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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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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Contractor Name and Address:	**Phillips Petroleum Company** **4001 Penbrook Street** **Odessa, Texas 79762**
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OBJECTIVE

The first project objective is to utilize reservoir characterization and advanced technologies to optimize the design of a carbon dioxide (CO_2) project for the South Cowden Unit (SCU) located in Ector County, Texas. The SCU is a mature, relatively small, shallow shelf carbonate unit nearing waterflood depletion. The second project objective is to demonstrate the performance and economic viability of the project in the field. All work during the second quarter falls within the demonstration project.

SUMMARY OF TECHNICAL PROGRESS

BUDGET PHASE II

TASK V FIELD DEMONSTRATION

Reduce Reservoir Pressure (not included in DOE funding)

Well 2-18 disposal well was perforated and acidized in the Canyon/Cisco and Lower Clearfork intervals on September 14, as described in previous reports.

Initial injection rates were 2600 barrels of water per day (bw/d) at 640 pounds per square inch gauged (psig) surface injection pressure. Average injection rate and pressure, for the reporting period, were 1549 bw/d and 754 psig. Figure 1 shows historical injection rates and surface pressures for this well.

Increase Throughput

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 (CO_2) injection.

Lack of productivity is caused, in the majority of wells, by an increase in effective skin factor due to build up of scale and heavy end hydrocarbons in the wellbore. A sampling, analysis and chemical treatment was undertaken in producing wells to improve productivity throughout 1998, as documented in previous quarterly reports. Recently, low crude oil prices have dictated a cut back on operating expenses over the lease, so treatments were reduced during the first half of 1999.

We are currently looking at alternatives for re-stimulation that can improve injectivity/productivity without the use of stimulation above fracture pressures. These include the use of Halliburton's Stimtube/Stimgun/Powerperf technology followed by matrix acid stimulation, lanced perforating and use of short radius drilling. The candidate well No. 6-24 was initially identified to attempt to quantify re-stimulation techniques and their effect on injectivity/productivity. Due to the high pressures at the well, however, it would prove to be too expensive to work on this well to attempt to use these technologies. Wells 6-23 or 6-29 are currently being looked as alternative candidates. Well No. 6-24

will be cleaned out and converted to injection.

Core samples from 6-24, from various zones in the San Andres, were tested for acid solubility and reaction time at various temperatures. This revealed carbonate intervals with high anhydrite content or intervals with high clastic content tended to have slow reaction times when compared to low anhydrite carbonates. For example, upper layers in the E zone (high anhydrite content) and the interval between the C and D zones (high clastic content) had lower reaction time when compared to the low anhydrite content C zone. Sensitivities to acid treatment temperature revealed the reaction times for high anhydrite content intervals could be improved by raising treatment temperature, whereas low anhydrite or high clastic content intervals reaction time was not effected by treatment temperature. The results of these lab tests are important for two reasons.

1) Any acid stimulation performed above fracture pressure, which would allow communication to low anhydrite content intervals, will preferentially react with those low anhydrite intervals. Therefore, any acid stimulation performed on an interval perforated in the target E zone, which had to be performed above fracture pressure, would allow open communication to lower intervals. Most noticeably this would be in the high permeability (low anhydrite) grainstone interval, which is normally below the oil water contact.

2) To improve acid reaction times and solubility of the rock where there is a higher anhydrite content it can be heated at surface.

In addition to the stimulation techniques described above, costs estimates are being prepared to drill short radius wells from existing wellbores. A service company from Houston has been contacted to perform this service.

Injectivity and Out Of Zone Injection

As discussed in the previous quarterly reports, surface injection pressures were maintained below reservoir fracture pressures.

Injection profile surveys 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 CO_2 wastage.

Surface pressures for water injection wells were therefore limited to 650 psig, and CO_2 injection wells to 1150 psig, to ensure injection below fracture pressures, starting in late 1997.

Injected volumes and surface pressures were closely monitored to observe injectivity. The table below summarizes some of the individual CO_2 well injection rates.

