Report Title:

Application of Reservoir Characterization and Advanced Technology to Improve Recovery and Economics in a Lower Quality Shallow Shelf San Andres Reservoir

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OBJECTIVES

The Class 2 Project at West Welch was designed to demonstrate the use of advanced technologies to enhance the economics of improved oil recovery (IOR) projects in lower quality Shallow Shelf Carbonate (SSC) reservoirs, resulting in recovery of additional oil that would otherwise be left in the reservoir at project abandonment. Accurate reservoir description is critical to the effective evaluation and efficient design of IOR projects in the heterogeneous SSC reservoirs. Therefore, the majority of Budget Period 1 was devoted to reservoir characterization. Technologies being demonstrated include:

1. Advanced petrophysics
2. Three-dimensional (3-D) seismic
3. Crosswell bore tomography
4. Advanced reservoir simulation
5. Carbon dioxide (CO_2) stimulation treatments
6. Hydraulic fracturing design and monitoring
7. Mobility control agents

SUMMARY OF TECHNICAL PROGRESS

West Welch Unit is one of four large waterflood units in the Welch Field in the northwestern portion of Dawson County, Texas. The Welch Field was discovered in the early 1940's and produces oil under a solution gas drive mechanism from the San Andres formation at approximately 4800 ft. The field has been under waterflood for 30 years and a significant portion has been infill-drilled on 20-ac density. A 1982-86 pilot CO_2 injection project in the offsetting South Welch Unit yielded positive results. Recent installation of a CO_2 pipeline near the field allowed the phased development of a miscible CO_2 injection project at the South Welch Unit.

The reservoir quality at the West Welch Unit is poorer than other San Andres reservoirs due to its relative position to sea level during deposition. Because of the proximity of a CO_2 source and the CO_2 operating experience that would be available from the South Welch Unit, West Welch Unit is an ideal location for demonstrating methods for enhancing economics of IOR projects in lower quality SSC reservoirs. This Class 2 project concentrates on the efficient design of a miscible CO_2 project based on detailed reservoir characterization from advanced petrophysics, 3-D seismic interpretations and crosswell tomography interpretations.

During the quarter the 3-D depiction of the CO_2-invaded area was quantified in terms of relative saturation. Also, the second interwell seismic monitor survey was successfully acquired on the southern pattern. A second completion attempt was conducted on the horizontal lateral drilled in 11/00.

INTERWELL SEISMIC

Beginning on January 29, 2001, the second round of interwell seismic monitor surveys was acquired on the same six survey lines (south pattern) used for the first monitor survey conducted in December 1999 (Figure 1). Field work was completed in February and data processing and interpretation continued through the end of the first quarter. Preliminary results indicate presence of CO2 on all six survey lines as of the date of the second monitor surveys.

During the first quarter of 2001, Advanced Reservoir Technologies was successful in developing a technique for estimating saturation of the injected CO2 based on corresponding changes in compressional and shear wave velocities computed from interwell seismic data. The technique involves using a combination of the Biot-Gassman equations together with Woods equation, which allows an estimate of compressibility for a mixture of two fluids based on compressibility and relative saturations of each. Currently there is not a method available for calibrating CO2 saturations in the Welch study area so the results can only be scaled as estimated relative saturation based on the highest indicated saturation being designated as 100 %. If a method can be developed for calibrating the results then absolute values of saturation can be estimated. Such saturations estimates could then be compared to time equivalent CO2 saturations generated by the simulator to allow further calibration of the reservoir model. The relative saturation estimates, however provide useful information in understanding current performance in the CO2 focus area. The usefulness of this information should increase greatly when the processing and interpretation of the second interwell monitor survey results are completed.

3-D SEISMIC INTEGRATION

No activities involving 3-D seismic were undertaken during the quarter.

NUMERICAL SIMULATION

The modeling requirements have been developed and it is anticipated that the actual simulation will be conducted during the third quarter of 2001. Several future scenarios will be modeled, including various slug sizes, different WAG schedules and stopping CO2 injection in September 2001 when the project terminates.

HORIZONTAL DRILLING

In the last quarter of 2000, producer No. 4853, located at the south end of the DOE, project area was re-entered and a horizontal lateral drilled due north 3500 ft (Figure 2). The strategy behind drilling the lateral and details on the drilling operations were reported in the 4thQ 2000 report along with preliminary information on the initial completion attempt using Halliburton’s newly developed Surgi-frac technique. Table 1 is the daily activity log covering the drilling and completion operations. The proposed and actual (surveyed) wellbore path is shown by Figure 3. The wellbore path penetrated the main pay interval- M-3- for most of its lenght (Figure 4). Since the lateral was going updip to the north it was necessary to incline the second half of the lateral to stay in the main pay zone and out of the water bearing lower zone.

Six intervals along the lateral (8385', 7850', 7250', 6520', 5900' and 5300') were chosen for Surgi-frac completion and spaced so no completion would be in line with either of the two rows of injectors that had been intersected. The Surgi-frac technique pumps sand slurry down the tubing and out jets orientated to the plane of minimum stress, allowing the hydraulic horsepower to be focused at one point. The formation is notched by erosion and at the point of impact the kinetic energy of the jetted stream is converted to pressure. When this “stagnation” pressure is slightly greater than the ambient pressure a fracture is initiated.. The fracture is propagated and propped by continuing to pump the sand slurry down the tubing. The jetting action creates an area of low pressure at the mouth of the fracture due to the Bernoulli effect. Fluid is pumped down the back side to maintain pressure in the wellbore. In theory all of the fluid and sand is drawn into fracture by the low pressure zone and there is no leak off into other fractures.

This technique allows multiple fractures to be created at selected points without the use of pack-off elements, which greatly lowers the mechanical risk in a horizontal lateral. Otherwise, fracturing in an open hole lateral is a random affair where a single fracture is created usually in the heel. Horizontal drilling has had limited success in the vertically stratified Permian Age carbonate reservoirs (San Andres and Clear Fork) of the Permian Basin for two primary reasons. Nearly all San Andres and Clear Fork vertical completions require an acid or sand frac treatment to get beyond the wellbore damage and enhance the normal low permeability. Secondly, the stratified pay intervals limit the vertical drainage of the horizontal wellbore to a few feet. A technique such as the Surgi-frac, if successful, overcomes both of these problems.

A summary of the initial Surgi-frac completion attempt on November 29, 2000 is given on Table 2. The first of six planned treatment intervals was near the toe of the lateral at 8385 ft (MD). After notching and initiating the fracture, 19,285 lbs of proppant and 19,714 gals of gelled water were pumped away at 18 BPM. The formation broke down at a bottom hole pressure (BHP) of 4250 psi and treated around 4000 psi (Figure 5). The maximum tubing pressure was 8500 psi, but tubing pressure is not a good indicator of bottom hole performance due to the large pressure loss due to friction and the pressure drop across the jets. The treatment at this interval appears to have successfully initiated and propagated a fracture as indicated by the BHP, which built nearly straight up at the start and then broke over sharply as the formation broke down.

