test is planned for early 1998 to determine the source of the high pressure CO_2.

FRACTURE PRESSURE ANALYSIS

During the reservoir characterization work on the project, reservoir characterization Wells Nos. 6-23 and 6-21 were drilled, tested, and completed as producers.

Well 6-23 was spudded July 13, 1994 and drilled to a total depth (TD) of 4900 feet. A microfracture test was conducted which determined the formation parting pressure to be 2608 psig at that time, equivalent to .55 psi/ft. fracture gradient. An acoustic borehole imaging log showed the top of the fracture at 4680', within the basal 20 feet of the reservoir interval (D zone), and continuing downward to the base of the well. The fracture appeared to initiate in the oolitic grainstone in Zone A, at 4790'.[9]

Well 6-21 was spudded July 16, 1994 and drilled to a total depth of 4900 feet. A microfracture fracture test was conducted with the well at 4776', before penetrating the A zone. The fracture initiation pressure in this test was 2727 psig, equivalent to a .58 psi/ft fracture gradient. The acoustic imaging log was not logged below 4735' because of an obstruction in the wellbore, but showed the fracture to extend from 4699' down below the log total depth (LTD). Following the microfracture test, drilling was resumed to total depth.[10]

As previously mentioned, a step rate test was also run on horizontal injection well 7C-11H, which showed a shift towards linear (fracture) flow behavior and possible fracture extension above 2600 psig bottomhole injection pressure.

A review of the instantaneous shut-down pressures obtained during recent wellwork confirmed the conclusion that the fracture gradient is approximately .58-.60 psi/ft.

UPDATE PERFORMANCE PREDICTIONS/RE-EVALUATE DESIGN PREMISES

The South Cowden full-field simulation model was updated to incorporate the exact project development and operating schedule as implemented during the first 12 months of project operations. The original simulation model was adjusted to reflect the details of the actual locations, completions, and timing of newly drilled, reactivated, and recompleted wells in the CO_2 flood project area. No additional history matching changes were made to the simulation model reservoir description used in making the original project forecasts.

Figure 6 shows a comparison of actual Unit performance versus (vs.) model forecast performance under both the originally premised project operation and implementation schedule and under the actual project operations and implementation schedule. The original project implementation schedule premised all new drilling, well work, facilities upgrades, etc. for the project would be completed by the premised July 1, 1996, CO_2 injection start date for the project. While all new wells were drilled and completed as scheduled, the actual startup of injection and production operations was delayed in some wells due to well testing, conducting profile surveys, etc. Also, reactivation of several shut-in producers was delayed several months compared with the premised implementation plan due to logistical considerations. The productive capacity of several reactivated production wells was initially significantly less than was premised in the original forecasts (based on the capacity of each well prior to shut-in). These variances in project operations and the delays in the project implementation schedule compared with the originally premised development plan had an unexpectedly large impact on the first twelve months CO_2 flood response.

Figure 7 shows the simulation model forecast gas injection rates in comparison with the actual measured CO_2 injection rates during the first year of project operations. The actual and forecast rates agree fairly well, however the actual injection schedule lagged the premised forecast by about three months. Figure 8 shows a comparison of forecast vs. actual injection rates for the individual CO_2 injection wells in the project in the first quarter of 1997. The relative injection rates of the two horizontal wells can be compared with injection rates into the two vertical wells. One of the horizontal wells (7C-11H) was rate constrained to 3.5 MMscfd during this period because most of the injected fluid was seen leaving the horizontal section through one short interval, indicating a probable fracture or thief zone at this point. Subsequent falloff testing and injection profile surveys indicated that there was a possible fracture at this point in the horizontal Well 7C-11H.

Based on the results of model forecasts vs. actual field performance, individual well responses, and injection profile data, remedial actions were recommended to remedy suspected problems with injection profiles and inadequate production capacity in certain wells. Specific recommendations were implemented during the summer of 1997 to stimulate selected production wells. Recommendations were made on wellhead injection pressures to better maintain injection within the target interval, and plans are being formulated to provide for water disposal outside of the San Andres reservoir towards reducing the overall system pressure. Additional conformance work is planned to improve injection profiles in the CO_2 injection wells, particularly in the SCU horizontal injection Well 7C-11H.

