TUBINGLESS PCP APPLICATIONS FOR SLIMHOLE WELLS

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ABSTRACT

The Sacatosa field is located in Maverick County, approximately 19 miles East of Eagle Pass, Texas. Production has been mainly limited to the San Miguel –1 reservoir. Conoco discovered this sandstone formation (1135 to 1768 feet deep) in December 1956.

Production wells were typically drilled using one string of 4 %-inch, J55, 9.5 lb./ft. casing. Completion practices typically did not always cement back to the surface. After many years of service, well casings have failed. It has been common practice to extend the productive life of these wells by cementing in 3-inch or 2 7/8-inch liners. However, 1.9-inch tubing is then required to run insert sucker rod pumps. Because of the thin wall thickness of this pipe, there have been numerous tubing failures. Additionally, approximately 10 years after running a liner, a well typically starts to have liner problems.

A unique application of the progressing cavity pump (PCP) technology was tried in a pilot well by running this equipment without tubing. After the first success, three other installations were tried. This paper will discuss these installations and provide further discussion on the application of PCP technology to other wells.

INTRODUCTION

The Sacatosa field, or Chittim lease, is located in South West, Texas, in Maverick county. Figure 1 shows a map with the field highlighted. It is approximately 19 miles East of Eagle Pass, Texas. Production has been mainly limited to the San Miguel –1 reservoir. Conoco discovered this sandstone formation in December 1956. The depth of the San Miguel-1 ranges from 1135 to 1768 feet in the current production lease. The reservoir is characterized as a coarsening-upward sequence of silty to sandy shale, siltstone, and fine-grained to very fine-grained sandstone. Since 1956, there has been approximately 1303 wells drilled which consisted of 683 producers, 596 injectors, and 24 service wells. The lease is presently developed on 10-acre spacing using 20-acre 5-spot waterflood patterns. Waterflooding under this pattern development began in 1966. The success of this first phase development was followed by field wide waterflood expansions in 1970, 1975, and 1983. There are approximately 488 producers, 246 injectors, and 10 service wells currently in operation. Current production is approximately 1900 bopd and 6000 bwpd.

These wells were typically drilled using one string of 4 %-inch, J55, 9.5 lb./ft. casing. Depending on when the wells were drilled, the completion practices typically did not always cement back to the surface, since it was determined that there were no fresh water zones in the area. Due to the shallow nature completion practices of these wells, the location of a shallow fault zone, and an erratic casing cathodic protection system, casing failures have occurred in numerous wells in the field. It has been common practice to extend the productive life of these wells by cementing in 3-inch or 2 7/8-inch liners. However, 1.9-inch tubing was then required to run insert sucker rod pumps for producing wells.

While running the liners extended the well life, the thin walled, 1.9-inch tubing typically caused frequent tubing failures. Furthermore, the liners could not prevent the shearing or near surface collapsing of these wells. Thus, after about five to seven years, the liners started having problems. After about 10 years, the liners failed requiring the well to be plugged.

What was required was an artificial lift method that could be installed in existing liners. It had to be a tubingless completion to reduce the operating costs associated with these wells. It also had to be able to handle approximately four to 10 bopd and 20 to 80 bwpd along with the gas produced through the pump when an isolation packer was installed above the perforations.

We discussed a variety of methods, including high compression ratio sucker rod pumps. However, we selected the sucker rod driven progressing cavity pump (PCP) method since it fulfilled all these requirements. It also had additional capabilities to handle some solids that are routinely produced and could be easily adapted to variable production with a surface controller connected to the electric motor.

PCP SYSTEM DESIGN

With the method selected, we discussed feasibility and solicited proposals from a variety of companies to provide the necessary pump system. We selected one company that could provide the equipment. We worked together to review candidate wells, select the required equipment, and designed the downhole system, including selecting the method for holding the pump downhole at the required depth. This method consisted of using an available downhole pump anchor. This anchor does not require the typical seating nipple. It was able to set using a unique vertical action of the rod string to set and pack-off the well. It also can be released and reset without rotating or being pulled from the well.

Figure *2* shows the schematic for the installed PCP system for the first selected well, #43-54. This well was selected since it was recently lined, it had four well failures in 1999 and the beam pump system was not adequately sized to pump the well down. The installation had three sinker bars that were installed below the perforated fluid intake nipple and pump. These were installed to provide a downward force to help set the pump anchor. The downhole pump was spaced out using D grade, 7/8" sucker rods with spinnable rod guides. These were installed using two guides per rod to prevent the rod string from contacting or wearing a hole in the liner.