Unfortunately toward the end of the treatment one of the jets washed out as indicated by the drop-off in tubing pressure. The surgi-frac tool was repositioned and the second and third intervals were treated. The tubing pressure was much lower at the same pump rate (18 BPM) due to the elimination of pressure drop across the jets and the BHP did not show the sharp breakover caused by the formation parting. Only shallow erosion of the wellbore probably occurred at the second and third intervals and the sand slurry flowed toward the initial fracture in the toe of the lateral at 8385 ft (MD). Sand fill occurred from 8051 ft to 8410 ft (MDTD) The proppant had been tagged with radioactive material, but a tracer log run 12/07/00 failed to give any definitive interpretation (Figure 6). The well was placed on rod pump 12/25/00 and achieved a maximum oil rate of 41 BOPD and 610 BWPD with 1206 MCF of gas (CO2). The well test history is shown on Table 3. The CO2 breakthrough had occurred immediately upon producing the well. In the second half of January it was necessary to cut back on CO2 injection to reduce the gas volume being produced in 4853. A severe scale problem was discovered in late January when pulling the production tubing.

The second Surgi-frac completion attempt was conducted 1/25/01 starting with the second interval from the toe at 7246 ft (MD). As shown on Table 4, the five remaining intervals were treated with an average of 15,900 gals of gelled water and 22,200 lbs of proppant at rates varying from 14.8 to 17.5 BPM. The BHP performance (Figure 7) shows that the first two intervals broke back sharply, indicating that a fracture had been initiated and propagated. For the remaining three intervals, the BHP broke over sharply to a fairly constant treating pressure, but did not break back to a lower pressure as often occurs when the formation is parted. While the tracer log (Figure 8) again failed to give any definitive answer as to the placement of proppant, a majority of the tracer activity was at the end of the lateral, implying that most of the stimulation went toward the toe. However pressure performance suggest that the second and third intervals were treated and it is possible that the other three were also.

Sand and scale were reversed out from 7759 ft to TD at 8410 ft (MD). After treating the well for scale, a Reda was run in the vertical hole and the well placed on production 2/8/01. The first reported test (Table 4) was 0 BOPD and 1271 BWPD with 131 MCF of gas on 2/15/01. The well has produced very little oil through March 2001. Due to the scale problem and the breakthrough of CO2, it is impossible to judge the effectiveness of the second Surgi-frac completion attempt based on well tests.

FIELD DEMONSTRATION PHASE

Through March 2001 a total of 4.4 BCF of CO2 had been injected into the project area since initiation of injection in October 1997. Overall oil and gas production was lower than the previous quarter due to restrictions in C02 injection for four of the last six months that started in November 2000 with the four injectors that offset the horizontal lateral. In this quarter injection was restricted during the acquisition of the second interwell seismic monitoring survey during January and part of February 2001. Also the injection into the four injectors offsetting the 4853 lateral continued at a reduced rate. Consequently total CO2 volume injected this quarter was about the same as last quarter.

Monthly performance for the focus area during the first quarter of 2001 is shown on Table 5. Injector 4805 was returned to CO2 injection in March 2001 after having been wagged to water in January 2000. Because of CO2 breakthrough into the 4853 lateral, the four offset injectors were kept at a restricted input rate during the quarter. Injectors 4805 and 4808 injected at their maximum pressures. The gas breakthrough into the 4853 lateral most likely is coming from a gas saturated area near the toe of the lateral as opposed to a direct channel with an injector. As discussed in the Horizontal Lateral Section, there is some evidence that most of the Surgi-frac treatments went into the initial fracture interval near the toe of the lateral, possibly creating an extended frac wing just north of the 4809 and 4811injectors. The volume of gas being produced by 4853 (about 800 mcfpd) is about equal to the individual average injection rate for any of the four injectors offsetting the lateral. A direct channel between an injector and the lateral would be evidenced by a significant change in the injection pressure as the lateral was shut in or opened up. This was the case with injector 4810 which was in direct communication with producer 4843 at one time, but has not occurred in regards to the 4853 horizontal lateral.

It was necessary to shut in 4853 because the volume of produced gas was exceeding the capacity of the gas plant. However 4853 was scheduled to be turned back on in early April 2001. The offsetting injectors will be maintained at their current choke settings and the pressures and rates closely monitored for change when 4853 is turned back on. The 4853 lateral has also communicated with one of the two producers near to the lateral well path and No. 4829 was shut in during the quarter due to high gas (CO2) production.

The strong oil responses in 4844 and 4847 are still occurring. Both responding wells are directly offset by north and south injectors, although one of 4844 offsetting injectors was wagged to water in January 2000. There appears to be oil response in 4850 and possible oil response in 4841. These two wells are direct offsets to active CO2 injectors. Definite gas (CO2) breakthrough has occurred prior to this quarter in Well Nos. 4841, 4843, 4844, 4850 and 4854. These producers are all direct north or south offsets to active CO2 injectors. There also is evidence of limited gas breakthrough in Well Nos 4827, 4828, 4829 and 4842. However, the limitations on well test accuracy and the impact of changes in the injection scheme are such that a well's performance needs to be observed over several quarters before making a final judgement. Well 4843 is a good example of this. For the last couple of quarters it was reported as having an oil response to CO2 injection, but that no longer appears to be the case. Figure 9 shows well response in terms of oil response and gas breakthrough.

As discussed in the last quarterly report, determining when response occurs is not an exact science in a reservoir with the injection and withdrawal history of West Welch. The classic response of a producer to CO2 injection is an initial lowering of water production followed by an increase in gas (mainly CO2) as the miscible front encroaches into the well's drainage area. Oil rate increases as the front approaches the wellbore. Several variations to this pattern have occurred as wells are influenced not only by changes in CO2 injection rates, i.e. pinching back or wagging, but also the changes in what was the established waterflood injection pattern and resulting reservoir pressure distribution. Although our judgement has changed on some wells based on long term performance, there is no new oil response or gas breakthrough that occurred in this quarter.

The low hydrocarbon pore volume processing rate of the CO2 remains the main concern in light of the September 2001 termination date of the project. Only a few of the pattens are approaching a processed reservoir volume where similar projects started to experience response. The restrictions on CO2 injection since November 2000 have only worsened the problem. The return of the 4805 injector to CO2 input will help as well as the injectors offsetting the 4853 lateral being restored to their maximum input rate.

AREA PREPARATION AND CONSTRUCTION

No activity in this quarter.

TECHNOLOGY TRANSFER

No technology transfer activities occurred this quarter.

