DESIGN AND IMPLEMENTATION OF A CO₂ FLOOD UTILIZING
ADVANCED RESERVOIR CHARACTERIZATION AND HORIZONTAL
INJECTION WELLS IN A SHALLOW SHELF CARBONATE
APPROACHING WATERFLOOD DEPLETION

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ABSTRACT

Work reported in this document covers tasks in Budget Phase II. The principle task in Budget Phase II is Field Demonstration.

Since starting carbon dioxide (CO₂) injection in July 1996, several operationally related issues emerged within this reporting period. These include out of zone CO₂ injection, conformance methods, high reservoir pressure, and lack of injectivity and productivity.

The under-performance is related to:

- 1) “Out of zone” CO₂ injection.
- 2) Through-wellbore communication of abandoned wells.
- 3) Productivity and injectivity of wells.

To resolve these issues a redevelopment scheme was initiated in early 2000 after several discussions with the Department Of Energy.

The redevelopment centered around short radius lateral drilling and selective stimulation in the upper San Andres and was determined to be the optimum redevelopment scheme to improve the CO₂ flood. The optimum development with regard to recovery and economics follows a two phased approach.

Redevelopment PHASE I – Test lateral technology, improve offtake in center of CO₂ flood.

Redevelopment PHASE II – Improve in zone injection and reduce reservoir pressure

INTRODUCTION

Summary of Project Objectives

The principle objective of this project is to demonstrate the economic viability and widespread applicability of an innovative reservoir management and carbon dioxide (CO₂) flood project development approach for improving CO₂ flood project economics in shallow shelf carbonate (SSC) reservoirs.

Most of the incremental tertiary oil production from CO₂ projects in SSC reservoirs to date has come from a few, very large-scale projects where the sizable economies of scale inherent in this type of development can greatly improve project economics. In fact, the five largest CO₂ miscible flood projects implemented in SSC reservoirs account for over one-half of the total incremental oil production attributable to CO₂ miscible flooding in 1992 in the United States.

This project shall demonstrate the economic viability of the advanced technology of developing a CO₂ flood project utilizing multiple horizontal CO₂ injection wells drilled in several directions from a central location. The use of several horizontal injection wells drilled from a centralized location will reduce the number and cost of new injection wells, wellheads, and equipment; allow concentration of the surface reinjection facilities; and minimize the costs associated with CO₂ distribution system. It is anticipated that the proposed advanced technology will show improved CO₂ sweep efficiency and will significantly reduce the capital investment required to implement a CO₂ tertiary recovery project relative to conventional CO₂ flood pattern developments using vertical injection wells. This technology will be readily transferred to the domestic oil industry and should introduce CO₂ flooding as an economically viable technology option for smaller SSC reservoirs and for independent operators.

Summary of Field Details

The South Cowden Unit (SCU) is located in Ector County, Texas and produces primarily from the Grayburg and San Andres Formations of Permian Age. These formations were deposited in shallow carbonate shelf environments along the eastern margin of the Central Basin Platform. The primary target for CO₂ flood development under the proposed project is a 150-200 foot gross interval within the San Andres located at an average depth of approximately 4550 feet. The original oil in place (OOIP) for the South Cowden Unit is estimated to be less than 180 million barrels. The field was discovered in 1940 and unitized for secondary recovery operations beginning in 1965.

After approximately 60 months of CO₂ injection, the Unit is producing 718 barrels of oil per day (BOPD) with a water cut of 91% from 47 active producers and 12 active injectors. For June 2001, the continued water injection prediction for oil rate, if no further development had occurred at South Cowden, is zero BOPD. This is because the lease was predicted to be uneconomic at this date, so 718 BOPD of incremental production is deemed to be the result of

the implementation of the additional South Cowden development. Ultimate recovery for primary plus secondary was estimated at the start of the project at just over 35 million stock-tank barrels of oil (STBO), or approximately 20 percent of original oil in place (OOIP). Tertiary oil resulting from the CO₂ project was estimated at 12 million stock-tank barrels (STB), or 8% within the project area.

Project Description

The purpose of this project is to demonstrate the economic viability and widespread applicability of an innovative management plan for a CO₂ flood project, utilizing advanced reservoir characterization and CO₂ horizontal injection wells. The South Cowden Unit (SCU) is an example of a very mature waterflood, rapidly approaching its economic limit. Past waterflood performance was considered good; however, field average water cut at the project start-up exceeded 95 percent, leaving tertiary recovery as the only remaining prospect for extending the field life and recovering the remaining oil. Advanced reservoir characterization has been used to define the best areas within the field, which are likely to perform well under CO₂ operations.

Standard methods of CO₂ flooding are not viable under the current oil price scenario due to the limited aerial extent of SCU. Standard methods include the traditional fully confined nine- or five-spot patterns. In the case of SCU, a feasibility study was completed in which the field was CO₂ flooded with 20-acre five-spots (assumed because of the existing well configuration). The feasibility study indicated that South Cowden Unit was an excellent technical CO₂ flood candidate; however, the large capital investment required restricted its economic viability. New and innovative methods were required to reduce the overall investment required to improve the economic viability. These new methods, however, carried additional risk.