The surface equipment included a well head drive and a 7.5 horsepower electric motor. A Vector variable speed drive (VSD) was installed at the power pole and connected to the motor to allow better control over the pump system to match well inflow. Since the pump anchor prevented obtaining the fluid level in the well, we relied on a number of VSD and surface operational parameters to determine how well the system was operating and whether or not there needed to be any speed adjustments. Photographs of the some of the equipment and the installed system are shown in Figures *3* and 4.

FIRST FIELD TEST

The first well production results are presented in Table **I.** The well flowed approximately 5 bopd and 35 bwpd prior to the installation. The main surface operating parameters that could be measured are presented in this table. It should be noted that once the downhole pump anchor was installed, the packer seal assembly prevented taking pump submergence measurements.

At the beginning of the test it was noticed that there was not a significant change from the prior flowing production rate. Additionally, the production measurements did not change with the changes in PCP operating speed. There was one time at the beginning that the PCP was stuck; but we were able to free it without pulling the well. After about three weeks of operation, the pump was stuck again. It could not be worked free, so the well was pulled. Also, after evaluating the pump performance and the lack of changes with motor speed changes, it was decided that the pump anchor had worked free and the well was still flowing past the pump.

The pump was pulled, worked free, and reran. When the installation was reran, the surface casing line was opened to determine when the anchor was set. If it were not set, the well would continue to flow up the backside. When it was properly set, the well would not flow up the backside and it discharged out of the tubing side. Additionally, the surface flowline pressure increased to approximately 50 psi. This pressure remained constant at about 10 psi during the flowing condition.

After properly setting the pump, the production significantly increased from about 5 bopd to ***28*** bopd and from about 35 to 45 bwpd. During the next few days of monitoring the well, the oil and water rates decreased as the well pumped down. It was noted that the rated responded to the changes in pump speed, as expected.

After about three weeks, the pump reached a stable condition and the speed was adjusted to provide about 45% efficiency. Comparing all the monitoring parameters, the pump volumetric efficiency (combined well test rate divided by the pump displacement) provided the best indication of operating condition. Since this installation, there have been no well failures nor stuck pump problems.

NEXT INSTALLATIONS

Based on the success **of** the first well, three other wells were selected. These wells were more of a challenge since they were lined from three to seven years ago. There was one well, 37-58, that the liner already started to collapse and allowed the highly pressured Olmos water zone to cause the well to flow (OFL). The other wells had problems with the cemented liners. This also allowed leaks of the highly pressured Olmos zone which made it difficult to match the production rate of the beam pump system to the capacity of the well. Mixing of the Olmos water also caused downhole-scaling problems which contributed to the frequent failure of these wells. Two of the wells, 04-26 and 43-57, had so many problems, that there were temporarily shut-in (OTS) due to the high operating costs.

Table II provides a comparison of the background information on the wells. The normal well test and the current well test prior to the tubingless PCP installations also are presented.

The daily production reports from these wells are presented in Tables III, IV, and V, for wells 43-57, 04-24, and 37-58, respectively. The greatest increase in production was shown by well 43-57. After slowly starting the well, and increasing the pump speed, the well finally increased to a rate of about 21 bopd and 40 bwpd. This exceeded the prior normal test, so it will continue to be monitored to see if the well capacity changes. This increase in oil production also was significant since the well was temporarily shut-in for over three months when it last failed.

The well 04-26 was slowly started and the speed adjusted until the well was pumped down (the volumetric efficiency was less than 50%). The well responded, as expected, to the changes in motor speed. After pumping the well down, and reaching stable condition on 02/18/01, the motor was slowed back down to 200 rpm to bring the efficiency to about 42%. The well will continued to be monitored to see if further speed reductions are required. This well was brought back to the normally expected production of 8 bopd but with a slight increase in water from 15 to 26 bwpd.

The well 37-58 quickly responded to the PCP installation. Stabilized production increased from 2 bopd prior to the installation to about 6 bopd after. The pump efficiency was stable at about 45% after less than one week of testing. This well will continue to be monitored since the liner collapse at about 985' prevented running the pump very deep. Thus, it will be evaluated to see if there may be any expected production improvement if a dip tube could be run closer to the perforations.