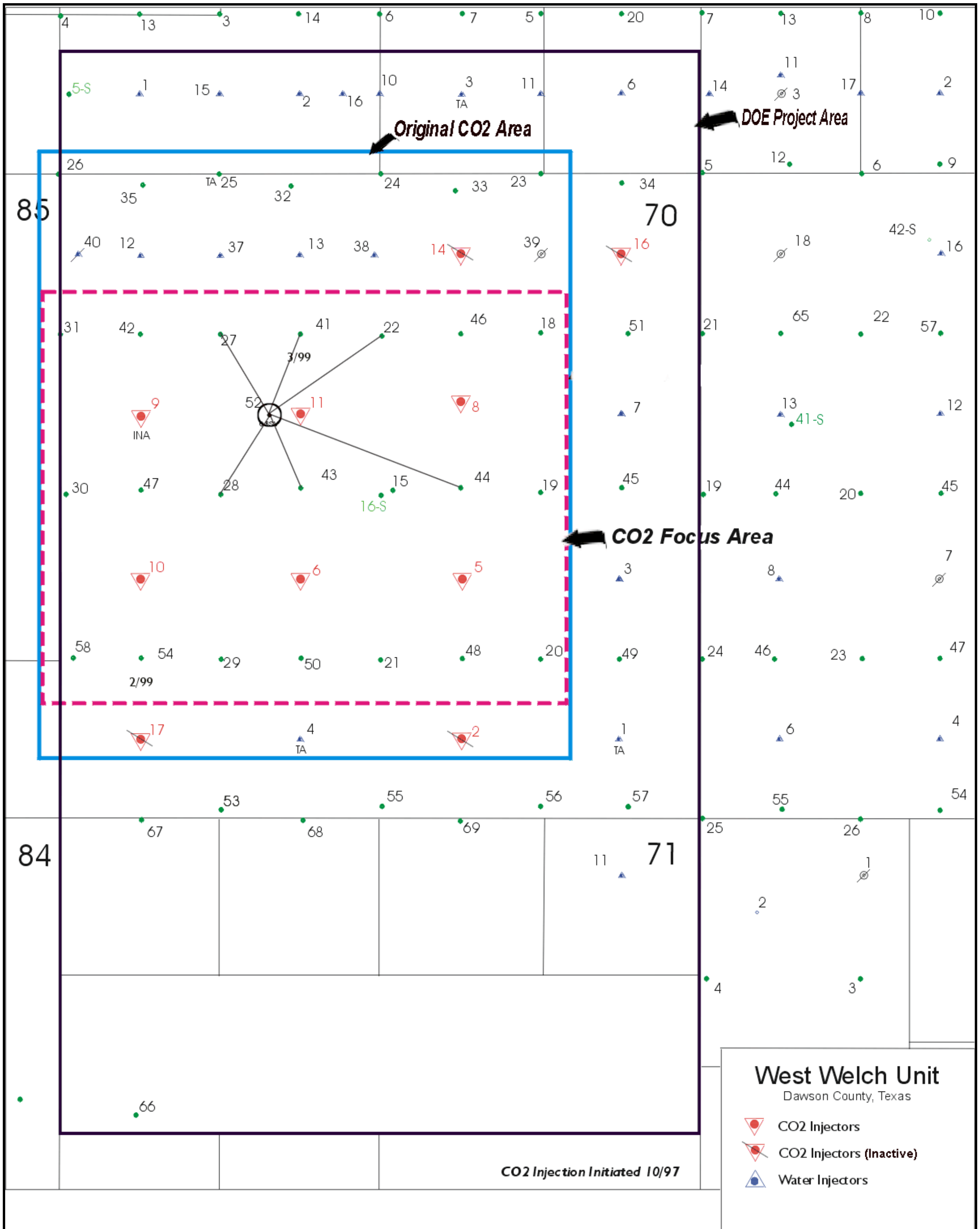

Figure 1
Interwell Seismic Lines for CO2 Monitoring

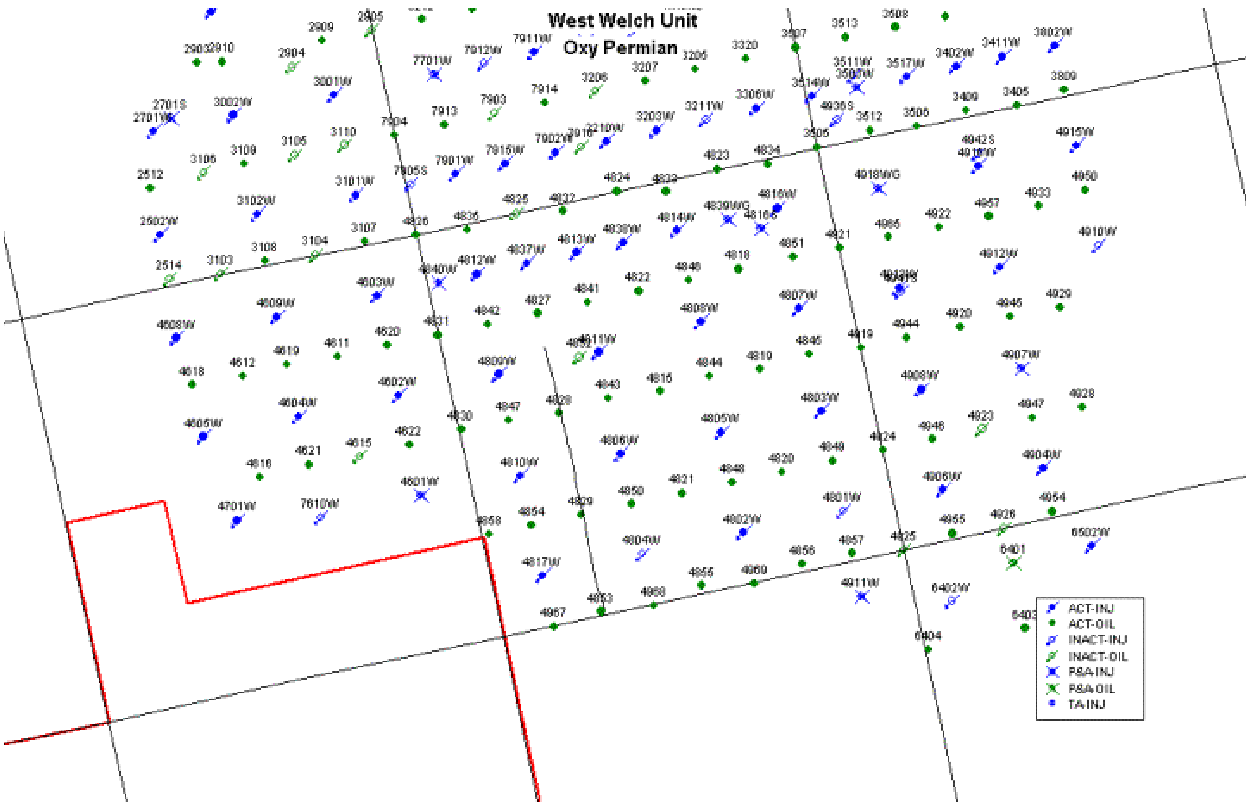

Fig 2 - Wellbore Path WWU 4853 Horizontal Lateral

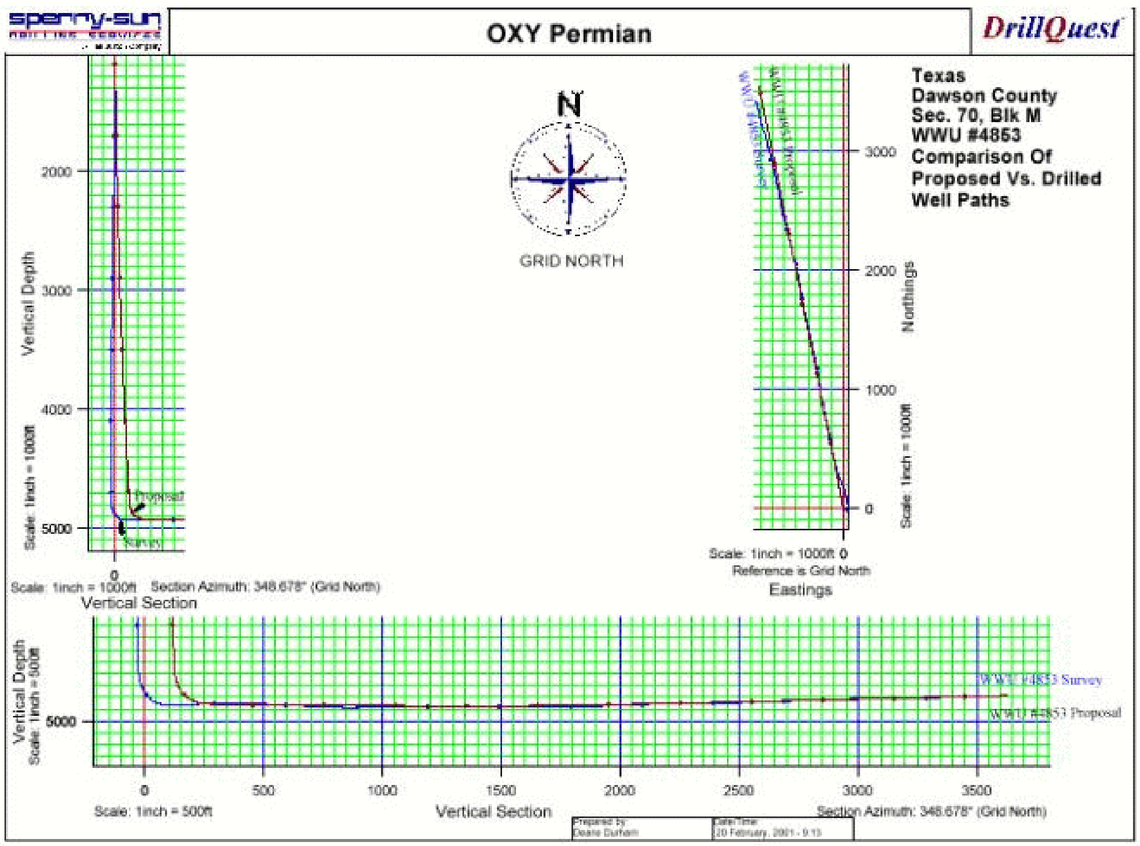

Fig. 3 - Planned vs Final Well Path - WWU 4853 Horizontal Lateral