As more data become available on the CO_2 production response in the South Cowden reservoir, further adjustments will be made to the simulation model reservoir description to match field performance and the CO_2 flood forecasts will be updated periodically. Based on these results, some adjustment of the reservoir management program may be advisable at South Cowden to optimize performance of the CO_2 project.

INCREASE PRODUCTION/THROUGHPUT

During second and third quarter 1997, seventeen wells were acid stimulated utilizing a sonic hammer device. This was done in order to minimize required pump-in pressures. The results follow of these clean-outs are summarized in Table 2.

Production for the project area was increased by approximately 75 barrels of oil per day (BOPD) and 1500 barrels of water per day (BWPD) as a result of the total clean-out program.

In addition to stimulation work in the project area, the project team is currently evaluating the application of horizontal lateral drilling technology from existing production wells to increase the overall throughput within the reservoir. The original reservoir simulation model was built assuming the wells would produce at peak rates similar to those seen during waterflooding; however, actual production is considerably lower than originally anticipated and additional throughput may be required to get efficient movement of the injectant through the reservoir.

REDUCE INJECTION PRESSURES

After reviewing the results of the injection profile surveys, and the current injection rates and pressures, a decision was made in December, 1997, to reduce the injection pressures within the Unit area to 650 psig surface pressure while on water injection, and 1150 psig surface pressure while on CO_2 injection. It was recognized that this would result in a decrease (perhaps a significant decrease) in CO_2 volumes. The 1150 psig wellhead pressure with an estimated 0.35 psi/ft CO_2 column was determined to be equivalent to a bottom-hole injection pressure of approximately 2800 psig at -1700 subsea (ss), or approximately 100 psig below the estimated parting pressure.

Once the reservoir injection has stabilized below the calculated parting pressure, an extensive program of step rate testing is planned across the project area to determine specific parting pressures across the field. It is believed that as long as we continue to inject above parting pressure, out-of-zone losses seen on the injection profiles are inevitable.

REDUCE RESERVOIR PRESSURE

The reservoir pressure at South Cowden Unit is estimated currently at 2300 psig, while minimum miscibility pressure is approximately 1200 psig. In order to improve the sweep and recovery efficiency of the CO_2 WAG project, a decision was made to make provisions for disposal of produced water outside of the San Andres reservoir in order to begin reducing the total system pressure.

A review of existing production in the South Cowden field was made in order to determine the existence of possible depleted reservoirs in close proximity of the Unit. There has been limited production in the Ellenburger (13,000'); however, substantial oil volumes have been recovered from the Canyon (9500') sand immediately to the north and east of the Unit area. The Canyon reservoir is a highly-fractured solution gas drive oil reservoir, which has been drilled-up on 40-acre spacing and marginally waterflooded. Success under secondary recovery is limited due to the fractured nature of the carbonate formation, as the sweep efficiency is limited, with water injection being used primarily to maintain reservoir pressure.

SCU Well No. 2-18, formerly the Standard of Texas - H.C. Foster Unit No. 1, was drilled as a Devonian/Ellenburger exploration well in 1966. On drill stem testing (DST), the Ellenburger was determined to be water-bearing. After logging, Forrest Oil assumed operatorship of the well, and completed it in the Devonian. That completion was acidized and fracture treated, but tested dry.

The 5-1/2" casing was cut and pulled, and the well was plugged and abandoned (P&A'ed). The well was sold to the Unit as a replacement well for SCU Well No. 2-03, and was reentered and completed in the unitized San Andres interval. The well was then temporarily abandoned following a non-commercial San Andres test.

Plans are being implemented to deepen this well to 9500' for use as a disposal well in either the Cisco/Canyon (9500') or Clearfork intervals (6500'). It is anticipated that disposal capacity of approximately 5000 BWPD will be required in order to reduce the overall system pressure at a reasonable rate.

CONTINUE CONFORMANCE CONTROL

The project team is currently evaluating a number of alternatives for remediation of the injection profile problems in the CO_2 WAG wells. However, reductions in the reservoir pressures are seen as essential prior to doing substantial profile conformance modification work. An overall reservoir pressure reduction will allow for increased injection rates while remaining below the parting pressure.