OTHER APPLICATIONS

The current tubingless completions were proven to be unique solutions to these problem wells. This technique provided a production increase in all of these wells. The use of this technique will reduce operating expense and prevent the frequent well failure. However, the most important aspect of this solution was it rescued these wells from plugging. Thus, other wells will be considered, on a case by case basis, for the use of this technique at the Sacatosa field.

While this technique was beneficial for these problem wells, it could be extended to other applications. One example is to do zone tests by isolating different zones. The PCP on the pump anchor can then be placed in the well uphole from the isolation packer. Since the anchor can seal off between the lower packer (or act as the lower packer itself), and the pump intake, the selected zone can be tested without the need for tubing.

Another application could be for testing new, slimhole/test drilled wells that will not flow. Using the normally available anchor sizes of 2 3/8", 27/8", or **3** ½" could provide some planning for slimhole drilling for exploration or delineation purposes. Combining **this** with the capacity of the PCP for handling gas, solids, paraffin, etc. would allow testing to depths of about 5000 ft. with sucker rod driven systems.

CONCLUSIONS

1. A unique artificial lift method was developed by combining available technology of the pump anchor with the attributes of the PCP technique to solve problems in slimhole, liner wells.

2. This method not only provided a production increase and an operating expense decrease; it effectively rescued these wells from plugging.

3. The technique developed for these wells will provide for increase use on other problem wells in the Sacatosa field.

4. This method could be extended to other applications, such as zone testing or slimhole drilled wells.

ACKNOWLEDGEMENTS

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Table 1
Progressing Cavity Pump Monitoring
Well 43 - 54

Date	Pump Submerg.	Amps	Torque	RPM	Oil Rate (BOPD)	Water Rate (BWPD)	Pump Displ. (0.20 * RPM)	Pump Efficiency	Flowline Pressure
5/12/2000		5.3		350	6.3	44.8	70	73%	
5/16/2000		4.8		350	4.9	36.5	70	59%	
5/18/2000		4.8		350	4.9	36.5	70	59%	10
5/19/2000		5.2		400	4.9	35	80	50%	
5/20/2000				400	4.9	35	80	50%	
5/21/2000				400	5.4	35.5	80	51%	
5/22/2000	Found	stuck		400	4.9	35	80	50%	
5/30/2000	Restarted	5.8		400			80		
5/31/2000		5.4		400	4.4	32.5	80	46%	
6/1/2000		5.2		400	4.4	33	80	47%	20
6/2/2000		5.5	16.5	450	4.9	32	90	41%	
6/2/2000	4:30PM	4.3	13.5	300	Reduced RPM's				
6/3/2000				300	5.4	32.5	60	63%	
6/4/2000				300	3.9	31.5	60	59%	
6/5/2000				300	4	31.4	60	59%	
6/6/2000		4.2	14	300	4.9	32.5	60	62%	
6/6/2000	1:00PM	5.2	15.5	400	Increased RPM's				
6/9/2000	Found	stuck		0	4.9	31.6	0		
7/6/2000		6.3	35	445	28.2	45.3	89	83%	
7/6/2000		6.3	35	445	27.3	42.2	89	78%	50
7/7/2000		6.3	35	445	22.4	39.9	89	70%	58
7/8/2000				445	20.6	38.4	89	66%	
7/9/2000				445	18.8	35.1	89	61%	
7/9/2000				445	17.8	34	89	58%	
7/10/2000		6.1	34	445	16.5	32.1	89	55%	82
7/12/2000		5.5	30	400	13.3	28.1	80	52%	50
7/13/2000		5.5	29	400	12.8	26.6	80	49%	50
7/14/2000				400	12.3	26.1	80	48%	
7/15/2000				400	12.5	26.1	80	48%	
7/16/2000				400	12.3	24.7	80	46%	
7/17/2000		5.5	29	400			80	0%	50
7/18/2000		5.5	29	400			80	0%	58
7/19/2000		5.5	29	400			80	0%	50
7/20/2000		5.25	27.5	350	10.8	22.7	70	48%	50

Table 2
Sacatosa Tubingless PCP Wells
(First Batch after test on 43- 54)