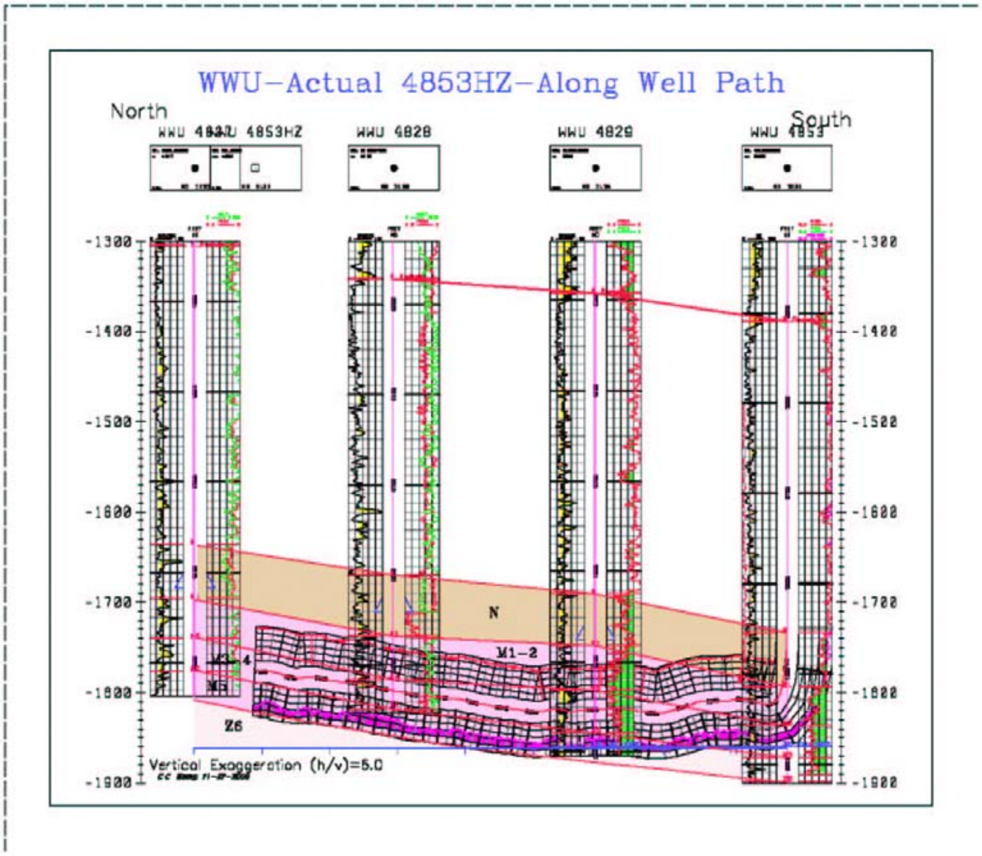

Fig. 4 - Wellbore path through Reservoir - WWU 4853 Horizontal Lateral

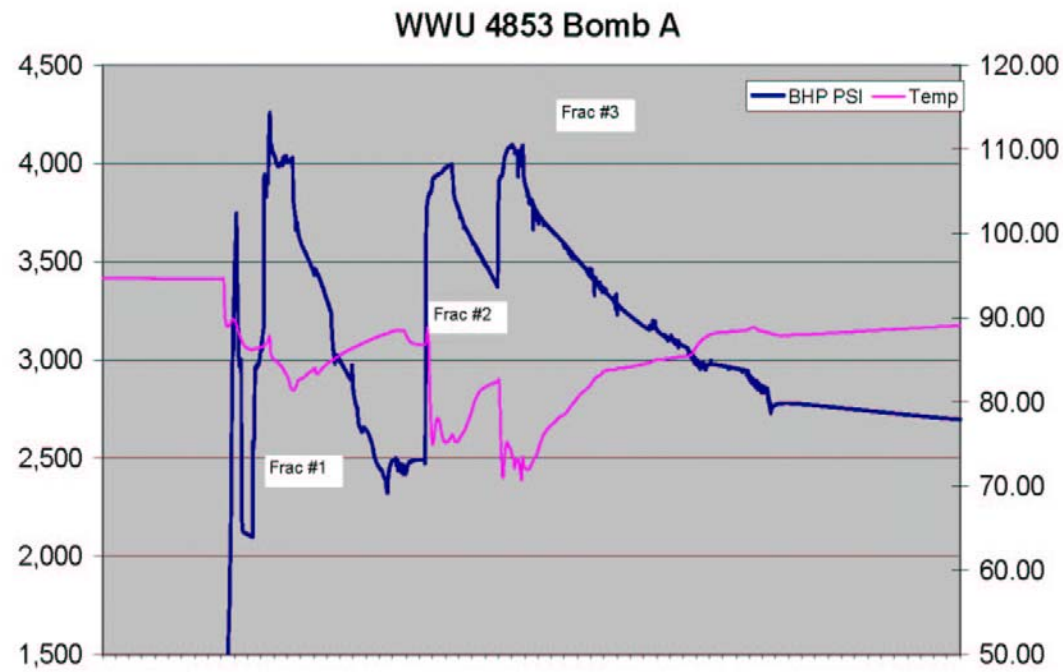

Fig. 5 - BHP & Temp Chart - WWU 4853 Lateral - Initial Surgi-frac Completion Attempt 11/29/00

