DECREASING LOADING BY DECREASING PUMP CAPACITY CAN PROVE VALUABLE

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INTRODUCTION

Operating expenses in the Moss Unit were reduced by checking equipment designs and reducing equipment loading where possible.

The South Cowden, Moss Unit is located in the South Cowden Field, five miles southwest of Odessa, Texas and is operated by Union Oil Company of California. The water injection began in the Grayburg-San Andres zones in 1961. For the six years from 1980 through 1985 the unit averaged 69 rod pumping wells and 41 injectors. The gas contains 30,000 PPM H_2S and the corrosion is considered severe. Truck treating is the method of corrosion control and no significant changes in corrosion control have been made in the last six years.

CHANGES WERE MADE

In 1981 we gained access to a computer with API RP11L design calculations for sucker rod pumping. This made it possible to easily check all our wells and make sure they fell within design limitations. The study showed all our wells to have adequate to excessive pump displacements and some of the wells to have equipment overloads. It was concluded we could reduce our pump capacities bringing all our wells within disign limits and still pump our wells off. Roughly, our design limits for rods were less than 90% of the maximum from the API Goodman Diagram. Pumping Unit torques and structures were considered acceptable at 100% of rating.

In 1981 we slowed down 46 wells for $11,100, 1982 4 wells for $900, 1983 23 wells for $8,200, 1984 1 well for $300, and 1985 0 wells for a total of $20,500. We try to run all our wells between six and ten strokes per minute. As our downhole pumps were pulled they were downsized where possible. We downsized seven in 1981, nine in 1982, six in 1983, one in 1984, and two in 1985. The pumps being pulled were reused or their parts were reused in other pumps. Operating expenses did not increase because the wells had to be pulled anyway and the old pumps were not wasted. In addition as the wells were pulled, six of the largest possible rods were put on top of the pump (2 3/8" - 7/8" rods, 2 7/8" - 1" rods). I estimate the rods to have been added to 40 wells at a cost of $11,400. We are still adding rods as we pull the wells. However, the old rods were recycled and many of the newly installed rods were inspected used rods so the unit really did not absorb this large of expenditure.

In addition, two procedures were rigidly enforced. All rods were made up with the circumferential displacement method and rod tongs were set every ten connections or at each taper. A combination lubricant and corrosion inhibitor was used on each connection. The second procedure was fluid levels were shot and evaluated monthly. A fluid level between 100 and 500 feet above the pump was acceptable. If the fluid level was more than 500 feet above the pump immediate action was taken to lower the fluid level and to make sure corrosion inhibitor came in contact with our downhole equipment. Normally this entailed tagging bottom for a short period of time, changing the pump or in some cases treating with weighted inhibitor. If the fluid level was below 100 feet the pumping time for the well was decreased. The attached Figure 9 shows that no significant oil production was lost. In addition, individual well test curves were closely monitored. They showed no significant loss except in well #17-9 when the fluid level was at 500'. We increased our run time on this well keeping the fluid level between 100' and 300'. This eliminated the production loss.

EFFECTS ON SUBSURFACE EQUIPMENT

The effects of these changes were surprising. Figure 1 shows rod parts fell from 23 in 1981 to 0 in 1984. Figure 2 shows pump changes went from 24 in 1981 to 9 in 1984. Figure 3 shows total subsurface expenses dropped from $147,928 in 1981 to $19,475 in 1984 (including hot oiling). Figures 3 and 4 show the breakout between maintenance and materials. In 1981 it was necessary to replace two tubing strings and one rod string. Since our program began we have not replaced a string of tubing or rods. The changes made have reduced subsurface expenses from a 1980 plus 1981 average of $109,900/yr to a 1983 plus 1984 average of $28,800/yr. The decrease of $81,000/yr will pay out our $31,900 investment in five months.

EFFECTS ON ELECTRICAL CONSUMPTION

These changes also resulted in reduced electrical consumption. In 1983 a study was done on the electrical savings on nine wells. In this study, twice the recommended API RP11L polish rod horsepower was used as recommended horsepower. This was compared to nameplate horsepower. Various combinations of changes were made, including the reduction of nameplate horsepower, reducing the strokes per minute, and varying run times. One example of the changes made is as follows:

1) Well #6-1 had a 15 HP 1200 RPM motor running the pumping unit 11 SPM and operating 25% of the time. It was changed to a 5 HP 900 RPM motor running the pumping unit at 8 SPM and operating 33% of the time.

2) Well #2-7 had a 50 HP motor running the pumping unit 8.75 SPM and operating 100% of the time. The 15 HP motor from Well #6-1 was placed on this well running the pumping unit at 5.5 SPM and operating 46% of the time.