Well No.	TD	PBTD	Liner Size	Liner Depth	Perf Zone	Normal Well Test	Current Well Test	Comments
04-26	1586'	1530'	2 7/8"; 6.5#	surf to 1471'	1480' to 1511'	8.0 o 15 w		
37-58	1360'	1344'	3.5"; 8.81#	surf to 1254'	1273' to 1306	5.0 o 10 w	2 o; 40 w	May have tight spot (Old one @ 1082')
43-57	1443	1476	3.5"; 8.81#	surf to 1418	1438' to 1468'	16 o 30 w	OTS	

Table 3
Progressing Cavity Pump Monitoring
WELL 43 - 57

Date	Pump Submerg.	Amps	Torqw	RPM	Oil Rate (BOPD)	Water Rate (BWPD)	Pump Displ. (0.40 * RPM)	Pump Efficiency
11/20/2000	Last test before failure				16.3	29.6	0	#DIV/0!
2/2/2001		7.25	13.5	200	8.8	40.4	80	62%
2/2/2001		7.25	13.5	200	11.7	53	80	81%
2/5/2001		7.25	13.5	200	19.2	46.4	80	82%
2/7/2001		7.25	13.5	200	21	45.3	80	83%
2/8/2001		7.9	17.9	250	24.8	45.7	100	71%
2/8/2001		7.7	16.5	250	23.4	42.3	100	66%
2/9/2001		7.7	16.5	250	22.7	41.9	100	65%
2/10/2001				200	20.7	39.5	80	75%
2/14/2001				250	21.7	40.9	100	63%
2/16/2001				250	20.7	40.8	100	62%
2/18/2001				250	20.9	39.4	100	60%

Table 4
Progressing Cavity Pump Monitoring
WELL 04 - **26**

Date	Pump Submerg.	Amps	Torque	RPM	Oil Rate (BOPD)	Water Rate (BWPD)	Pump Displ. (0.40 * RPM)	Pump Efficiency
2/3/2001	1404'	7.2	11.4	250	6.9	61.1	100	68%
2/3/2001	"	7.6	11.4	250	6.9	61.1	100	68%
2/3/2001	"	7.6	11.4	250	7.4	55.2	100	63%
2/4/2001	"	7.6	11.4	248	8.8	56.5	99.2	66%
2/5/2001	'	7.4	13.3	250	8	57	100	65%
2/6/2001	'	7.4	13.3	250	7.9	50.8	100	59%
2/7/2001	'	7.7	15.6	300	NO	TEST		
2/8/2001	'	7.7	15.4	300	12.7	57.4	120	58%
2/9/2001	'	7.6	16.2	300	11.3	50.3	120	51%
		7.6	16.2	300	10.9	45.9	120	47%
2/10/2001	'	8.1	18.2	300	9	37.6	120	39%
	'	8.1	18.2	300	9.6	39.4	120	41%
2/11/2001	"	8.1	18.2	300	8.8	34.6	120	36%
		8.1	18.2	300	10.7	44.7	120	46%
2/17/2001	"	**8.1**	18.5	298	7.8	*26.2*	119.2	*29%*
2/18/2001	"	8	18.1	*297*	*7.8*	26.8	*118.8*	29%

Table 5
Progressing Cavity Pump Monitoring
Well 37 - 58

Date	Pump Submerg.	Amps	Torque	RPM	Oil Rate (BOPD)	Water Rate (BWPD)	Pump Displ. (0.40 * RPM)	Pump Efficiency
2/3/2001		6.9	23.4	200	6.3	39.4	80	57%
2/3/2001	"	6.9	23.4	200	4.9	38	80	54%
2/3/2001	"	6.9	23.4	200	5.9	39.4	80	57%
2/4/2001	"	6.9	23.4	200	4.9	37.5	80	53%
2/4/2001	"	6.9	23.4	200	5.4	38.9	80	55%
2/5/2001	"	7.1	12.3	250	5.4	39.5	100	45%
2/6/2001	"	7.1	12.1	250	6	41.1	100	47%
2/7/2001	"	7.1	12.1	250	6.4	40.9	100	47%
2/8/2001	"	7.1	12	250	5.3	39.9	100	45%
2/8/2001	"	7.1	12	250	5.8	40.3	100	46%