The innovative approach chosen for the study was to CO₂ flood the South Cowden Unit with multiple horizontal injection wells from a centralized location. Preliminary studies indicated that significant investment cost reduction could be realized through lower overall drilling costs (fewer wells) and reduced surface injection line requirements, and operating costs reductions could be obtained through a reduction in re-injection costs. Improved sweep efficiency from the horizontal injection wells are expected to result in increased oil recoveries. Increased technical risks inherent in the project include the injection distribution along the horizontal section of the horizontal well and overall vertical coverage within the given horizontal well. Contingency plans for dealing with the technical risks were also developed. Advanced reservoir characterization has been essential in optimizing the final project design.

EXECUTIVE SUMMARY

In June of 1994, Phillips Petroleum Company received a financial award from the Department of Energy (DOE) to conduct a project in the South Cowden Unit (SCU) in Ector County, Texas. The project purpose is to design an optimum carbon dioxide (CO₂) flood project utilizing advanced reservoir characterization and CO₂ horizontal injection wells, demonstrate the performance of this project in the field and transfer the information to the public so it can be used to avoid premature abandonment of other fields.

The producibility problem in the unit is that it is a mature waterflood with a water cut exceeding 95%. Oil must be mobilized through the use of a miscible or near-miscible fluid in order to recover significant additional reserves. Also, because the unit is relatively small, it does not have the benefit of economies of scale inherent in the very large-scale projects, which have historically produced most of the CO₂ project oil. Thus, new and innovative methods are required to reduce the investment and operating costs.

Two primary methods to be used in this work to accomplish improved economics are the use of reservoir characterization to restrict the flood to the high quality rock in the unit and the use of horizontal injection wells to cut investment and operating costs through centralization.

The project consists of two budget phases. Budget Phase I started in June 1994 and ended late June 1996. During this phase the Reservoir Analysis and Characterization Task and the Advanced Technology Definition Task were completed. Completion of these tasks enabled the project to be designed, evaluated, and an Authority for Expenditure (AFE) for project implementation to be generated and submitted to the working interest owners for approval. Budget Phase II consists of the implementation and execution of the project in the field. Phase II terminated July 2, 2001.

Budget Phase II commenced with the drilling of the third reservoir characterization well (RC-3) during November and December 1995. Two vertical CO₂ water alternating gas (WAG) injection wells were drilled in December 1995. Two horizontal CO₂ WAG injection wells were drilled and completed during March and April 1996. These wells were designed to mechanically optimize well injection performance and useful well life. Two additional production wells were also drilled and completed in late 1995. These wells were needed to drain areas of the field offsetting the proposed horizontal injection wells, replacing old wells that had been previously plugged and abandoned.

Additional early Budget Phase II work commenced during the first half of 1996 included petrographic core studies on specific cores obtained during the drilling of the third Reservoir Characterization Well (RC-3).

Budget Phase II work continued with initiation of CO₂ injection in the two vertical WAG injection wells during July 1996, and the two horizontal WAG injection wells in August 1996, at a rate of approximately 8.0 million standard cubic feet per day (MMSCFD) within the SCU project area. Three additional lease-line WAG injection wells were drilled and completed along

the north boundary with the Emmons Unit. Injection profile problems were identified during early 1997 in two of these wells. Subsequent foamed cement isolation techniques during 1997 reduced out-of zone injection in these wells.

Two additional production wells, 7-13 and 7-15, were drilled during 1996. The first well as a replacement well and the second well was to tighten well spacing in an important area of the Unit. An additional replacement well No. 6-29 was drilled in September 1997, to replace well No. 6-01, which had irreparable casing damage. Two shut in producing wells, 6-18 and 8-03, were converted to water injection during third quarter 1997. Three wells, 2-16W, 6-01 and 6-12, were plugged and abandoned due to regulatory requirements associated with bad casing.

Interference tests between wells 7C-11H, 6-28 and 2-26 during October 1997 indicated over communication, due to fracturing, between wells 6-28 and 2-26. A subsequent test during June 1998 indicated little or no communication between these wells.

Performance monitoring identified the majority of producing wells are underperforming their anticipated withdrawal rates. Although acid stimulations during 1997 improved productivity, but they were somewhat short-lived. A longer-term solution was needed.

High reservoir pressure is a concern for the project as it has limited CO₂ injectivity. To lower reservoir pressure, improving withdrawal rates has become of utmost priority with various solutions evaluated: chemical treatments, perforations, stimulation and horizontal lateral technology. A disposal well was needed for excess produced water. Well 2-18 was therefore drilled as a water disposal well by deepening to the Canyon and Clearfork intervals. Graph 1 shows historical injection rates and surface pressures for this well.

CO₂ injection pressures were cut back in late 1997 to reduce pressures below fracture initiation pressure. It was believed significant out of zone injection was caused by the initial overpressuring during the early months of injection. Technologies were evaluated to ensure both in-zone injection and improvement of injectivity to ensure CO₂ volumes are being efficiently utilized.

Cumulative CO₂ injected as of June 2001 is 10.8 BCF. The average daily CO₂ injection rate during June 2001 was 7.8 MMscf CO₂ per day.

After discussion internally within Phillips, externally with Department of Energy and SCU partners a redevelopment of South Cowden was agreed upon to commence in year 2000. The redevelopment of South Cowden centered around short radius lateral drilling and selective stimulation in the upper San Andres. The two redevelopment phases agreed upon were:

Redevelopment PHASE I – Test lateral technology, improve offtake in center of CO₂ flood. Four existing vertical producing wells (7-13, 6-23, 6-20, 6-22) were isolated from their existing completions and successfully side-tracked with horizontal laterals into the upper layers of the San Andres as planned. This work was completed during May 2000.

Redevelopment PHASE II – Improve in zone injection and reduce reservoir pressure.

