CASE STUDY OF PLUNGER LIFT INSTALLATIONS IN THE SAN JUAN BASIN

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Abstract

An analysis and economic evaluation of over 150 plunger installations in the San Juan Basin (SJB) has been made. The case study reviews performance and results of all installations, and clearly shows that plunger lift has significantly increased volumes and reserves. Best practices, screening criteria and design considerations are presented. Individual well results are presented in tabular form showing before and after rates. Economic analysis indicates plunger lift on these SJB wells is extremely attractive with average payout of installations in two months.

Introduction

The San Juan Basin consists of over 20,000 wells (mostly gas). The wells produce principally from four main Cretaceous reservoirs. These reservoirs are the Fruitland Coal, Pictured Cliffs, Mesaverde, and the Dakota. Most of the reservoirs are volumetric with minimal water and oil production. As these reservoirs have depleted and flow rates have dropped, the ability of a well to maintain the gas velocity necessary to keep the well free of liquids has decreased. Keeping these gas wells unloaded is a critical success factor for all operators in the San Juan Basin. Development is on 320 or 160 acre spacing units and locations are often remote and electricity is usually not available or expensive to install. These conditions make plunger lift an excellent artificial lift method for SJB wells.

This paper was initially an in-house lookback study to determine the profitability of Conoco's use of plunger lift in the San Juan Basin. The main objective was to determine if plunger lift had been economically successful and document the results. The secondary objective of the lookback was to determine if additional plunger lift systems should be installed and what screening criteria\best practices should be followed to evaluate subsequent plunger lift installations. Conclusions of this study and recommendations for proceeding forward with plunger lift installations follow. Over 150 installations are included in this study. Wells that had compression installed at or near the time plunger lift was installed have not been included in this study to eliminate volume increases due to compression rather than plunger lift. Also, only gas production increases have been included. This is because SJB oil/condensate production is normally very small(<5 BOPD) and difficult to track on a daily basis; however, any increases in oil production would improve the economics.

Discussion

Plunger lift might be best described as a more efficient form of gas lift. It differs in that it usually uses well shut-in pressure and a plunger or piston to lift fluids from the well bore and not an artificially imposed pressure. The greatest advantage over gas lift is that it limits fluid slippage or fallback. The plunger is essentially an efficient swab cup sweeping well bore fluids out of the tubing.

A detailed discussion of the fundamentals of plunger lift operation will not be discussed in this paper. However; plunger lift control on these installations is by programmable controllers. These controllers or "Smartboxes" are a critical success factor and part of the operating philosophy. Once the plunger lift system is installed and operating, it allows lease operators to spend less time at each well. The operators do not have to manually vent or unload wells. This can increase the number of wells operated per lease operator.

There are 154 plunger lift installations in the attached spreadsheet. There are 128 Dakota (DK) installations, 19 Mesaverde (MV) installations, and 7 Fruitland Coal (FC) installations. A typical 7,000' Dakota well will produce 100 MCFPD, 1 BCPD and 1 BWPD. A typical 4,500' Mesaverde well will produce about 250 MCFD, 1 BOPD and 1 BWPD.

The spreadsheet shows well, formation, pre-installation rate, post-installation rate, date installed, and payout days. The rates are monthly sales volume average before installation. The post-rate is monthly sales volume average 3-6 months after installation. Therefore, this rate is conservative, since immediately after installation, rates are almost always greater than the later monthly average. The payout calculation is based on a $5,000 installation cost, a gas price of $1.50/MCF and NRI of 0.76.

Economics

The spreadsheet shows that the average installation paid out in 66 days and also increased production by 66 MCFPD. Sixty wells paid out in less than 2 months. Forty four wells paid out in 2-4 months and seventeen wells paid out in 4-6 months. Sixteen wells had payouts longer than a year and fourteen wells showed no payout (no production increase or decrease). Although some of the wells did not show a payout, there was still some benefit to these installations. Eleven of these installations eliminated venting, either manual or by stop clocking. This reduces operator time, eliminates air emissions, and prevents waste. Nine of the "failure" installations did not improve production due to high line pressure.

In addition to this simple payout method of analysis, a total project economic evaluation was done. To do this, a question needed to be answered: What portion of these production increases are reserve additions and/or reserve acceleration? Since some of the wells were either shut-in or near the economic limit, production increases on these wells are obviously reserve additions. Production increases on economic wells also allow a well to produce longer before it reaches the economic limit, thus increasing reserves.

After much discussion, it was decided to do the analysis under the assumption that the production increases were 100% reserve acceleration. This methodology would give a bottom line conservative value of the plunger lift installations. Inputs and results of the analysis are shown below.

Investment:	$775,000
Net Present Value:	$8,234,000
Profitability Index	11.6
Internal ROR	>200%
Project life:	20 years
Discounted Payback	0.35 years
Operating Cost:	$100,000/year

These economics are very competitive with other investment opportunities and validate the simple payout calculations.

Conclusions-Operating Parameters

1. Lease Operator knowledge of plunger lift mechanics, trouble shooting, and optimization is critical to efficient plunger lift operation.