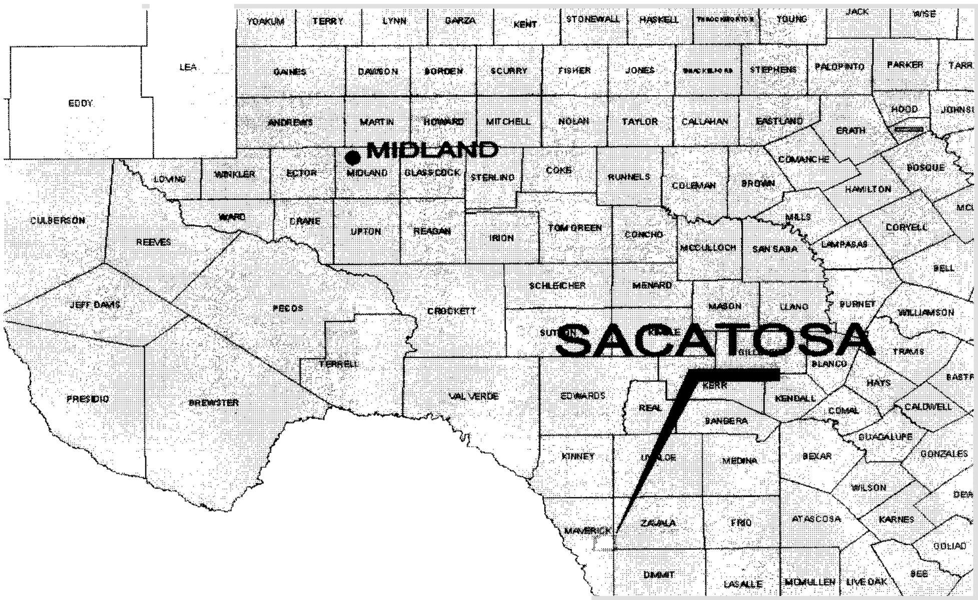

Figure 1 – Sacatosa Field Map

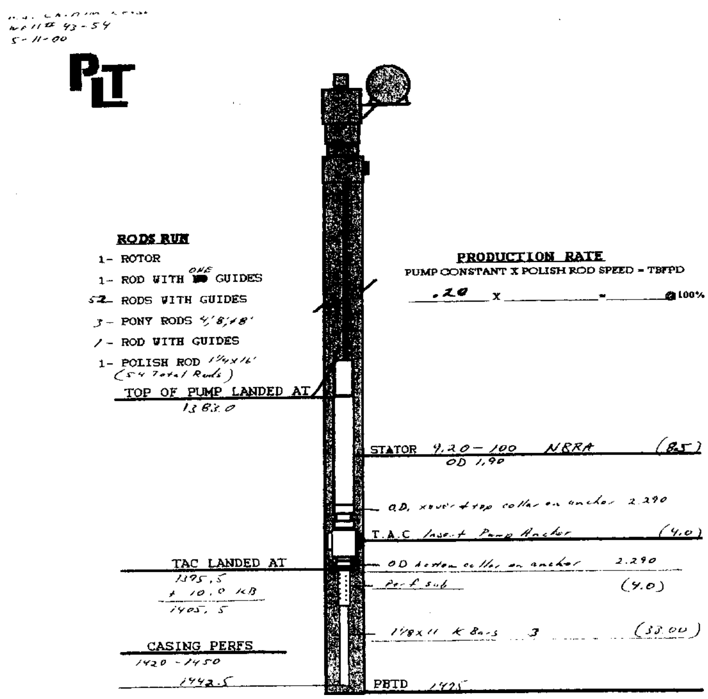

Figure 2 - **Well** 43-54 Schematic of Downhole Tubingless PCP System

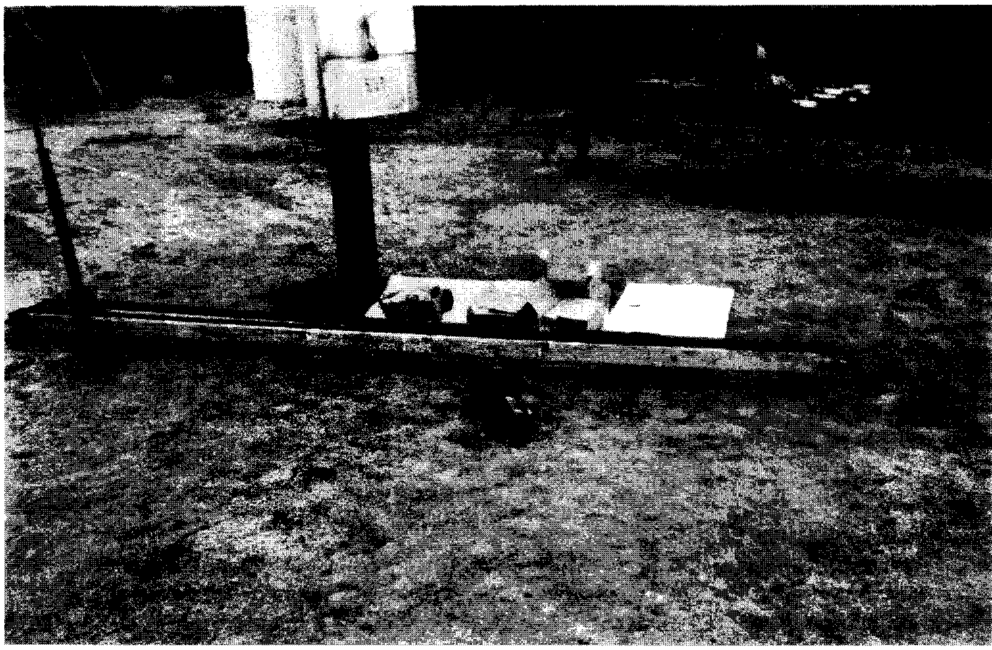

Figure 3 - Photgraph of the PCP Pump and Pump Anchor in the Shipping Crate, the Drive and Motor Along with the