Five existing vertical CO₂ injection wells (2-26, 2-27, 6-26, 6-27, 6-28) were isolated from their existing completions and successfully side-tracked with horizontal laterals into the upper layers of the San Andres as planned. Well 2-27 has a single lateral; all others have dual laterals. Four existing vertical producers (2-20, 2-25, 6-21, and 7-15) were successfully side-tracked with single horizontal laterals into the upper layers of the San Andres as planned. This work was completed during April 2001.

Results to date have been mixed. Oil production rates from these eight horizontal producers have increased from 86 BOPD in January 2000 to 321 BOPD in June 2001, but CO₂ injection is less than planned in wells 2-26, 2-27, and 6-27. Total production rate from 2-20 has been poor, averaging less than 40 barrels of liquid per day (BLPD) in June 2001. South Cowden Unit production has increased from 491 BOPD in June 2000 to 718 BOPD in June 2001. Unit gas production has increased from 1,649 thousand cubic feet per day (MCFD) in June 2000 to 2,692 MCFD in June 2001.

EXPERIMENTAL

None.

RESULTS AND DISCUSSION

Background Information and Redevelopment Plans Summary

Budget Phase Two consists of Tasks V-VI as defined in the Revised Statement of Work (RSOW) dated March 8, 1996. The original Statement of Work (SOW) contained fourteen primary subtasks in Task V and five primary subtasks in Task VI, including Technology Transfer, Reporting, and Project Management Activities related to Budget Phase Two. Monitoring of the project performance from 1996 to 1999 suggested the flood was under-performing original forecasts. The under-performance was related to:

- 1) “Out of zone” CO₂ injection.
- 2) Through-wellbore communication of abandoned wells.
- 3) Productivity and injectivity of wells.

The major keys to redeveloping South Cowden are as follows:

- 1) Develop a method to improve productivity and injectivity without allowing communication to lower San Andres intervals
- 2) Reduce overall reservoir pressure to improve CO₂ injectivity.
- 3) Ensure productivity & injectivity can be maintained throughout the remainder of field life.

A redevelopment of South Cowden centered around short radius lateral drilling and selective stimulation in the upper San Andres was determined to be the optimum redevelopment scheme to improve the CO₂ flood. The optimum development with regard to recovery and economics follows a two phased approach.

PHASE I – Test lateral technology, improve offset in center of CO₂ flood.

PHASE II – Improve in zone injection and reduce reservoir pressure.

The phased approach was used to determine that short radius lateral drilling could be implemented effectively at South Cowden. Additional subtasks V.15 through V.17.5 were added on February 21, 2000 to improve the CO₂ flood.

TASK V: FIELD DEMONSTRATION

Recycle Compression Facilities

The CO₂ recycle compression facilities have been in continuous operation. The compressor capacity was upgraded from 1.2 MMSCF/D to 4.5 MMSCF/D.

Drill Four Lateral Producers (Redevelopment Phase1)

Four existing vertical producing wells (7-13, 6-23, 6-20, 6-22) were isolated from their existing completions and successfully side-tracked with horizontal laterals into the upper layers of the San Andres as planned. This work was completed during May 2000.

Upgrade Disposal Well (Redevelopment Phase 2)

No action was taken during the reporting period on this sub task. Well SCU 2-18 is in service and is meeting the needs of the unit for water disposal.

Drill Five Laterals in Existing Vertical CO₂ Injectors (Redevelopment Phase 2A)

Five existing vertical CO₂ injection wells (2-26, 2-27, 6-26, 6-27, 6-28) were isolated from their existing completions and successfully side-tracked with horizontal laterals into the upper layers of the San Andres as planned. Well 2-27 has a single lateral; all others have dual laterals.

The Scientific Drilling system was used to drill all Phase 2A and 2B horizontal wellbores. The Scientific system is a four-stage process. Once the well is prepared a whipstock is installed, the casing is milled, and then the curved section drilled with a mud motor. Finally the lateral section is drilled with a mud motor. Surveying is performed using a measurement while drilling (MWD) tool, typically taking 15 seconds to survey. Any corrections to direction are performed downhole. The obvious advantages of this system are that frequent surveying is possible and corrections to direction do not require the bottom hole assembly to be removed. The drawback with the system is the potential for “lost in hole” charges if expensive tools become stuck downhole

Log / Test / Stimulate Existing Vertical producers (Redevelopment Phase 2B)

Four existing vertical producers (2-20, 2-25, 6-21, and 7-15) were successfully side-tracked with single horizontal laterals into the upper layers of the San Andres as planned. This work was completed during April 2001.

Resolve Conformance at Well 7C-11H (Redevelopment Phase 2)

A procedure has been developed, and the work is planned for July 2001.

Resolve Conformance at Poorly Abandoned Wells (Redevelopment Phase2)

On producing wells around the south perimeter, no significant CO₂ production has been observed. No action was taken during the reporting period on this sub task.

Reduce Reservoir Pressure (not included in DOE funding)

Subtask V.1.9 of the Revised Statement of Work included funds for the deepening of water injection wells inside the Unit boundary, to the *lower San Andres*, to handle increased water injection capacity. 2-18 disposal well was perforated and acidized in the *Canyon/Cisco and Lower Clearfork* intervals on September 14, 1998, as described in previous reports.