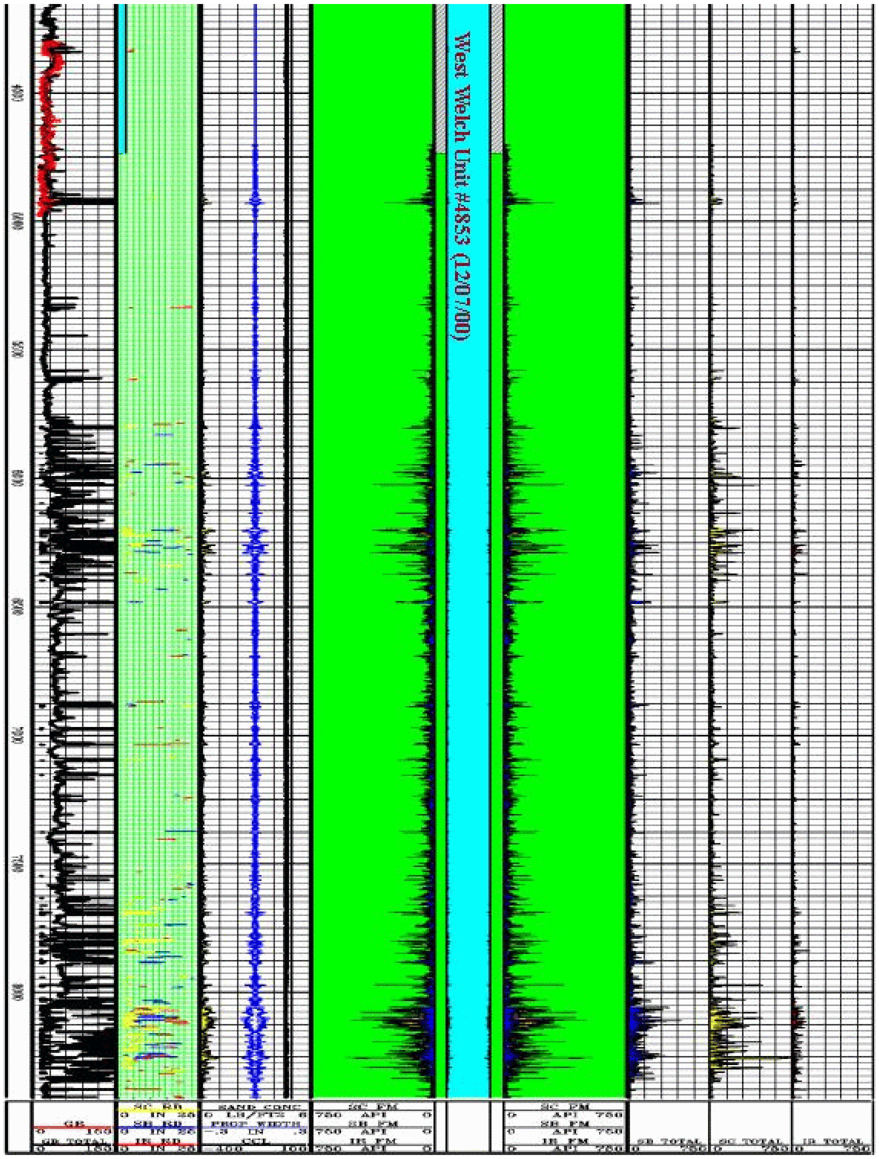

Fig. 6 - Radioactive Tracer Log - WWU 4853 Lateral - Run 12/07/00
After Initial Completion Attempt

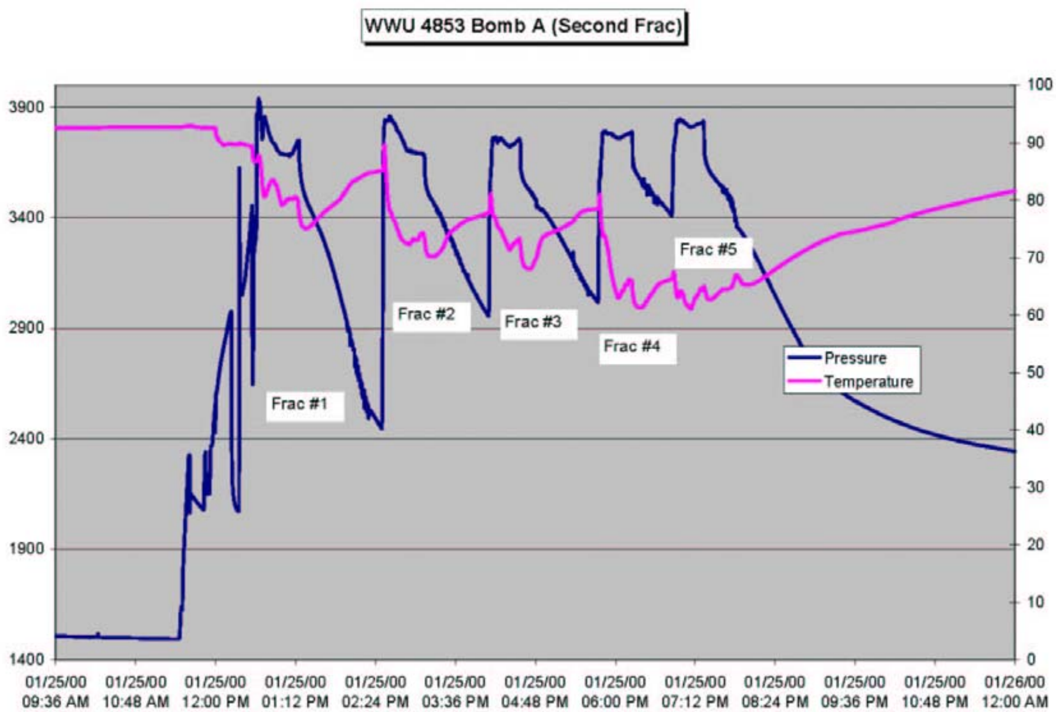

Fig. 7 - BHP & Temp Chart - WWU 4853 Lateral - Second Surgi-frac Completion Attempt 1/25/01