Alternatives for correcting the injection problem in the toe of horizontal injection Well No. 7C-11H include the use of mechanical or chemical permanent isolation devices; the application of cross-linked polymers, monomers, neat cement, or foamed-cement; or the use of low-cost temporary solutions such as sodium silicate or oyster shells. The project team is currently in the process of evaluating all these alternatives, recognizing that out-of-zone injection in this well can be detrimental to the success of the entire project.

Similar alternatives will be reviewed for required corrections in the Tract 2 vertical WAG injection wells, although these may not be required after the system pressure is reduced and larger volumes can be injected under the parting pressure.

CONCLUSIONS

1) The injection profile in the east-west horizontal injection Well No. 6C-25H is good, with injection occurring in approximately 250' of the horizontal section. Oil response in wells immediately to the south of this well indicate good placement. However, early CO_2 breakthrough in the C zone of Well 6-22 suggests vertical movement of the CO_2 within the reservoir.

2) The injection profile in the northwesterly horizontal Well No. 7C-11H is poor, with injection occurring in approximately 40' in the toe of the horizontal section. Fall-off and step-rate testing in this well show linear flow near the wellbore, indicating possible flow through an intersected fracture. Early breakthrough of CO_2 in the lower San Andres zones (A through C) in Wells Nos. 7-03W and 7-05 would suggest the fracture intersects these high permeability/water-bearing layers beneath the target E zone.

3) Overall throughput in the reservoir is lower than originally modeled based on actual well performance during waterflood operations. The production wells have all been stimulated, and the application of horizontal production laterals is being evaluated to increase overall production.

4) CO_2 injection in the vertical WAG injection wells has exceeded parting pressure, thus increasing the problem with out-of-zone injection. Bottomhole injection pressures are being monitored to ensure injection pressures are maintained below the parting pressures. Purchased CO_2 volumes have been reduced to minimum contract quantities (approximately 6 MMscfd) while reservoir pressures are being reduced.

5) The overall reservoir pressure needs to be reduced by at least 300 psi to increase sweep and recovery efficiencies. SCU Well 2-18 will be deepened for use as a disposal well within the Cisco/Canyon or Clearfork intervals. Disposal capacity of at least 5000 BWPD is required for timely reduction of reservoir pressure.

6) Various temporary and permanent methods of profile modification are being considered for application in horizontal WAG injection Well No. 7C-11H, where fracture flow is suspected. Profile modification work on the Tract 2 vertical injectors, Nos. 2-26W and 2-27W, will be delayed until after the reservoir pressure has been reduced and higher CO_2 volumes can be injected without exceeding the formation parting pressure. Further conformance control work on leaseline injector SCU 6-28W will also be delayed until such time the CO_2 source can be identified and the channel remedied.

NOMENCLATURE

OOIP	=	Original oil in place
BOPD	=	Barrels of oil per day
BWPD	=	Barrels of water per day
MCFD	=	Thousands of cubic feet per day
MMscfd	=	Millions of standard cubic feet per day
Mscfd	=	Thousands of standard cubic feet per day
MMSTBO	=	Millions of stock tank barrels of oil
CO_2	=	Carbon dioxide
WAG	=	Water-alternating-gas
md	=	Millidarcy
ppf	=	Pounds per foot
WL	=	Wireline measured depth
LTD	=	Logged total depth
psi	=	Pounds per square inch
psig	=	Pounds per square inch (Gauge measure)
ft	=	foot
ss	=	subsea
DST	=	Drill stem test
P&A	=	Plug and abandon

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9,10 Hallenbeck, L.D., K.J. Harpole, and M.G. Gerard, "Design and Implementation of a CO2 Flood Utilizing Advanced Reservoir Characterization and Horizontal Injection wells in a Shallow Shelf Carbonate Approaching Waterflood Depletion," Annual Report for the period of June 3, 1994-October 31, 1995, Performed Under Contract No. DE-FC22-94BC14991, Bartlesville Project Office, U.S. Department of Energy, May 1996, Bartlesville, Oklahoma, p. 8.