Guided Sucker Rods on the Transport in the Background, and the Power Pole with the Main Breaker Box on the Right and Variable Speed Drive Box on the Left

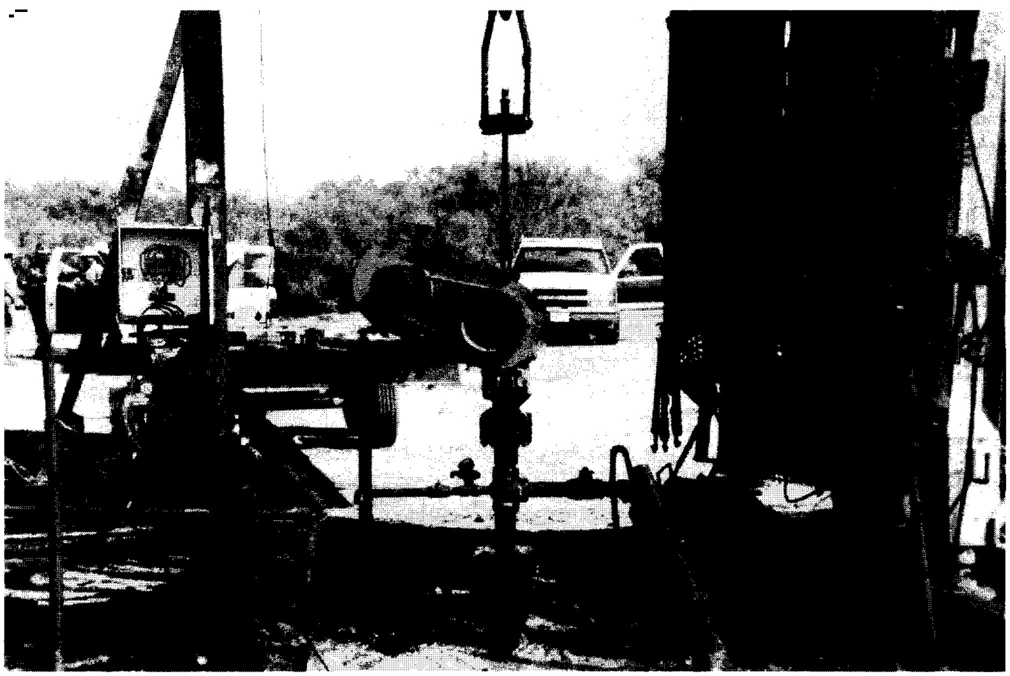

Figure **4** – Final Installation of PCP Surface Equipment, Prior to Rigging Down and Clean Up, with Motor Sheave Guard Removed for Clarity