Individual CO2 Injection Rates

	SCU 6C27	SCU 6C26	SCU 2C26	SCU 2C27	SCU 6C-25H	SCU 7C-11H
	Rate Mcf/D	Rate Mcf/D	Rate Mcf/D	Rate Mcf/D	Rate Mcf/D	Rate Mcf/D
Sep-97	19	793	727	294	2,718	686
Oct-97	999	896	935	387	3,495	2,797
Nov-97	986	874	946	554	3,457	3,452
Dec-97	482	441	481	184	2,148	1,690
Jan-98	136	397	290	1	1,312	1,116
Feb-98	85	621	354	0	1,113	1,140
Mar-98	33	631	316	0	1,010	1,190
Apr-98	20	1,059	523	5	2,347	2,319
May-98	1	466	157	1	2,476	2,431
Jun-98	0	490	143	0	2,547	2,401
Jul-98	22	409	476	303	3,542	1,766
Aug-98	45	0	565	351	3,790	1,920
Sep-98	80	0	625	458	3,768	1,971
Oct-98	86	350	656	434	3,692	2,224
Nov-98	134	581	1,057	0	3,686	2,437
Dec-98	15	377	229	0	2,543	1,502
Jan-99	1	206	102	0	2,536	1,451
Feb-99	5	209	94	0	2,525	1,455
Mar-99	23	209	329	203	2,518	1,106
Apr-99	23	212	390	111	2,568	1,082
May-99	22	226	196	2	2,565	1,045
Jun-99	0	235	13	36	3,271	1,140

Actual injection rates have therefore reduced since limiting surface pressures, most noticeably in vertical wells.

There are two reasons for poor injection rates:

1) High reservoir pressure in the zone of interest causing lack of pressure differential between well bore and reservoir, reducing the wells capacity to inject CO_2.

2) Lack of injectivity, due either to skin damage or poorer reservoir quality than anticipated.

As discussed above, high reservoir pressure is caused by lack of throughput within the project area and lack of off lease produced water disposal. Methods for improving throughput and productivity

were discussed above.

Lack of injectivity is of more concern for vertical injection wells. Continued monitoring of injection volumes and pressures for these wells will determine if further intervention work or methods to improve injectivity will be required. It is anticipated, however, injection volumes will increase once throughput and reservoir pressures improve.

During December 1998 low crude prices dictated a cut back of CO_2 purchases to the lease. Overall CO_2 injection was therefore reduced from 7.9 MMSCF/D to 4.7 MMSCF/D in December 1998. Average CO_2 purchases were maintained at 4.4 MMSCF/D for this report period.

As discussed in previous reports, horizontal CO_2 injection well 7C-11H intercepted a fracture system. Significant losses are occurring in this well into this fracture system. Indications from previous gas tracer studies indicated possible direct communication path to vertical leaseline well 6-28, which had significant CO_2 production while on test. To try and resolve this concern a dye injection test is planned for 7C-11H. This will involve conversion to water injection while a batch of fluorescent dye is added. Monitoring of wells surrounding 7C-11H will determine if such direct communication paths exist. This activity is planned for 3rd quarter 1999.

Purchase CO_2 and Operation of Recycle Compression Facilities

The CO_2 recycle compression facilities have been in continuous operation during the second quarter, 1999.

Gas injection volumes for the four SCU injection wells and the three co-operative lease line injection wells are reported below. These volumes have been updated and corrected from previous reports.

South Cowden Unit Gas (CO2) Injection

	Jul-97	Aug-97	Sep-97	Oct-97	Nov-97
Monthly Mcf	309,844	255,958	157,118	294,766	308,048
Daily Avg mcf/d	9,995	8,257	5,237	9,509	10,268
Cumulative Mcf	2,943,129	3,199,087	3,356,205	3,650,971	3,959,019

	Dec-97	Jan-98	Feb-98	Mar-98	Apr-98
Monthly Mcf	168,149	100,782	92,772	98,593	188,185
Daily Avg mcf/d	5,424	3,251	3,313	3,180	6,273
Cumulative Mcf	4,127,168	4,227,950	4,320,722	4,419,315	4,607,500

	May-98	Jun-98	Jul-98	Aug-98	Sep-98
Monthly Mcf	171,447	167,425	202,031	206,799	207,030
Daily Avg mcf/d	5,531	5,581	6,517	6,671	6,901
Cumulative Mcf	4,778,947	4,946,372	5,148,403	5,355,202	5,562,232

	Oct-98	Nov-98	Dec-98	Jan-99	Feb-99
Monthly Mcf	230,705	236,839	144,641	133,140	120,056
Daily Avg mcf/d	7,442	7,895	4,666	4,295	4,288
Cumulative Mcf	5,792,937	6,029,776	6,174,417	6,307,557	6,427,613

	Mar-99	Apr-99	May-99	Jun-99
Monthly Mcf	136,002	131,614	125,738	140,844
Daily Avg mcf/d	4,387	4,387	4,056	4,695
Cumulative Mcf	6,563,615	6,695,229	6,820,967	6,961,811

Unit Production

A summary of quarterly average daily production and injection follows:

SCU Unit Average Daily Production and Injection

	PRODUCTION			INJECTION			
Quarter	BOPD	BWPD	MCFD	SCU Unit Wtr Inj. BWIPD	SCU 2D18 BWDPD	Total Unit Wtr Inj BWDP	MCSF/D CO2
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	5,984	1,413	4,432	1,553	5,985	4,379

Monitor Project Performance

Close monitoring of production data has shown the area around horizontal injection well 6C-25H has the best response to CO_2 todate. Suggesting areas where a) zonal isolation of injected CO_2 into the zone of interest, and b) high injectivity are possible will have the greatest benefit from CO_2 injection.