Table 1
South Cowden Unit
Reservoir Data

Working Interest	86.79
Producing Formation	San Andres Dolomite
Area	2050 acres
Datum Depth	4550'
Average Porosity	12%
Average Permeability	3.7 md
Permeability Variation (Cores)	.65
Reservoir Temperature	96 degrees F @ datum
Irreducible Water Saturation	30%
ST Oil Gravity, Degrees API	36
Oil Volume Factor at 325 psi	1.089
Oil viscosity at 86 degrees F and 325 psi	2.92 cp
Water viscosity at 96 degrees F	0.71
Initial Reservoir Pressure	1700 psig
Reservoir pressure at start of WF	400 psig
Saturation Pressure	325 psig @ reservoir temperature
Original Oil in Place	100 MMSTBO
Primary Production	10.0 MMSTBO
Secondary Production	25.4 MMSTBO
Recovery Factor	35%
Current Oil Production	500 BOPD
Producing Watercut	93%
Water Injection Rate	8000 BWPD
Project Area	1000 acres
Planned CO2 Injection	35 Bscf
Expected Recovery	10.0 MMSTBO
Project Recovery Factor	15%

Table 2
1997 Acid Stimulation Results

	BEFORE			AFTER		
Well	BOPD	BWPD	MCFD	BOPD	BWPD	MCFD
SCU 2-01	20	107	0	41	217	7
SCU 2-02	3	41	0	12	188	1
SCU 2-08	3	38	0	13	147	3
SCU 2-22	8	141	5	24	253	29
SCU 2-25	30	167	5	30	207	6
SCU 5-07	8	87	1	25	225	49
SCU 6-02	12	105	1	9	150	47
SCU 6-22	47	97	25	0	151	32
SCU 7-02	2	43	0	11	70	28
SCU 7-08	28	910	340	20	477	123
SCU 7-09	3	55	0	5	220	0
SCU 7-12	1	8	0	0	285	0
SCU 7-13	14	30	0	9	1	5
SCU 7-15	6	30	0	13	96	0
SCU 7-01	24	116	116	31	170	100
SCU 7-05	4	212	1	5	385	1
SCU 7-10	3	62	6	17	116	26