Increase Productivity

The main concern at South Cowden is the lack of productivity from wells. The lack of withdrawal rates from producing wells has reduced throughput throughout the reservoir, increasing average reservoir pressure and limiting carbon dioxide (CO₂) injection. Drilling of eight horizontal laterals in existing producer wellbores has increased liquid production by a factor of four from those wells, as shown in the table below. Liquid production increased from 497 barrels liquid per day (BLPD) to 1,907 BLPD, and oil production from those eight wells increased from 86 BOPD in January 2000 to 321 BOPD in June 2001.

Total Production from Eight Horizontal Producers (2-20, 2-25, 6-20, 6-21, 6-22, 6-23, 7-13, 7-15)

Date	Oil Rate (Cal. Day) bbl/d	Gas Rate (Cal. Day) Mcf/d	Water Rate (Cal. Day) bbl/d	Liquid Rate (Cal. Day) bbl/d	GOR MCF/BO	Oil Cut Fraction
Jan-00	86	761	411	497	8.8	0.102
Feb-00	77	789	413	490	10.2	0.089
Mar-00	66	551	408	474	8.3	0.107
Apr-00	52	308	415	467	5.9	0.145
May-00	111	110	614	725	1.0	0.503
Jun-00	111	326	987	1,098	2.9	0.254
Jul-00	151	498	1,905	2,056	3.3	0.232
Aug-00	164	652	2,022	2,186	4.0	0.201
Sep-00	191	712	1,907	2,098	3.7	0.212
Oct-00	159	445	1,874	2,033	2.8	0.263
Nov-00	165	446	1,954	2,119	2.7	0.270
Dec-00	160	449	1,853	2,013	2.8	0.263
Jan-01	156	504	1,761	1,917	3.2	0.236
Feb-01	205	1,091	1,603	1,808	5.3	0.158
Mar-01	261	1,445	1,906	2,167	5.5	0.153
Apr-01	238	1,123	1,826	2,064	4.7	0.175
May-01	249	1,213	1,001	1,250	4.9	0.170
Jun-01	321	1,589	1,583	1,904	5.0	0.168

Maintain Injectivity

Surface injection pressures are being maintained below reservoir fracture pressures. Injection profile surveys run early in the project in vertical injection wells indicated significant out of zone injection into the highly transmissible, and water wet, "A" zone or "Grainstone", the lowest zone in the reservoir. Injecting above fracture pressures initiated fracturing downward into the Grainstone, causing waste of CO₂. Surface pressures for water injection wells were therefore limited to 650 pounds per square inch gauged (psig), and CO₂ injection wells to 1150 psig, to ensure injection below fracture pressures, starting in late 1997.

The table below summarizes the individual CO₂ well injection rates. Average total CO₂ injection for the 12 months ending June 30, 2001, was 6,146 Mcfd, compared to 4,185 Mcfd for the prior 12 months.

South Cowden Unit CO₂ Injection Well Volumes

								Cum	
<u>Date</u>	<u>2-26</u>	<u>2-27</u>	<u>6-25</u>	<u>6-26</u>	<u>6-27</u>	<u>6-28</u>	<u>7-11</u>	<u>Total</u>	<u>Injection</u>
	<u>Mcfd</u>	<u>Mcfd</u>	<u>Mcfd</u>	<u>Mcfd</u>	<u>Mcfd</u>	<u>Mcfd</u>	<u>Mcfd</u>	<u>Mcfd</u>	<u>MMCF</u>
Jul-96	265	72	0	0	0	0	0	337	10
Aug-96	1,306	5	1,571	0	0	0	44	2,925	101
Sep-96	1,382	66	3,438	0	0	0	2,854	7,740	333
Oct-96	1,198	149	3,268	0	0	0	3,216	7,830	576
Nov-96	1,459	76	3,724	0	0	0	3,723	8,982	846
Dec-96	1,266	89	3,781	0	0	0	3,787	8,923	1,122
Jan-97	913	4	3,393	0	0	0	3,328	7,638	1,359
Feb-97	998	54	3,614	0	0	0	3,572	8,237	1,590
Mar-97	1,192	120	3,293	0	0	0	3,887	8,493	1,853
Apr-97	1,263	153	3,670	0	0	0	3,119	8,204	2,099
May-97	839	140	3,445	0	0	0	3,442	7,866	2,343
Jun-97	1,027	652	3,570	0	0	859	3,573	9,682	2,633
Jul-97	938	373	3,371	877	0	979	3,456	9,995	2,943
Aug-97	538	371	2,883	971	0	562	2,932	8,257	3,199
Sep-97	727	294	2,718	793	19	0	686	5,237	3,356
Oct-97	935	387	3,495	896	999	0	2,797	9,509	3,651
Nov-97	946	554	3,457	874	986	0	3,452	10,268	3,959
Dec-97	481	184	2,148	441	482	0	1,690	5,424	4,127
Jan-98	290	1	1,312	397	136	0	1,116	3,251	4,228
Feb-98	354	0	1,113	621	85	0	1,140	3,313	4,321
Mar-98	316	0	1,010	631	33	0	1,190	3,180	4,419
Apr-98	523	5	2,347	1,059	20	0	2,319	6,273	4,608