2. Programmable controllers can reduce the amount of time an operator spends at a location by automatically adjusting to changing line pressures and fluid volumes. This will reduce operating costs and help achieve higher well counts per operator while maintaining maximum production.

3. Gas venting, either manual or by stop-clocking, has greatly decreased on these SJB wells.

4. At current line pressures and rates, the majority of non compressed wells in the SJB do not have sufficient rate, to remain unloaded, even with 1.66" tubing.

5. The majority of plunger lift failures have been caused by mechanical problems with the wellhead or tubing string.

6. Small, i.e. 1.66" OD tubing, plungers break more frequently than larger plungers, and the tubing is difficult to unload following a shut-in due to its small volume per linear foot.

7. Field experience shows that plunger trips can be timed to prevent compressor underload or competition between low and high rate wells.

8. Field experience indicates plungers are an effective mechanical method for controlling paraffin deposition in tubing strings.

General Conclusions

1. Plunger lift systems are efficient in eliminating liquid loading problems on DK, MV, and FC SJB wells. The attached screening criteria can be used to minimize cost and increase overall success rate.

2. Lease operator training, buy in, and understanding are critical to the successful use of plunger lift systems.

3. Mechanical failures can be minimized by replacing tubing or wellheads.

4. Plunger lift can be an effective alternative to pumping units.

5. Plunger lift installations should be reviewed with lease operators and production technicians at least once a quarter to insure proper operation.

Plunger Lift Best Practices/Screening Criteria

1. Gather and document line pressure, well shut-in pressure and tubing pressures to evaluate an installation.

2. Determine current and past GLR.

3. Document and evaluate size and mechanical condition of the tubing. Perform the necessary wireline work. Run tubing drift and broach if necessary. Run test plug and test tubing before installation. If a tubing restriction/hole or casing leak is found or suspected, pull the well and correct the problem before installing the plunger system.*

4. Check for packers, surface line constraints or pressure control valves. Check wellhead for plunger clearance problems.

5. Screen well for current operating problems including manual venting and/or stop clocking.

6. Gather and analyze production history and establish an accurate daily sales baseline volume.

7. Run computer design program to determine operating parameters.

*The importance of the wireline work cannot be overemphasized. Holes in the tubing or restrictions will hinder plunger operation and most plunger lift installation failures can be attributed to mechanical problems.

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Well No.	Zone Form.	Pre-Inst Rate MCFD	Post-Inst Rate MCFD	Incremental Production MCFD	Date Installed	Payout Days
1	DK	38	425	387	7/21/95	11
2	DK		232	232	N/A	19
3	DK	86	295	209	6/22/95	21
4	DK	400	600	200	7/14/94	22
5	DK	42	233	191	5/20/94	23
6	DK	119	300	181	8/95	24
7	DK	95	275	180	11/1/93	24
8	DK		173	173	11/30/93	25
9	DK	80	238	158	6/3/94	28
10	DK	7	162	155	8/95	28
11	DK	100	251	151	5/94	29
12	DK	100	250	150	7/14/95	29
13	DK	88	225	137	7/20/95	32
14	DK	63	200	137	9/7/95	32
15	DK	42	165	123	6/28/95	36
16	DK	100	223	123	4/15/94	36
17	DK	28	147	119	5/23/94	37
18	DK		117	117	11/30/93	37
19	DK	30	144	114	9/95	38
20	DK	149	260	111	6/20/95	40
21	DK	131	242	111	7/7/95	40
22	DK	70	180	110	7/11/95	40
23	DK	40	147	107	8/95	41
24	DK	80	185	105	10/93	42
25	DK	37	140	103	7/25/95	43
26	DK	33	135	102	7/11/95	43
27	DK	51	150	99	8/3/95	44
28	DK	70	167	97	8/95	45
29	DK	104	200	96	6/15/95	46
30	DK	90	183	93	5/28/93	47
31	DK	30	123	93	4/23/93	47
32	DK	40	130	90	9/28/95	49
33	DK	53	142	89	5/22/95	49
34	DK	0	88	88	N/A	50
35	DK	20	105	85	6/94	52
36	DK	20	100	80	5/28/93	55
37	DK	59	138	79	8/8/95	56
38	DK		79	79	N/A	56
39	DK	39	117	78	11/93	56
40	DK	70	148	78	4/15/94	56
41	DK		78	78	1992?	56
42	DK	60	136	76	10/28/93	58
43	DK	35	110	75	8/15/95	58
44	DK	90	165	75	8/95	58
45	DK	150	225	75	6/95	58
46	DK	39	113	74	8/95	59
47	DK	12	86	74	3/93	59
48	DK	69	140	71	8/95	62
49	DK	80	147	67	5/93	65
50	DK	55	117	62	8/95	71
51	DK	90	150	60	4/26/93	73
52	DK	37	96	59	10/93	74
53	DK	106	164	58	7/12/95	76
54	DK	20	77	57	9/8/95	77
55	DK	100	155	55	5/28/93	80