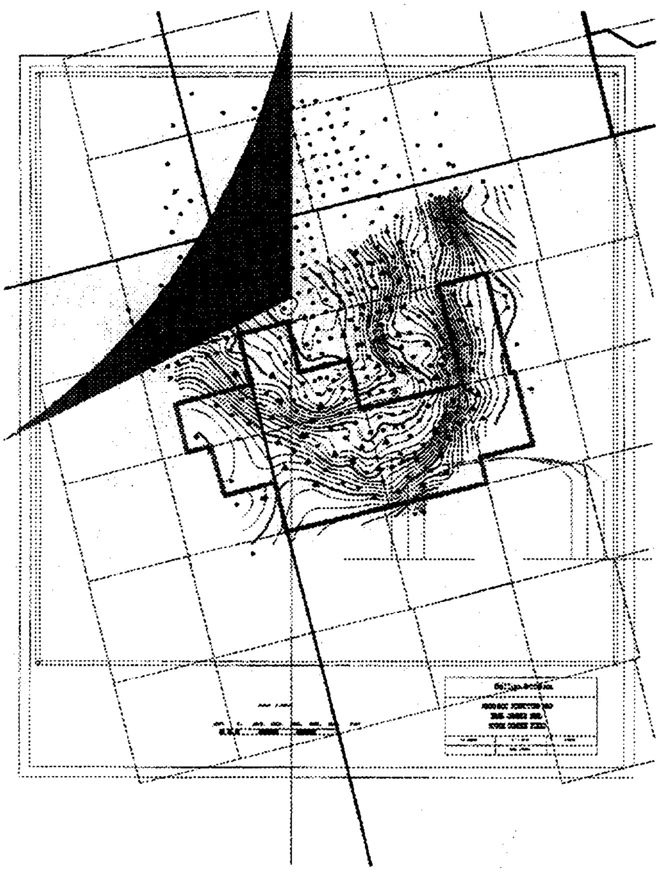

Figure 1 - Base of Cowden Sand

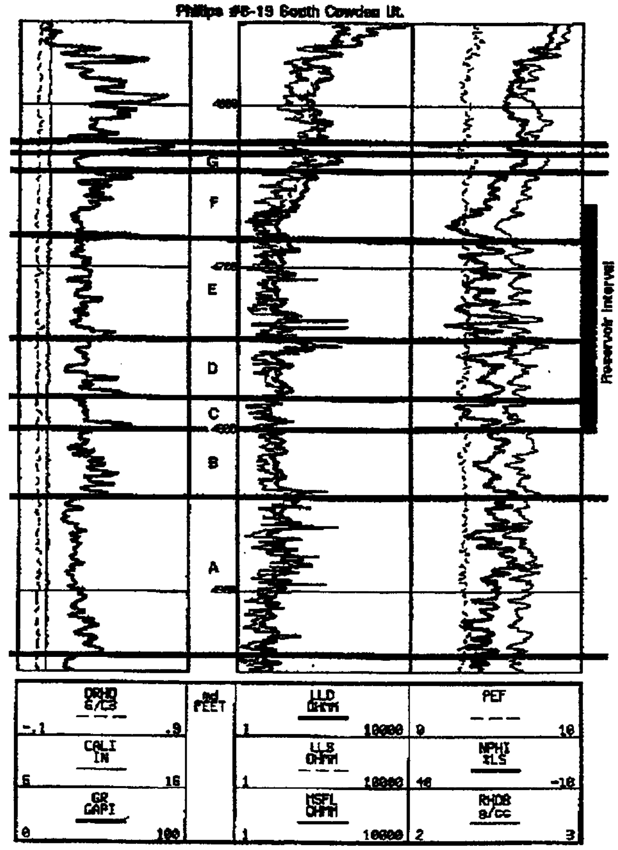

Figure 2

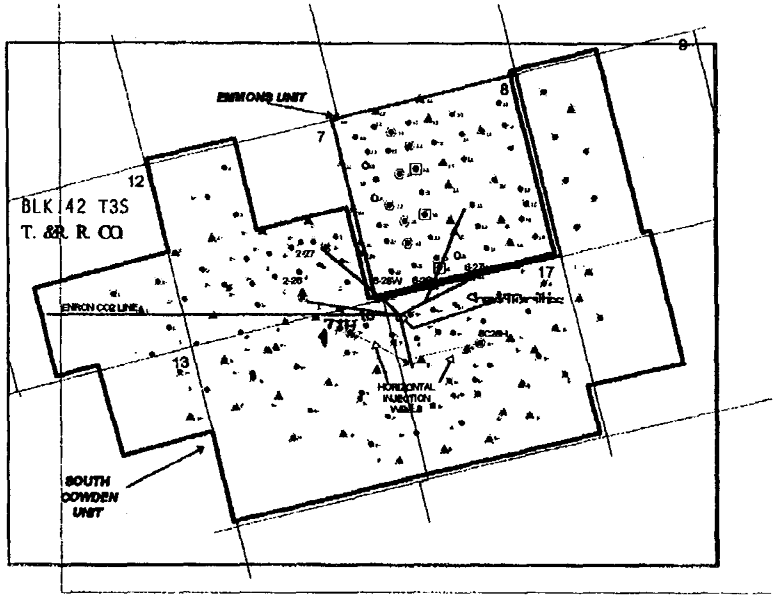

Figure 3 - Unit Map with Injection Wells and Shared Facilities Noted

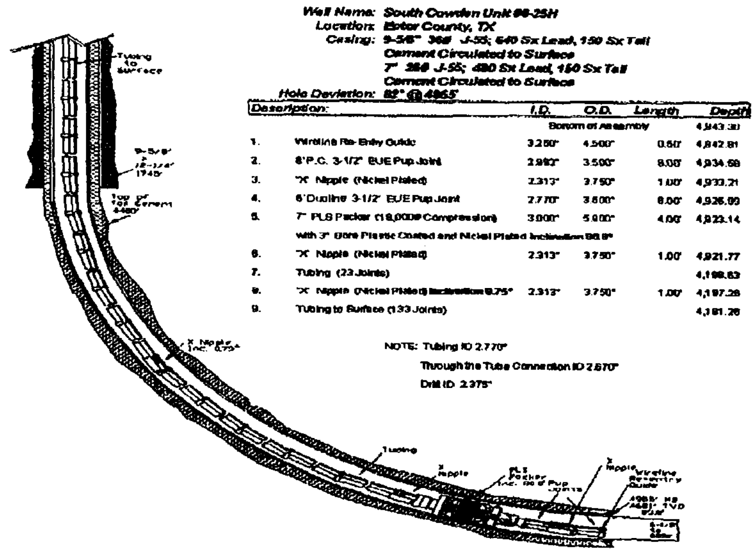