May-98	157	0	2,476	466	1	0	2,431	5,531	4,779
Jun-98	143	0	2,547	490	0	0	2,401	5,581	4,946
Jul-98	476	303	3,542	409	22	0	1,765	6,517	5,148
Aug-98	565	351	3,790	0	45	0	1,920	6,671	5,355
Sep-98	624	458	3,768	0	80	0	1,971	6,901	5,562
Oct-98	656	434	3,692	350	86	0	2,224	7,442	5,793
Nov-98	1,057	0	3,686	581	134	0	2,437	7,895	6,030
Dec-98	229	0	2,543	377	15	0	1,502	4,666	6,174
Jan-99	102	0	2,536	205	1	0	1,451	4,295	6,308
Feb-99	93	0	2,525	209	5	0	1,455	4,288	6,428
Mar-99	329	203	2,518	209	23	0	1,106	4,387	6,564
Apr-99	390	111	2,568	212	23	0	1,082	4,387	6,695
May-99	196	2	2,565	226	22	0	1,045	4,056	6,821

	Cum								
	226	227	625	626	627	628	711	Total	Injection
<u>Date</u>	<u>Mcf/d</u>	<u>Mcf/d</u>	<u>Mcf/d</u>	<u>Mcf/d</u>	<u>Mcf/d</u>	<u>Mcf/d</u>	<u>Mcf/d</u>	<u>Mcf/d</u>	<u>MMCF</u>
Jun-99	13	36	3,271	235	0	0	1,140	4,695	6,962
Jul-99	149	87	3,466	260	16	0	1,021	4,999	7,117
Aug-99	546	160	3,362	556	37	0	464	5,125	7,276
Sep-99	328	30	2,352	529	1	0	1,063	4,302	7,405
Oct-99	310	5	2,697	541	2	0	1,163	4,717	7,551
Nov-99	296	0	2,418	258	0	0	1,003	3,976	7,670
Dec-99	222	0	2,350	0	2	0	1,157	3,731	7,786
Jan-00	231	0	2,223	0	0	0	1,068	3,521	7,895
Feb-00	616	89	1,930	0	67	0	800	3,502	7,997
Mar-00	1,608	288	0	0	168	0	0	2,064	8,061
Apr-00	813	197	0	996	263	0	0	2,269	8,129
May-00	525	167	962	1,321	118	0	912	4,005	8,253
Jun-00	1,374	275	3,237	0	0	0	3,121	8,007	8,493
Jul-00	1,225	257	3,911	0	0	0	3,079	8,473	8,756
Aug-00	957	77	2,704	0	0	0	2,766	6,504	8,957
Sep-00	1,386	0	2,196	0	0	0	2,042	5,624	9,126
Oct-00	111	0	3,435	0	0	0	3,056	6,602	9,331
Nov-00	0	0	2,358	0	0	0	2,302	4,660	9,470
Dec-00	0	0	2,146	0	0	0	1,875	4,021	9,595
Jan-01	0	0	1,718	0	0	0	3,560	5,278	9,759
Feb-01	0	83	1,586	1,748	1,589	391	849	6,245	9,934
Mar-01	0	79	1,801	1,474	1,470	1,609	0	6,432	10,133
Apr-01	1,242	161	1,889	1,565	1,561	1,499	0	7,916	10,371
May-01	956	87	2,061	1,430	1,405	1,496	0	7,435	10,601
Jun-01	1,040	0	2,548	1,583	1,197	1,434	0	7,802	10,835

CO₂ injection was replaced with water for several months prior to drilling laterals in wells 2-26, 2-27, 6-26, 6-27, 6-28. Similarly, water was injected into well 7C-11H prior to the conformance work in July 2001.

Surface injection pressures continue to increase at injectors 2-26, 6-26, 6-27, and 6-28, and total CO₂ injection decreases as maximum permissible injection pressures are approached. Injection rates into well 2-26 as a dual horizontal have not increased above the rates for the vertical well, but it is believed that total injection remaining in the target zones has increased. Injection of CO₂ into 2-27 has not been possible at the allowed surface pressure. Additional production volumes are needed to maintain a lower reservoir pressure surrounding each of the above wells, and to maintain the processing of the reservoir with CO₂ as fast as possible. Injection rates into wells 7C-11H and 6C-25H, the original horizontal injectors, are stable, and do not appear to be hampered as much by rising reservoir pressure as the other CO₂ injectors. Six of the seven successful horizontal producers are direct offsets to these two injectors, which account for much (but not all) of the withdrawals keeping reservoir pressure stable in these patterns.

Unit Production and Injection Summary

SCU Unit Average Daily Production and Injection

<u>Quarter</u>	<u>PRODUCTION</u>			<u>INJECTION</u>			
	<u>BOPD</u>	<u>BWPD</u>	<u>MCFD</u>	<u>SCU Unit</u> <u>Wtr Inj.</u> <u>BWIPD</u>	<u>SCU</u> <u>2D18</u> <u>BWDPD</u>	<u>Total Unit</u> <u>Wtr Inj</u> <u>BWDP</u>	<u>MCSF/D</u> <u>CO2</u>
1st 1996	383	3,944	90	3,944			0
2nd 1996	356	3,528	89	3,528			0
3rd 1996	337	4,303	91	4,622			3,667
4th 1996	376	4,928	102	4,928			8,579
1st 1997	443	6,110	612	6,110			8,123
2nd 1997	425	6,466	929	6,466			8,584
3rd 1997	446	6,498	1,114	6,498			7,830
4th 1997	487	8,624	1,504	8,624			8,400
1st 1998	463	7,065	974	7,066			3,248
2nd 1998	457	6,999	1,026	7,000			5,795
3rd 1998	495	6,826	1,822	6,827			6,696
4th 1998	511	6,691	2,188	5,302	1,389	6,692	6,668
1st 1999	483	6,378	1,992	4,797	1,582	6,379	4,323
2nd 1999	456	5,985	1,413	4,432	1,553	5,985	4,379
3rd 1999	493	6,139	1,770	4,553	1,587	6,140	4,809