3) Well #20-2 had a 75 HP motor running the pumping unit at 8.5 SPM and operating 100% of the time. It was replaced by the 50 HP motor from #2-7 which ran the pumping unit at 6.7 SPM and operated 72% of the time.

4) The 75 HP motor was placed in stock to be used at a later date.

A kilowatt hour meter was used to measure energy comsumption before and after the changes were made. The changes on each well included some combination of reduced name plate horsepower, reduced strokes per minute, and varying run times. The attached table, Figure 6, shows the reductions in equipment loading and energy savings. Our study concluded that the changes made resulted in a electrical cost reduction of $563.41/month (431 KWH/day) and a payout of the $7,077.38 initial investment in thirteen months.

EFFECTS ON PUMPING UNIT FAILURES

One would expect to see a decrease in both the numbers and cost of pumping unit failures as loads are decreased. This is not what we saw. Before we began slowing down units in 1981 we had a large increase in bearing and wrist pin failures that lasted for three years. In 1980, we changed alot of personel. Although we are not sure of the maintenance program before, after 1980 we expected the pumpers to grease their own units. In September 1983 we began contracting the greasing of 320 and larger pumping units. One can see on Figures 7 and 8 that a decrease in failures correspond closely with the initiation of contracting our greasing. This implies the increase in bearing failures to be a result of not effectively greasing our pumping units. One man alone should not be expected to effectively grease large units. We do feel there is a valuable lesson to be learned from our experience. A good program for greasing pumping units is mandatory.

CONCLUSION

The program of reducing loading by decreasing pump capacity but still pumping our wells off has been an effective way of reducing expenses. In the case of the Moss Unit, the majority of our cost reduction came in subsurface failure reductions. Electrical savings have resulted from this program. A good program for greasing pumping units is mandatory.

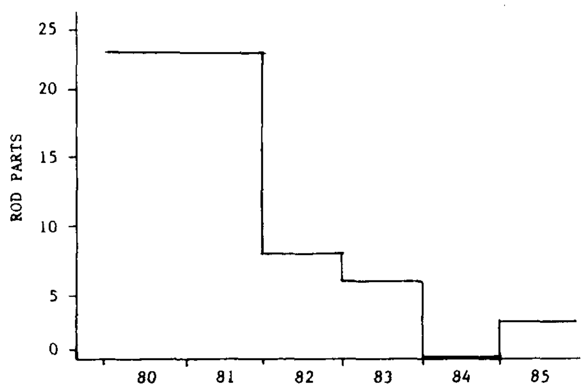

Figure 1 - Rod parts vs. time

		MOSS UNIT				
	1980	1981	1982	1983	1984	1985(9 Mo.)
Number Rod Pumping Wells	71	76	66	67	67	67
Rod Parts	23	23	8	6	0	3
Pump Changes	18	24	21	14	9	8
Tubing Leaks	2	4	6	6	2	2
Other		Replace two tbg strings and one rod string			1 polish rod part	

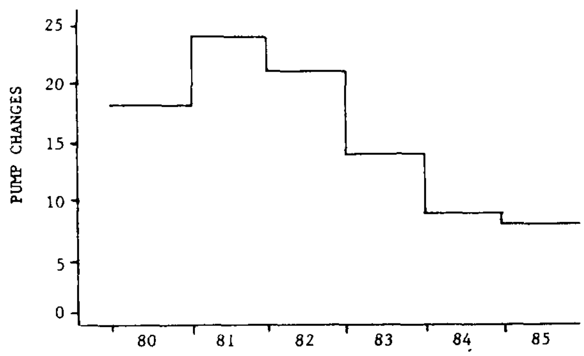

Figure 2 - Pump changes vs. time

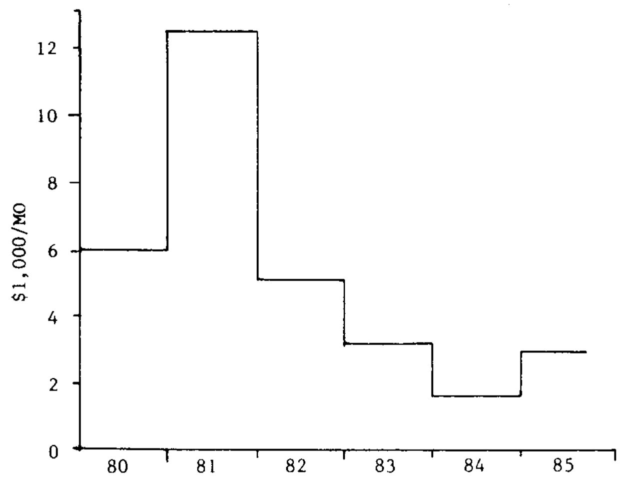

Figure 3 - Subsurface expenses vs. time
(total subsurface expenses)