Figure 4 - Wellbore Schematic for Horizontal Injection Well 6C-25H

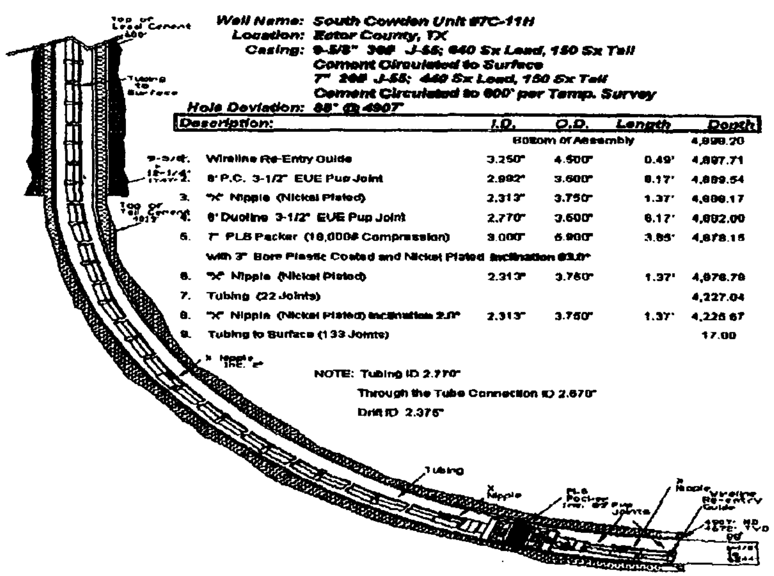

Figure 5 - Wellbore Schematic for Horizontal Well 7C-11H

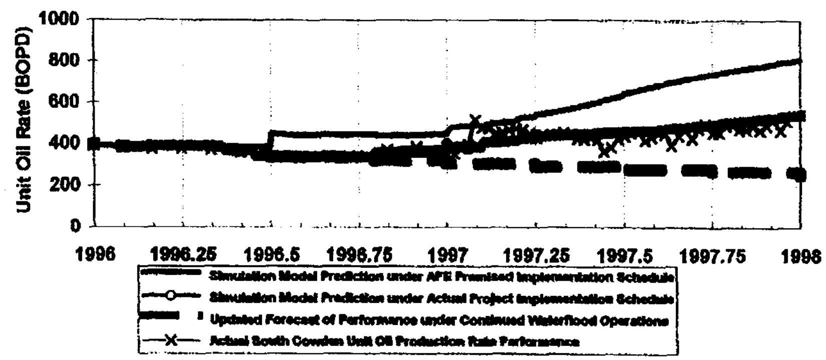

Figure 6 - South Cowden Unit
Actual vs. Forecast CO2 Project Performance