4th 1999	464	6,257	1,739	4,522	1,736	6,258	4,141
1st 2000	431	6,441	1,587	4,644	1,798	6,442	3,029
2nd 2000	452	7,330	1,263	5,468	1,863	7,331	4,761
3rd 2000	546	7,586	1,945	5,463	2,062	7,526	6,880
4th 2000	522	6,966	1,996	5,123	1,844	6,966	5,099
1st 2001	573	6,940	2,171	5,078	1,863	6,941	5,977
2nd 2001	698	6,465	2,447	5,072	1,394	6,466	7,715

Monitor Project Performance

Close monitoring of production data has shown the area around horizontal injection well 6C-25H has the best response to CO₂ to date. Well 6C-25H was drilled horizontally into the zone of interest and has no indications of out of zone injection, unlike its twin well 7C-11H where a fracture system is taking the majority of injected gas. The well is also capable of high injection rates, compared to other wells in the field, typically over 3 MMSCF/D at the injection constraint of 1150 psig surface pressure.

Response from nearby wells to the toe of 7C-11H suggest they are also responding to CO₂, so some percentage of the injected CO₂ must be entering the zone of interest, the majority, however, entering the fracture system and out of zone. Oil production declined on several surrounding producers during the months 7C-11H has been on water injection. A conformance improvement job in 7C-11H to seal the major zone of loss at the toe is scheduled for July 2001.

In the Northwest area of the CO₂ flood, two wells have so far been unsuccessful. Horizontal producer 2-20 has produced poorly, both in terms of oil rate and total liquid rate (see table of monthly produced volumes). Injector 2-27 likely has wellbore damage, and is unable to inject CO₂ at the maximum allowed 1,150 psig.

Redevelopment Results

Reducing Out Of Zone Injection

The San Andres intervals were split into 7 layers (A, B, C, D, E, F and G) as part of the reservoir characterization performed in the mid 1990s. Zone A is the deepest zone. The structure is tilted, so in some areas of South Cowden the majority of the San Andres is above the oil water contact at -1800' subsea, and in others below the contact. The CO₂ development team highlighted the need for injecting CO₂ in the upper layers, or the "in zone" section of the San Andres where the D, E, F and G layers are above the original oil water contact. A brief

history of vertical and horizontal well CO₂ conformance observed during CO₂ flood operation is summarized below.

Former Vertical Injection Wells

There were a total of five vertical CO₂ injection wells in the South Cowden Unit. Well 6-24 was considered for a sixth injector, but was never converted. It has been shut in and used as an observation well since gas production and GOR became too high. All five of these vertical wells have been converted to horizontal injectors, as detailed below.

Prior Condition/Current Condition, Former Vertical Injectors

Well 2-26: CO₂ was entering perforations in C to G zones but channeling to below B zone. Vertical wellbore was squeezed, a West lateral and an East lateral were completed in April 2001.

Well 2-27: CO₂ was entering perforations primarily in B and C zone but channelling to below B zone. Vertical wellbore was squeezed, and a single lateral was drilled to the West. A major fracture interval was encountered during drilling, and Halliburton Permseal and zonesal jobs were done to seal the fractures. The lateral was completed in March 2001. CO₂ injection has been near zero Mcfd, and cost-effective stimulation options are being evaluated.

Well 6-24: Currently a shut in producer with high CO₂ rates. Gas breakthrough zones are not known. The well may be converted to CO₂ injection at some future date.

Well 6-26: CO₂ was entering perforations in C zone but channeled to below C zone. Vertical wellbore was squeezed, and a North lateral and a South lateral were completed in December 2000.

Well 6-27: CO₂ was entering perforations in E zone possibly a small channel below. Vertical wellbore was squeezed, and a North lateral and a South lateral were completed in December 2000.

Well 6-28: CO₂ was entering perforations in D zone, possibly a channel below. No injection 9/1997 – 1/2001. Vertical wellbore was squeezed, a North lateral and a South lateral were completed in January 2001.

Horizontal Injection Wells

Well 6C-25H Well was drilled in E zone at target depth of 4689' total vertical depth (TVD). Well length drilled in E zone approximately 1900'. Well injecting as predicted and "in zone". No work was done on this injector during the report period.

Well 7C-11H: Well drilled in E zone at target depth of 4672' TVD. Well length drilled in E zone approximately 1300'. Effective length of well taking CO₂ was 40', near the "toe" of well, in some form of fracture plane. A conformance job was scheduled for July 2001 to seal the fractured interval where most loss is occurring.

Production Monitoring – Horizontal Producer Rate Histories

The latest 18 months of production are shown for each well in the tables below.