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.

Other areas of the field, such as around vertical injection well 2-27, suggest CO_2 has less response to nearby wells. Well 2-22 appears to have earliest CO_2 breakthrough, suggesting the highest transmissibility between the pair. Other wells surrounding 2-27 have shown little indication of CO_2 response.

Response from nearby wells to the toe of 7C-11H suggest they are also responding to CO_2, so some percentage of the injected CO_2 must be entering the zone of interest, the majority, however, entering the fracture system and out of zone.

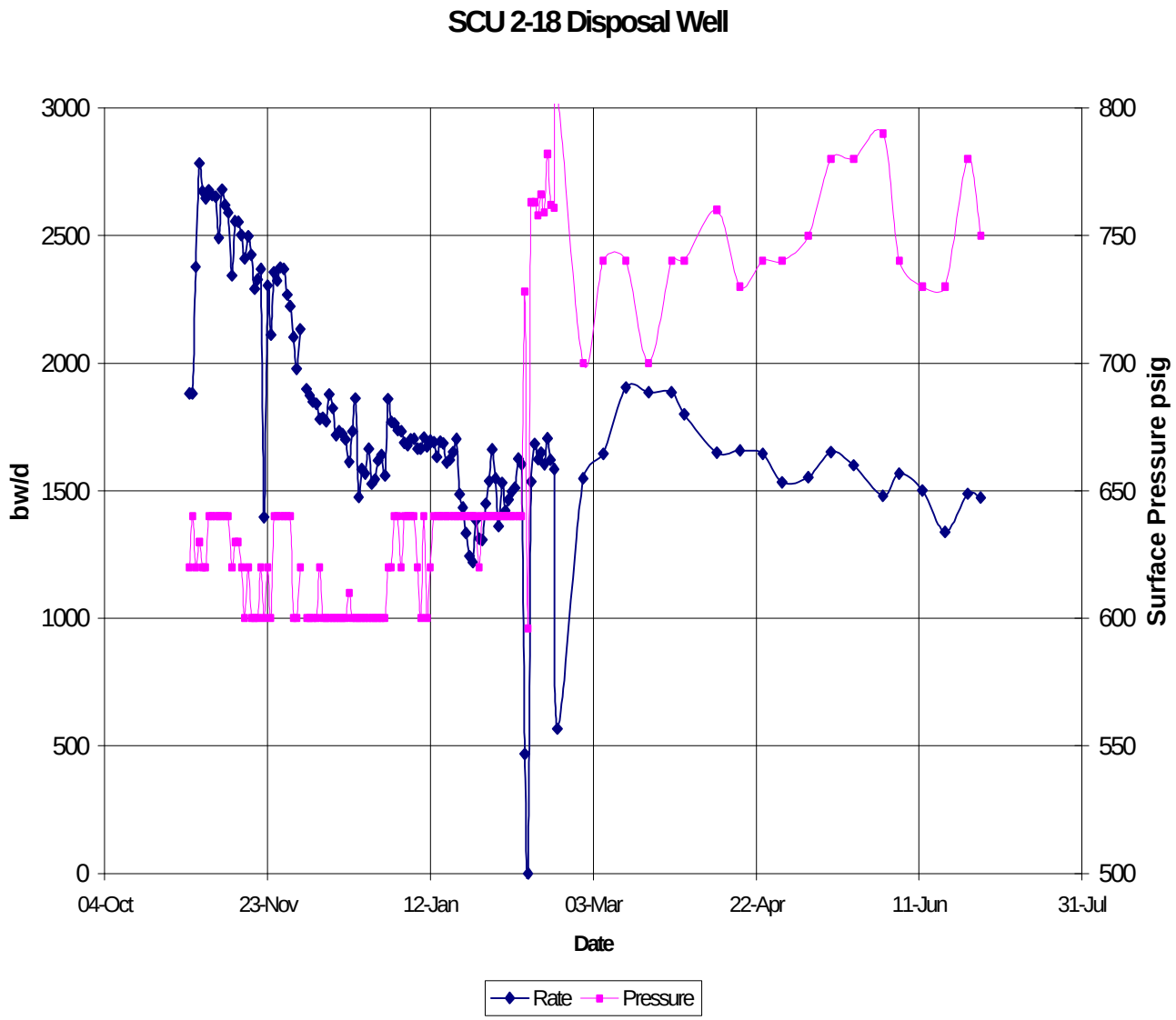

Figure 1
Historical Injection Rates and Surface Pressure