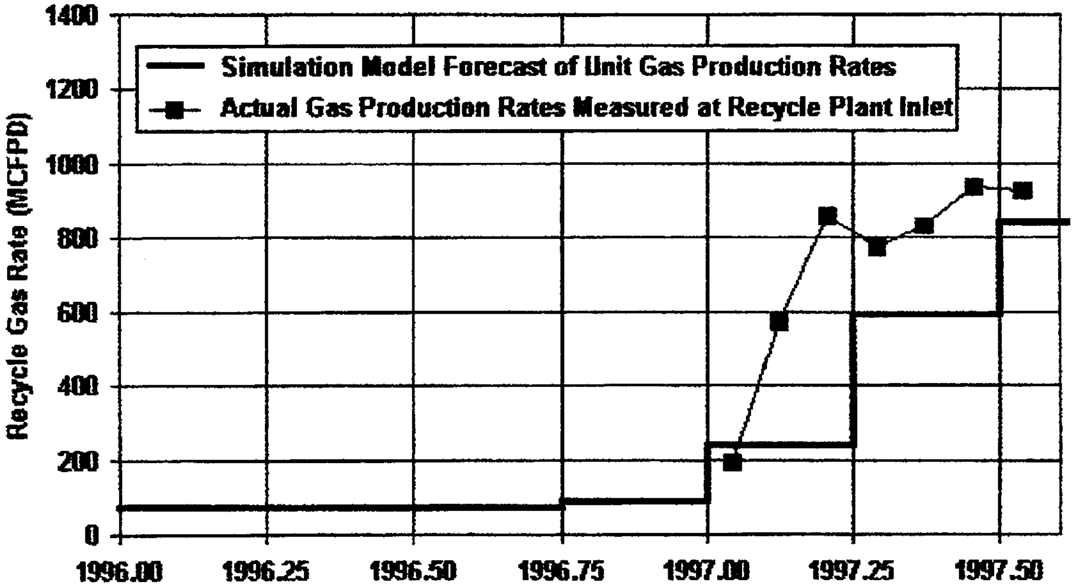

Figure7 - South Cowden Unit
Actual vs. Forecast CO2 Project Gas Production Performance

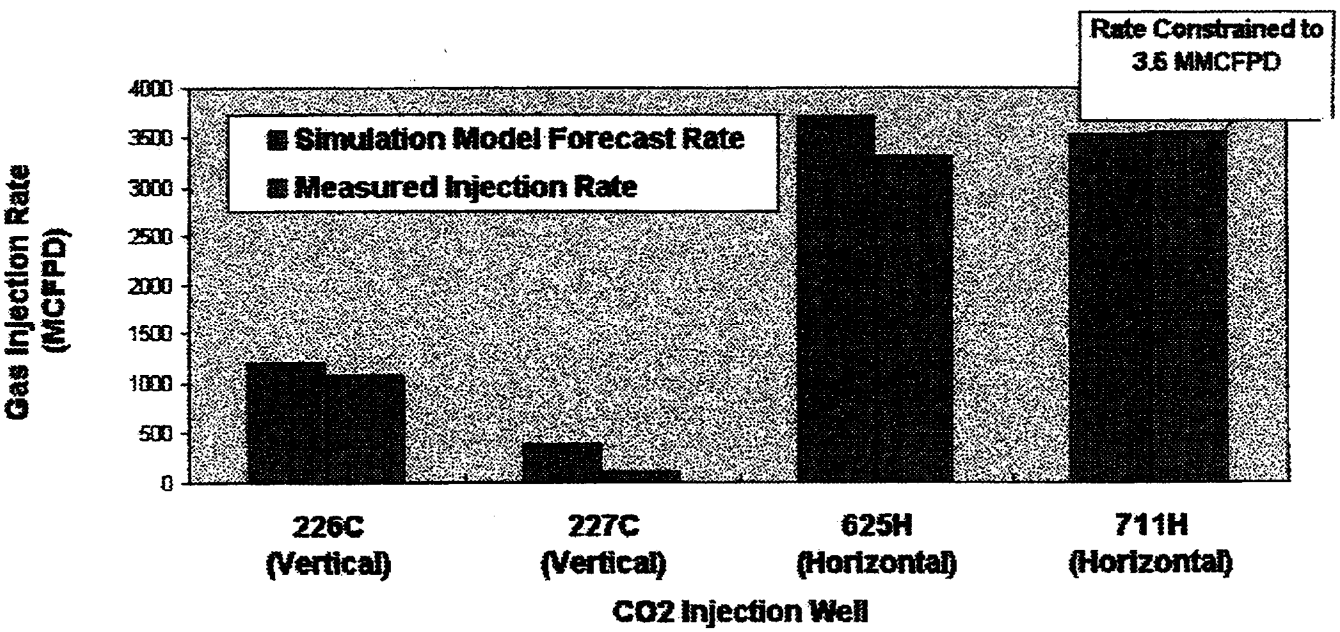

Figure 8 - Model Forecast vs. Actual CO2 Injection Rates SCU Project Wells - First Quarter 1997