Well Number	Date	Oil Rate (Cal. Day) bbl/d	Gas Rate (Cal. Day) Mcf/d	Water Rate (Cal. Day) bbl/d	Liquid Rate (Cal. Day) bbl/d
-----	-----	-----	-----	-----	-----
220	Jan-00	0	0	0	0
220	Feb-00	0	0	0	0
220	Mar-00	0	0	53	53
220	Apr-00	1	0	78	79
220	May-00	2	0	140	142
220	Jun-00	2	0	121	123
220	Jul-00	2	0	293	295
220	Aug-00	1	0	139	140
220	Sep-00	1	0	114	115
220	Oct-00	1	0	167	168
220	Nov-00	1	0	142	143
220	Dec-00	1	0	170	171
220	Jan-01	2	0	141	143
220	Feb-01	1	0	128	129
220	Mar-01	2	0	157	159
220	Apr-01	1	0	103	104
220	May-01	1	0	36	37
220	Jun-01	1	0	35	36

Well Number	Date	Oil Rate (Cal. Day) bbl/d	Gas Rate (Cal. Day) Mcf/d	Water Rate (Cal. Day) bbl/d	Liquid Rate (Cal. Day) bbl/d
-----	-----	-----	-----	-----	-----
225	Jan-00	3	0	185	188
225	Feb-00	4	0	197	201
225	Mar-00	4	0	227	231

225	Apr-00	5	0	220	225
225	May-00	9	0	176	185
225	Jun-00	9	0	145	154
225	Jul-00	11	0	159	170
225	Aug-00	9	0	151	160
225	Sep-00	8	1	152	160
225	Oct-00	7	1	130	137
225	Nov-00	8	1	120	128
225	Dec-00	8	1	124	132
225	Jan-01	7	3	122	129
225	Feb-01	5	2	78	83
225	Mar-01	23	34	297	320
225	Apr-01	50	8	551	601
225	May-01	69	76	371	440
225	Jun-01	67	102	304	371

Well Number	Date	Oil Rate (Cal. Day) bbl/d	Gas Rate (Cal. Day) Mcf/d	Water Rate (Cal. Day) bbl/d	Liquid Rate (Cal. Day) bbl/d
-----	-----	-----	-----	-----	-----
620	Jan-00	41	599	14	55
620	Feb-00	44	541	10	54
620	Mar-00	51	551	12	63
620	Apr-00	38	308	11	49
620	May-00	0	0	0	0
620	May-00	9	50	231	240
620	Jun-00	39	162	210	249
620	Jul-00	58	231	165	223
620	Aug-00	69	216	141	210
620	Sep-00	60	174	132	192
620	Oct-00	67	197	149	216
620	Nov-00	74	200	123	197
620	Dec-00	74	226	123	197
620	Jan-01	92	464	8	100
620	Feb-01	80	466	14	94
620	Mar-01	54	353	126	180
620	Apr-01	64	388	136	200
620	May-01	99	430	120	219
620	Jun-01	75	463	122	197

Well Number	Date	Oil Rate (Cal. Day) bbl/d	Gas Rate (Cal. Day) Mcf/d	Water Rate (Cal. Day) bbl/d	Liquid Rate (Cal. Day) bbl/d
-----	-----	-----	-----	-----	-----
621	Jan-00	5	0	67	72
621	Feb-00	4	0	56	60
621	Mar-00	4	0	64	68
621	Apr-00	4	0	61	65
621	May-00	3	0	52	55
621	Jun-00	3	0	42	45
621	Jul-00	4	0	46	50
621	Aug-00	3	0	49	52
621	Sep-00	2	0	76	78
621	Oct-00	3	0	77	80
621	Nov-00	3	0	64	67
621	Dec-00	3	0	69	72
621	Jan-01	2	0	54	56
621	Feb-01	3	37	28	31
621	Mar-01	19	216	271	290
621	Apr-01	24	327	338	362
621	May-01	15	306	270	285
621	Jun-01	16	376	260	276

Well Number	Date	Oil Rate (Cal. Day) bbl/d	Gas Rate (Cal. Day) Mcf/d	Water Rate (Cal. Day) bbl/d	Liquid Rate (Cal. Day) bbl/d
-----	-----	-----	-----	-----	-----
622	Jan-00	5	1	12	17
622	Feb-00	4	0	4	8
622	Mar-00	6	0	1	7
622	Apr-00	4	0	1	5
622	May-00	2	0	1	3
622	Jun-00	0	0	0	0
622	Jun-00	19	2	846	865
622	Jul-00	23	1	1,151	1,174
622	Aug-00	18	2	1,028	1,046
622	Sep-00	16	2	1,012	1,028
622	Oct-00	19	3	1,110	1,129
622	Nov-00	20	3	1,019	1,039
622	Dec-00	19	3	1,022	1,041
622	Jan-01	18	5	1,009	1,027
622	Feb-01	33	25	819	852

622	Mar-01	17	9	457	474
622	Apr-01	0	0	0	0
622	May-01	34	0	540	574
622	Jun-01	55	16	788	843

Well Number	Date	Oil Rate (Cal. Day) bbl/d	Gas Rate (Cal. Day) Mcf/d	Water Rate (Cal. Day) bbl/d	Liquid Rate (Cal. Day) bbl/d
-----	-----	-----	-----	-----	-----
623	Jan-00	28	161	59	87
623	Feb-00	18	248	88	106
623	Mar-00	0	0	0	0
623	Apr-00	0	0	0	0
623	Apr-00	7	48	130	137
623	May-00	10	0	344	354
623	Jun-00	5	0	243	248
623	Jul-00	13	1	267	280
623	Aug-00	17	16	270	287
623	Sep-00	17	48	199	216
623	Oct-00	18	58	224	242
623	Nov-00	19	57	194	213
623	Dec-00	18	62	195	213
623	Jan-01	17	111	192	209
623	Feb-01	18	236	165	183
623	Mar-01	9	83	98	107
623	Apr-01	0	0	0	0
623	May-01	12	208	150	162
623	Jun-01	20	307	165	185