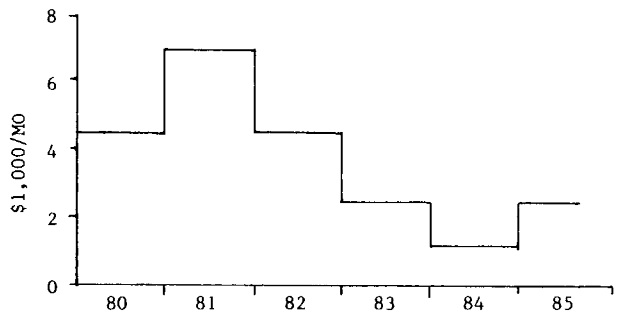

Figure 4 - Subsurface expenses vs. time
(subsurface maintenance)

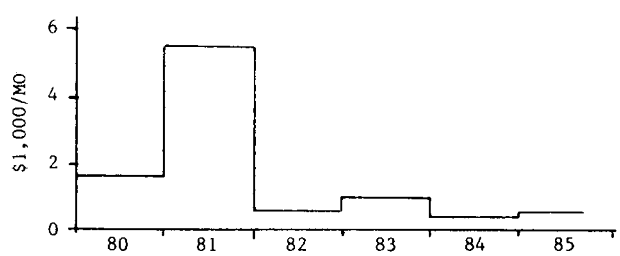

Figure 5 - Subsurface expenses vs. time
(subsurface materials)

MOSS UNIT WELL NO.	TEST BOPD/BWPD	CALC. 100% PUMP CAPACITY BPD/ON HAND	SPM	% CLOCK	CALCULATED STRESS % TAPER 1st%	2nd%	3rd%	CALC. GEARBOX LOADING %	CALC. STRUCTURE LOADING %	CALC. HORSEPOWER	NAMEPLATE HP	KWH/DAY	$/MONTH SAVED @ 0.043/KWH
2-2	8/16-7/17	68 - 46	11 - 8	50 - 50	70 - 66	78 - 74		43 - 41	? - ?	5 - 3	20 5	41 - 36	6.54
2-7	14/36-9/50	180-158	8.75 - 5.5	100- 46	84 - 72	92 - 79		90 - 69	64 - 58	24 - 13	50 - 15	144- 69	98.04
6-1	4/11-3/12	78 - 55	11 - 8	25 - 33	64 - 60	67 - 63		63 - 53	107-102	6 - 4	15 - 5	16 - 18	(2.61)
9-8	5/7 - 7/10	36 - 22	15 -12	70 - 60	72 - 69	80 - 77		**37 - 37**	89 - 88	3 - 2	10 - 5	33 - 33	0
14-11	4/4 -3/5	33 - 30	11 -10	25 - 33	57 - 57	61 - 60		47 - 46	? - ?	3 - 3	15 - 5	54 - 21	43.14
17-15	4/126- 4/108	211-147	10-7.2	100- 83	91 - 80	93 - 81		73 - 57	52 - 47	21 - 13	40 - 20	295 - 168	166.01
20-2	46/266 - 40/140	484-378	8.5 - 6.7	100- 72	80 - 73	82 - 71	86 - 80	65 - 49	53 - 50	44 - 31	75 - 50	423 - 263	209.15
20-4	26/9-24/10	78 - 66	12 -10	60 - 43	85 - 82	92 - 88		52 - 49	108 -105	7 - 5	20 - 10	65 - 35	39.22
21-5	6/7-6/7	17 - 10	9.5 - 6.75	69 - 75	67 - 63	72 - 70		23 - 22	? - ?	2 - 1	10 - 5	35 - 32	3.92
TOTAL											255 - 120	1106 - 675	563.41

Figure 6 - Moss Unit cost reduction (before and after)
South Cowden Field - Odessa area