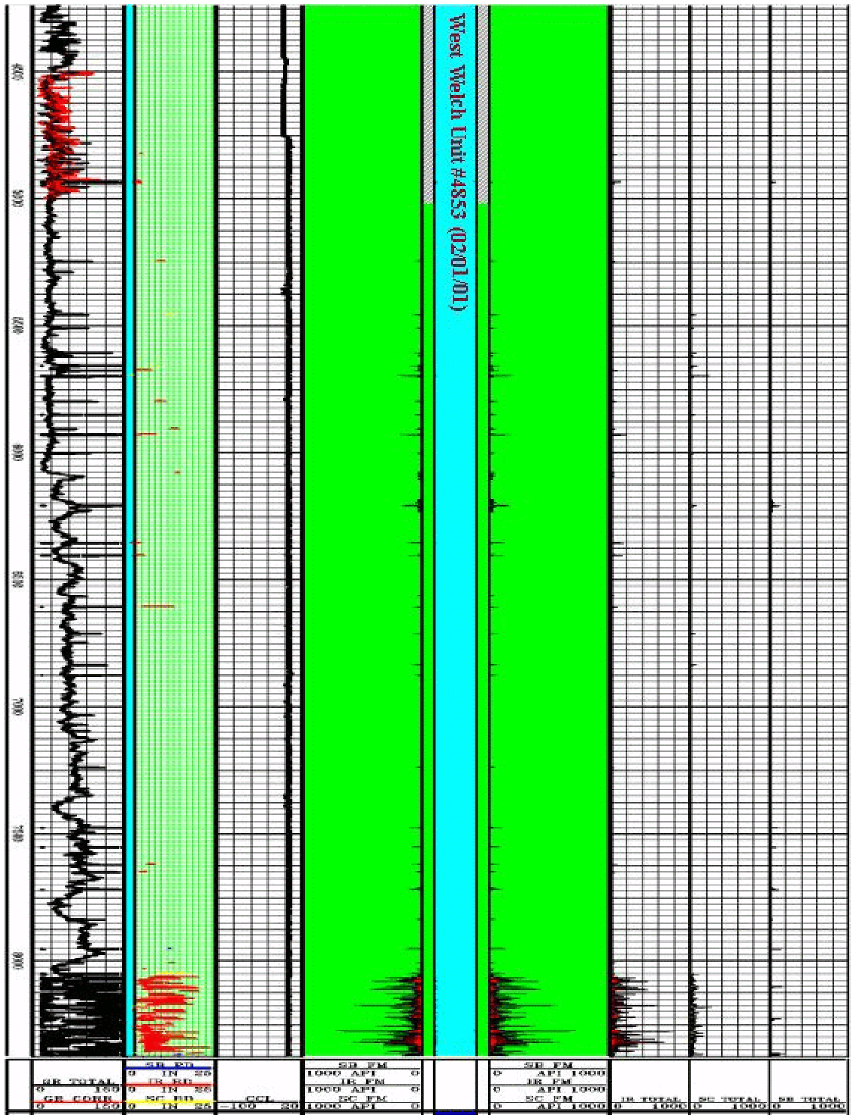

Fig. 8 - Radioactive Tracer Log - WWU 4853 Lateral - Run 2/01/01
After Second Completion Attempt

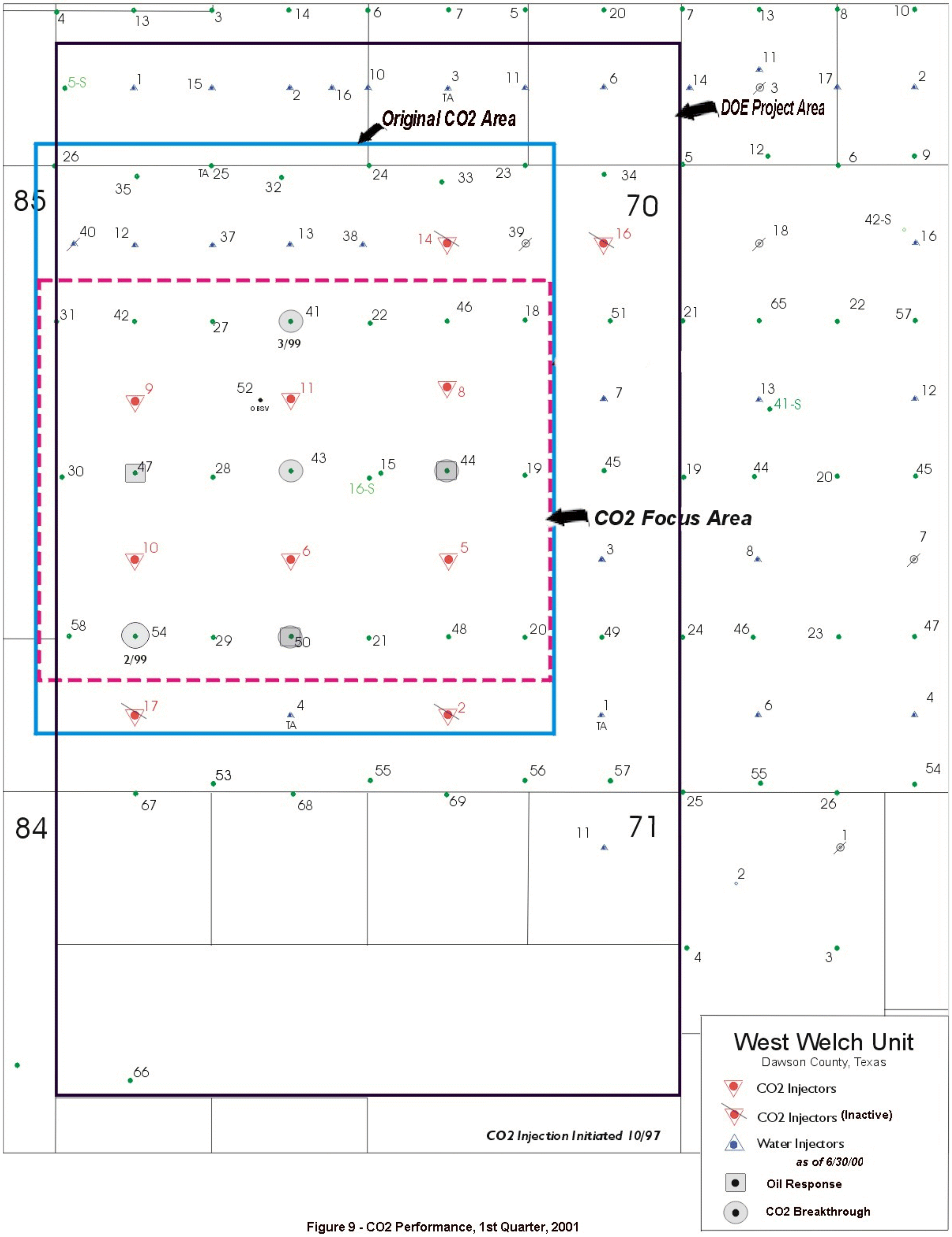

Figure 9 - CO2 Performance, 1st Quarter, 2001

TABLE 1
DRILLING AND COMPLETION ACTIVITY LOG
HORIZONTAL LATERAL—WWU NO. 4853
WELCH FIELD
DAWSON CO., TX

I. ORIGINAL VERTICAL WELL

1. Spudded 3/17/97
2. Drilled to TD 5050'
3. Set 5 ½ in csg @ 5050' Circulated cement to surface.
4. Perforated San Andres 4925-55' and 4973-79'
5. Acidized w/3000 gal HCL
6. Fraced 13,000# sand
7. Initial Potential 6/13/97: 47 BOPD; 310 BWPD; Gas tstm

II. HORIZONTIAL LATERAL

10/16/00

1. POOH with rods & tbg
2. Picked up 5 ½ in. csg scraper, RIH to TD
3. POOH
4. Set CIBP on wireline at 4795'
5. Pressure tested csg to 2000 psi

11/04/00

1. RIH w/ Baker Hughes whipstock and 4 3/4 in. starter mill.
2. Set whipstock at 4782' with 344 ° azimuth (az) orientation.