Well No.	Zone Form.	Pre-inst Rate MCFD	Post-inst Rate MCFD	Incremental Production MCFD	Date Installed	Payout Days
56	DK		55	55	N/A	
57	DK	20	75	55	4/20/94	
58	DK	56	110	54	6/21/95	
59	DK	70	123	53	5/94	
60	DK	62	110	48	7/13/95	
61	DK	50	98	48	10/26/93	
62	DK	30	78	48	6/15/93	
63	DK	154	198	44	6/30/95	
64	DK	56	100	44	6/23/95	
65	DK	220	263	43	9/93	
66	DK	83	125	42	7/13/95	
67	DK	45	85	40	6/19/95	
68	DK	55	95	40	4/15/94	
69	DK	37	75	38	6/23/95	
70	DK	85	123	38	7/10/95	
71	DK	100	138	38	7/93	
72	DK	35	70	35	7/21/95	
73	DK	30	65	35	5/28/93	
74	DK	75	110	35	3/29/93	
75	DK	20	54	34	9/93	
76	DK	100	132	32	10/27/93	
77	DK	13	45	32	11/93	
78	DK	19	50	31	8/4/95	
79	DK	100	131	31	5/28/93	
80	DK	50	81	31	11/4/93	
81	DK	30	61	31	10/26/93	
82	DK	20	50	30	7/19/93	
83	DK	215	245	30	2/95	
84	DK	59	87	28	8/1/95	
85	DK	TSI	27	27	2/22/93	
86	DK	50	75	25	3/93	
87	DK	27	52	25	10/93	
88	DK	85	110	25	10/27/93	
89	DK	18	40	22	7/19/95	
90	DK	70	92	22	10/22/93	
91	DK	100	122	22	4/29/94	
92	DK	86	106	20	7/94	
93	DK	11	30	19	9/19/95	
94	DK	20	37	17	10/93	
95	DK	20	37	17	6/94	
96	DK	39	55	16	10/93	
97	DK	6	20	14	8/95	
98	DK	40	54	14	10/93	
99	DK	7	20	13	8/95	
100	DK	48	61	13	10/93	
101	DK	17	29	12	5/94	
102	DK	134	145	11	10/93	
103	DK	?	10	10	1991	
104	DK	8	18	10	4/94	
105	DK	45	55	10	4/94	
106	DK	60	70	10	5/29/93	
107	DK	75	84	9	1991	
108	DK	120	128	8	6/22/94	
109	DK	115	120	5	8/2/95	
110	DK	90	94	4	10/25/93	

Well No.	Zone Form.	Pre-inst Rate MCFD	Post-inst Rate MCFD	Incremental Production MCFD	Date Installed	Payout Days
111	DK	175	178	3	7/94	1462
112	DK	25	27	2	4/94	2193
113	DK	40	42	2	4/15/94	2193
114	DK	50	51	1	5/93	4386
115	DK	120	120	0	3/93	ERR
116	DK	35	34	-1	5/94	-4386
117	DK	74	73	-1	10/93	-4386
118	DK	5	3	-2	4/94	-2193
119	DK	3	0	-3	5/94	-1462
120	DK	40	32	-8	5/94	-548
121	DK	33	20	-13	7/24/95	-337
122	DK	20	0	-20	11/2/93	-219
123	DK	100	77	-23	2/14/94	-191
124	DK	119	87	-32	8/95	-137
125	DK	150	114	-36	9/93	-122
126	DK	120	83	-37	7/20/93	-119
127	DK	200	105	-95	8/94	-46
128	DK	200	104	-96	9/93	-46
DK Totals		8,236	15,646	7,410	128	76
1	FC	155	474	319	12/2/92	14
2	FC	75	273	198	6/94	22
3	FC	212	330	118	8/95	37
4	FC		58	58	N/A	76
5	FC	32	50	18	7/1/95	244
6	FC	81	85	4	7/94	1096
7	FC	65	65	0	8/95	ERR
FC Totals		620	1,335	715	7	43
1	MV	0	320	320	8/95	14
2	MV	200	430	230	7/94	19
3	MV	137	350	213	6/94	21
4	MV	175	375	200	4/93	22
5	MV	250	430	180	7/12/94	24
6	MV	75	250	175	3/28/94	25
7	MV	295	450	155	4/5/95	28
8	MV	107	225	118	3/30/95	37
9	MV	80	178	98	10/29/93	45
10	MV	66	145	79	7/17/95	56
11	MV	20	80	60	9/25/95	73
12	MV	170	228	58	6/28/95	76
13	MV	0	55	55	8/95	80
14	MV	190	225	35	8/95	125
15	MV	300	335	35	8/95	125
16	MV	40	70	30	8/95	148
17	MV	21	50	29	7/22/95	151
18	MV	200	224	24	5/94	183
19	MV	60	70	10	5/93	439
MV Totals		2,386	4,490	2,104	19	40
Totals		11,242	21,471	10,229	154	66

Payout calculation based on $5,000/well and $1.50/MCF gas price.