Well Number	Date	Oil Rate (Cal. Day) bbl/d	Gas Rate (Cal. Day) Mcf/d	Water Rate (Cal. Day) bbl/d	Liquid Rate (Cal. Day) bbl/d
-----	-----	-----	-----	-----	-----
713	Jan-00	5	0	26	31
713	Feb-00	3	0	14	17
713	Mar-00	0	0	0	0
713	Apr-00	0	0	0	0
713	Apr-00	85	62	73	158
713	May-00	76	276	70	146
713	Jun-00	69	334	70	139
713	Jul-00	55	419	67	122
713	Aug-00	73	477	63	136

713	Sep-00	50	220	63	113
713	Oct-00	46	187	68	114
713	Nov-00	32	188	74	106
713	Dec-00	32	210	77	109
713	Jan-01	28	338	71	99
713	Feb-01	33	307	51	84
713	Mar-01	41	227	60	101
713	Apr-01	48	250	65	113
713	May-01	38	264	54	92
713	Jun-01	35	211	49	84

Well Number	Date	Oil Rate (Cal. Day) bbl/d	Gas Rate (Cal. Day) Mcf/d	Water Rate (Cal. Day) bbl/d	Liquid Rate (Cal. Day) bbl/d
-----	-----	-----	-----	-----	-----
715	Jan-00	1	0	48	49
715	Feb-00	1	0	44	45
715	Mar-00	1	0	51	52
715	Apr-00	1	0	44	45
715	May-00	2	0	42	44
715	Jun-00	2	0	34	36
715	Jul-00	3	0	38	41
715	Aug-00	2	0	33	35
715	Sep-00	3	0	63	66
715	Oct-00	5	0	94	99
715	Nov-00	4	0	77	81
715	Dec-00	4	0	80	84
715	Jan-01	1	0	27	28
715	Feb-01	42	134	89	131
715	Mar-01	54	161	132	186
715	Apr-01	42	116	93	135
715	May-01	52	193	123	175
715	Jun-01	56	209	120	176

2-18 Disposal Well/Water Injection Cut Back/CO₂ Injection Increase

The well has regulatory approval to inject up to 3000 psi surface injection pressure. A step rate test and injection log was planned to determine the wells' injectivity into the current Canyon and Clearfork reservoir intervals. The well was tested in late April 2000. It was determined

that up to 7500 barrels of water per day (bw/d) could be injected at the 3000 psi injection pressure.

Costs estimates were prepared for renting/purchasing a pump upgrade to inject at higher surface pressures. However, after starting up an unused 600 horse power (hp)/1200 psig pump at the lease, rates of 2500 bw/d at 1000 psi were being injected in the well.

After reviewing historical water injection at the lease the SCU team decided to cut back water injection in the south of the field. This would allow reservoir pressure around Tract 6 to lower and improve CO₂ movement down toward 6-22 well and allow greater volumes of CO₂ to be injected at 6C-25H.

CONCLUSION

Oil production response around CO₂ injector 6C-25H has been good, both in vertical producers and in horizontal producers. Oil response continues to improve around injector 7C-11H, and around CO₂ injector 2-26W. Total injection rate into 2-26W as a horizontal well has not increased compared to the rate as a vertical injector. However, it is probable that as a horizontal injector a higher injection rate of CO₂ is staying in the intended pay zones in 2-26W.

Very little response has occurred near CO₂ injector 2-27W because CO₂ injection has been very poor. The response, which has occurred, is attributed to nearby CO₂ injector 2-26W, and probable water flow through fractures from the area around Emmons well 207W.

Increasing reservoir pressure along the South Cowden Unit boundary with the Emmons Unit has caused a decrease in injectivity in SCU CO₂ injection wells 6-26W, 6-27W, and 6-28W. This condition will only be improved by lowering reservoir pressure within the south area of the Emmons Unit. No means of salt-water disposal (SWD) exists on the Emmons Unit, and options for SWD are being evaluated.

Use of existing wellbores and horizontal laterals to increase production rates has proved effective in seven of the eight horizontal producers. Oil production on the South Cowden Unit has increased from an average rate of 452 BOPD in the second quarter of 2000 to 698 BOPD in the second quarter of 2001. The total pore volume of CO₂ injected to date in wells 6-26W, 6-27W, and 6-28W has not been sufficient to determine the economic viability of these injector patterns.

REFERENCES

None.

BIBLIOGRAPHY

None.

LIST OF ACRONYMS AND ABBREVIATIONS

Authority for Expenditure	AFE
Barrels of liquid per day	BLPD
Barrels of Oil per day	BOPD
Barrels of Water per day	bw/d
Carbon Dioxide	CO ₂
Department of Energy	DOE
Horse power	hp
Measurement while Drilling	MWD
Million standard cubic feet per day	MMSCF/D
Original oil in place	OOIP
Pounds per square inch gauged	psig
Reservoir characterization	RC
Revised Statement of Work	RSOW
Salt Water Disposal	SWD
Shallow shelf carbonate	SSC
South Cowden Unit	SCU
Statement of Work	SOW
Stock tank barrels	STB
Stock tank barrels of oil	STBO
Thousand cubic feet per day	Mcfd
Total vertical depth	TVD
Water alternating gas	WAG

LIST OF GRAPHS

<u>Graph</u>	<u>Description</u>
1	Historical Injection Rates and Surface Pressures of Well 2-18

GRAPH

SCU 2-18 Disposal Well

Graph 1
Historical Injection Rates and Surface Pressure, SWD Well 2-18, 1999-2001