11/05/00

1. Milled 18 inches of 5 ½ csg
2. Circulated hole clean
3. RIH with 4 3/4 in. window mill and 4 3/4 in. watermelon mill
4. Completed milling window in 5 ½ csg
5. POOH and laid down mills
6. RIH with 4 3/4 in. Hughes Star 30 button bit, downhole motors and MWD steering tool.
7. Gyro oriented downhole assembly into window
8. Started drilling curve

11/06/00

1. Continued to drill curve. Became increasingly difficult to build angle. Appeared that whipstock rotated to right during milling operation. Well path was 7.4 ° az v. the 344° az target.
2. Installed motor assemble with bent sub angle. Finish drilling curve at 4999' with 348 ° az and 88 ° inclination (incline).
3. POOH with curve building assemble.

11/07/00

1. RIH with lateral drilling assembly.
2. Drilled lateral from 4999' to 5081' MD. (82' in 24 hrs)
3. Directional survey confirmed correct whipstock slide orientation at 342° az. (well path in top of curve had walked to the right before being corrected back to target)

11/08/00

1. Drilled lateral from 5081' to 5140'MD.
2. Drilling rate slowed. Pull bit and found inserts dislodged.
3. RIH with Hughes ST-382 rock bit and lateral drilling assemble.
4. Drilled lateral to 5832' MD. (692' in 24 hrs)

5. Well path at 5821' MD (4942' TVD) was 348° az and 91.8° incline.

11/09/00

1. Drilled lateral from 5832' to 6196' MD.
2. Changed bit.
3. Drilled lateral to 6235' MD. (403' in 24 hrs)

11/10/00

1. Drilled lateral to 6693' MD. (458' in 24 hrs)
2. Average fluid loss at 17 BPH.
3. Well path at 6628' MD (4941' TVD) was 350° az and 91.3° incline.

11/11/00

1. Drilled lateral to 6698' MD. (405' in 24 hrs)
2. Average fluid loss was 13 BPH.
3. Well path at 7030' MD (4930' TVD) was 345° az and 91.5° incline.

11/12/00

1. Drilled lateral to 7155'.
2. POOH to change bit and repair downhole motor.
3. Drilled lateral to 7480' MD. (325' in 24 hrs)
4. Well path at 7433' MD (4921' TVD) was 348° az and 92.6° incline.

11/13/00

1. Drilled lateral to 8053' MD. (573' in 24 hrs)
2. No fluid loss.
3. Well path at 8000' MD (4905' TVD) was 346° az and and 91.1° incline.

11/14/00

1. Drilled lateral to final TD of 8410' MD (4897' TVD).
2. Well path at TD was 345° az and 89.9° incline.
3. Circulated hole clean.
4. POOH with bottom hole assembly.
5. Well flowed while rigging down.

11/19/00

1. S/I pressure 110 psi.

11/20/00

1. MIRU well service unit for completion.

11/22/00

1. Logged lateral with Halliburton Well Service.

11/28/00

1. RIH with pressure bombs and Halliburton's Surgi-frac tool. Planned to fracture lateral in separate treatments at six different intervals in the San Andres.

11/30/00

1. Started frac treatment.
2. Toward end of first treatment unexpected pressure drop occurred.
3. After treating the second and third intervals at abnormally low pressures, aborted job and pulled up out of lateral.

12/01/00

1. POOH
2. Surgi-frac tool jet was washed out. Sent to Halliburton lab for exam.

12/04/00

1. RIH with tbg and bit.
2. Tagged fill at 8051'. TD is 8410'. (359' of fill)
3. Pulled up out of lateral.

12/05/00

1. Ran bit and tbg back in lateral,
2. Worked through sand bridge at 6785'.
3. Wash sand fill from 8088' to TD at 8410'.

12/06/00

1. POOH
2. RIH with Halliburton logging tool.

12/06/00

1. Logged lateral coming out of hole.

12/14/00

1. RIH with 2 7/8 in. tbg.

12/15/00

1. RIH with rods and pump.

12/16/00

1. Set pumping unit.

12/17/00

1. Connected electric power.

12/25/00

1. Well pumped/flowed 0 BOPD and 488 BWPD, gas not measured.

12/27/00

1. Well pumped/flowed 30 BOPD, 565 BWPD and 1306 MCFPD (GOR 2.3 MCF/BBL).

12/28/00– 1/21/01

1. Well on production (see Table 3).

1/22/01

1. Kill well with brine.
2. POOH w/rods and pump.

1/23/01

1. POOH w/ tubing.
2. RIH w/2-7/8 work string.
3. Tagged up @ 7434' (TD 8410'). Unable to circulate.

1/24/01

1. Reversed out scale from 7434- 8019'.
2. POOH w/ tbg.
3. RIH w/ pressure gauge and bottomhole Surgi-frac assemble.

1/25/01

1. Initiate Surgi-frac in five stages from 7850- 5298 ft(MD).
2. PUH to vertical section.

1/26/01

1. Opened well, flowed 70 bbl to tank.
2. POOH w/ tbg and tools.
3. RIH w/ 4 3/4 bit, jet sub and tbg.

1/27/01

1. Reversed out sand from 7759- 8019' and scale from 8019 - 8116'.
2. PUH to vertical section.

1/28-30/01

1. Shut down.

1/31/01

1. RIH TO 8116'.
2. Reversed out sand and scale from 8116 - 8410'.
3. POOH to vertical section.

2/01/01

1. Killed well with brine.
2. POOH w/ tbg.
3. RIH w/ radioactive logging tool and tbg to 8410'.
4. POOH logging.

2/02/01

1. RIH w/ tbg.
2. Pumped scale converter.

2/03/01

1. Swabbed 90 bbl.
2. Acidized w/ 3500 gal 20% CCA.
3. Flowed and swabbed back 100 bbl.

2/04-05/01

1. Shut down.

2/06/01

1. Pumped scale squeeze.

2/07/01

1. Killed well w/ brine.
2. POOH w/ tbg.

2/08/01

1. RIH w/ Reda pump and 2-3/8 tbg.
2. Started pump.
3. Final report.

Table 2

Treatment Summary
Initial Attempt 11/29/00
OXY-WWU 4853

Treatment Depth (md)	Stage	Fluid Volume (gal)	Prop in Formation (lb)	Average Concentration (lb/gal)	Rate (bbl/min)	Max. Surface Treating Pressure (psi)
8385'	4	9,968	1,888	0.30	18	8508
	5	2,001	141	1.03	18	7724
	6	2,005	2,225	2.01	18	7432
	7	2,028	4,403	3.01	18	7034
	8	1,727	5,213	3.00	18	6219
	9	1,985	5,415		18	6404
	Subtotal	19,714	19,285			
7850'	12	9,990	1,125	0.16	18	5905
	13	1,985	414	1.12	18	5639
	14	1,995	2,593	2.08	18	5524
	15	1,992	4,635	3.07	18	5580
	16	2,290	7,648	3.38	18	5787
	17	1,903	5,235		18	5835
	Subtotal	20,155	21,650			
7250'	20	9,974	1,584	0.20	18	5907
	21	1,993	495	1.13	18	5644
	22	1,996	2,703	2.06	18	5453
	23	1,785	3,780	2.89	18	5417
	24	1,042	2,704	2.53	18	4681
	25	1,726	4,106		18	5381
	Subtotal	18,516	15,372			
	Grand Total	58,385	56,307			