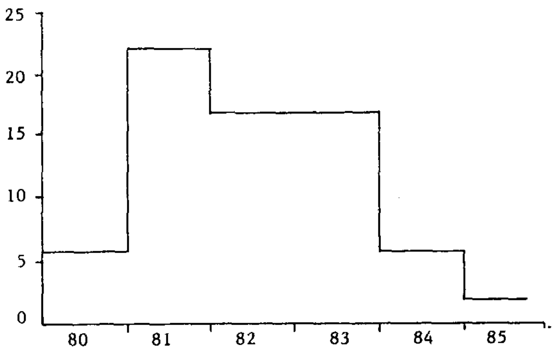

Figure 7 - Pumping unit failures vs. time

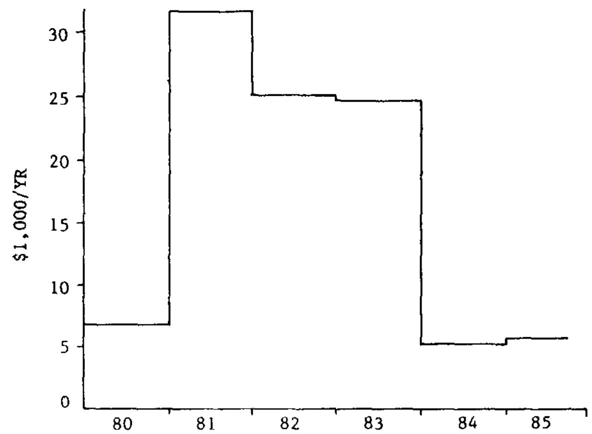

Figure 8 - Cost pumping unit failures vs. time

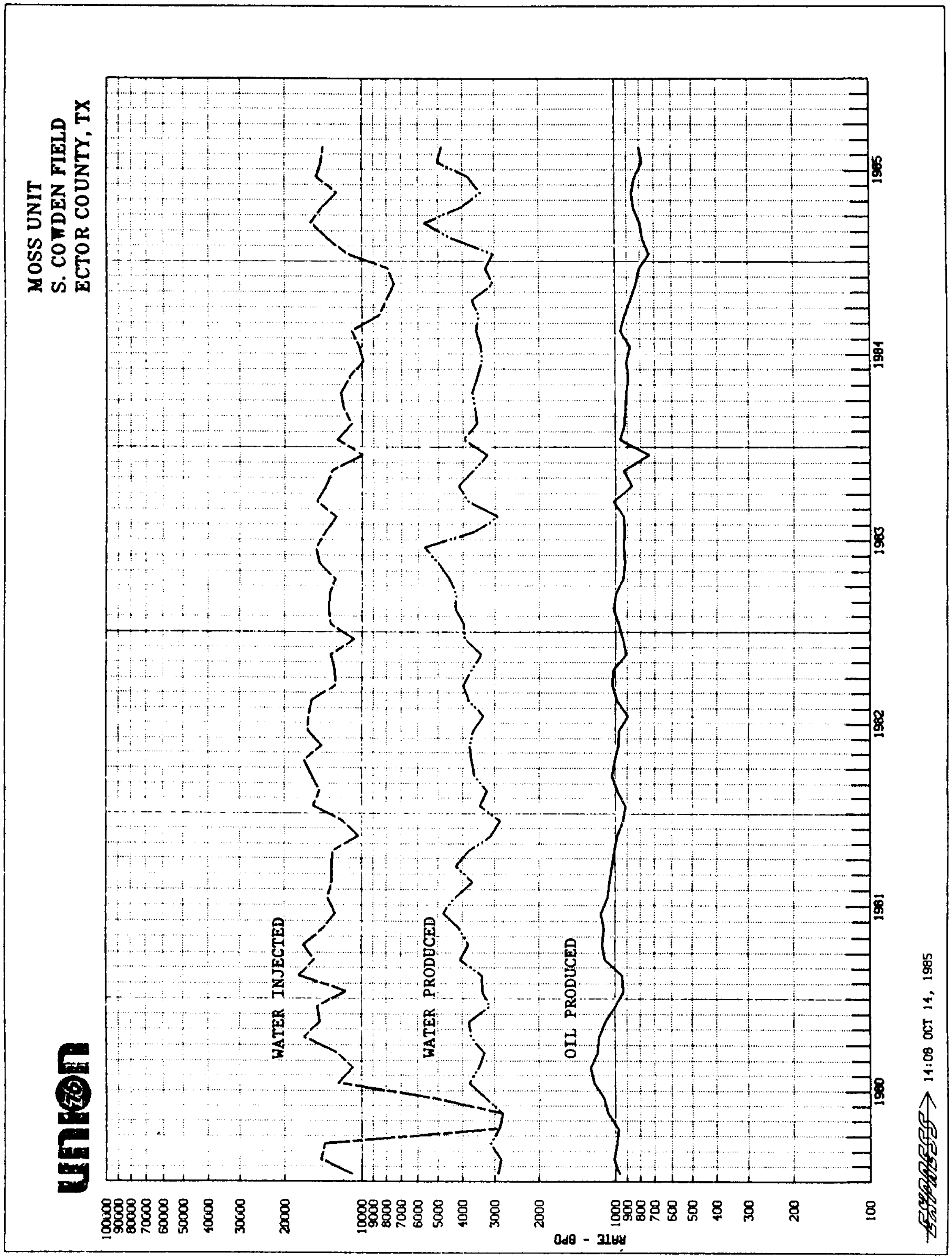

Figure 9 - Production and injection history