Notes:
1. Proppant for initial stage at each interval was 20/40 Sintered Bauxite
2. Proppant for subsequent stages was 20/40 resin-coated sand
3. Fluid is cross link gelled water (Deltafrac)

Table 3

Daily Well Test History
OXY-WWU 4853

Test Date	Oil (bbl)	Gas (mcf)	Water (bbl)	Casing Gas	Tubing Gas	Water Cut %	GOR
01/04/01	41	1206	610				
01/05/01	39	1389	572			93.6	35615
01/06/01	38	1335	526	1.4		93.4	35132
01/07/01	39	1396	504			93.0	35795
01/08/01	36	1330	463			92.8	36944
01/09/01	41	1476	481			92.1	36000
01/10/01	35	1483	469			93.0	42371
01/11/01	32	1421	453			93.4	44406
01/12/01	19	1003	363			95.0	52789
01/13/01	23	1323	398	300	1023	94.5	57522
01/14/01	23	1230	380	240	990	94.3	53478
01/15/01	23	969	391			94.4	42130
01/16/01	22	893	375			94.5	40591
01/17/01	10	426	178			94.7	42600
01/18/01	1	159	121			99.2	159000
01/19/01	4	227	209			98.1	56750
01/20/01	3	243	212			98.6	81000
02/15/01	0	131	1271			100.0	
02/16/01	0	67	1294			100.0	
02/17/01	4	40	1103			99.6	10000
02/18/01	0	124	33			100.0	
02/19/01	0	0	0			100.0	
02/21/01	0	70	871			100.0	
02/22/01	2	0	1180			99.8	0
02/23/01	7	248	1069			99.3	35429
02/27/01	2	12	273			99.3	6000
02/28/01	0	110	928			100.0	
03/01/01	0	295	974			100.0	
03/02/01	9	496	861			99.0	55111
03/03/01	9	555	882			99.0	61667
03/04/01	0	495	619			100.0	
03/05/01	10	1044	869			98.9	104400
03/06/01	4	559	867			99.5	139750
03/07/01	10	801	909			98.9	80100
03/10/01	7	456	933			99.3	65143
03/11/01	7	669	1001			99.3	95571
03/12/01	7	464	919			99.2	66286
03/13/01	19	706	981			98.1	37158
03/14/01	8	703	904			99.1	87875
03/15/01	19	674	945			98.0	35474
03/16/01	9	653	922			98.4	72556
03/17/01	9	653	922			99.0	72556
03/18/01	9	693	995			99.1	77000
03/19/01	9	691	992			99.1	76778
03/20/01	17	740	1016			98.4	43529

Table 4

Treatment Summary
Second Attempt 1/25/01
OXY-WWU 4853

Treatment Depth (md)	Stage	Fluid Volume (gal)	Prop in Formation (lb)	Concentration (lb/gal)	Rate (bbl/min)	Surface Treating Pressure (psi)
7850'	3	10,004	452	0.1	13.5	8044
	4	2,000	1,844	0.1-1.6	15.4	8563
	5	2,000	3,657	1.7-2.4	15.4	8593
	6	2,000	5,960	2.5-4.0	14.8	8795
	7	3,220	10,648	4.0-0.3	15.3	8883
	Subtotal	19,224	22,561			
7246'	10	8,650	2,076	0.4-1.7	15.9	8415
	11	2,100	4,184	1.7-2.7	15.8	8308
	12	2,150	6,429	2.8-4.3	16.0	8204
	13	2,145	3,918	4.3-0.8	15.8	8784
	14	1,520	57	0.4	14.9	8716
	Subtotal	16,565	16,664			
6525'	16	2,046	1,565	0.0-2.2	15.0	7139
	17	8,750	4,214	2.3-3.1	16.2	7829
	18	1,298	6,546	3.2-4.4	17.2	7731
	19	1,567	8,287	4.4-1.3	17.3	8063
	20	1,662	961	0.9-0.5	17.5	8431
	Subtotal	15,323	21,573			
5906'	23	2,019	1,766	0.6-2.3	14.9	7137
	24	8,250	3,982	2.3-3.4	16.0	7486
	25	1,289	6,079	3.4-3.9	16.3	7239
	26	1,579	13,530	4.0-1.1	16.3	7666
	27	1,672	611	0.7-0.3	16.5	7940
	Subtotal	14,809	25,968			
5299'	30	1,996	1,926	0.8-2.2	15.8	7011
	31	8,580	4,160	2.2-3.0	16.6	7192
	32	1,279	6,296	3.1-5.3	16.8	6976
	33	1,569	11,745	2.4-1.2	16.7	7415
	Subtotal	13,424	24,127			
	Grand Total	79,345	110,893			

Notes:
1 Proppant for initial stage at each interval was 20/40 Sintered Bauxite
2 Proppant for subsequent stages was 20/40 resin-coated sand
3 Fluid is cross link gelled water (Deltafrac)

Table 5

CO2 Focus Area Performance
First Quarter - 2001
West Welch Unit DOE Project
Dawson County, Texas

		JAN	FEB	MAR	1st Qtr
Injection					
	Average CO_2 injection rate (mcfd)	1211	1390	3101	1958
	# of Injectors on CO_2	5	5	6	
	Average rate per injector (mcfd)	242	290	527	367
	% HCPV injected	0.3%	0.1%	0.2%	0.6%
	Cum % HCPV injected	10.7%	10.8%	11.0%	11.0%
	Average water injection rate (bwpd)	192	186	0	124
	# of Injectors on water	1	1	0	
	Average rate per injector	192	186	0	124
	Water+CO_2 % HCPV injected	0.2%	0.2%	0.3%	0.7%
	Water+CO_2 Cum % HCPV injected	12.2%	12.4%	12.7%	12.7%
Production					
	Base oil production (bopd)	131	130	129	130
	Actual oil production (bopd)	178	180	186	182
	Incremental oil production (bopd)	47	50	57	52
	Cum % OOIP				
	Gas production (mcfd)	348	207	N/A	N/A
	Gas production as % injection	29%	15%	N/A	N/A
	Base WOR	13	13	13	
	WOR	5.3	5.2	5.1	5.2