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Field Trials of Newly Developed Positive Displacement Submersible Pump

Rob Beard
Beard Oil
PO Box 490
Dewey OK, 74029

Leland Traylor
PSI Pumps
11510 Ranchitos Ave NE
Albuquerque NM 87122

Disclaimer

Abstract

The purpose of this grant was to evaluate under real world conditions the performance of a new type of downhole pump, the hydraulically driven submersible diaphragm pump. This pump is supplied by Pumping Solutions Incorporated, Albuquerque NM. The original scope of the project was to install 10 submersible pumps, and compare that to 10 similar installations of rod pumps.

As an operator, the system as tested was not ready for prime time, but has shown the ability to reduce costs, and increase production, if run times can be improved. The PSI group did improve the product and offered excellent service. The latest design appears to be much better, but more test data is needed to show short run life is not a problem. PSI and Beard Oil intend to continue testing the pump with non-government funding. The testing to date did not uncover any fundamental problems that would preclude the widespread use of this pump, and as an operator, I believe that with further improvement and testing, the pump can have a significant impact on stripper well costs. On the positive side, the pump was easy to run, was more power efficient then a rod pump, and is the only submersible that could handle the large quantities of solids typical of the production environment found at the Weber field and in CMB production. The product shows much promise for the future, and with continued design and testing, this type of submersible pump has the potential to become the standard of the industry.

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Introduction

The purpose of this grant was to evaluate under real world conditions the performance of a new type of downhole pump, the hydraulically driven submersible diaphragm pump and compare that performance to traditional rod pumps. Twenty submersible pumps supplied by Pumping Solutions Incorporated, Albuquerque NM have been installed in 6 different wells to date. The original scope of the project was to install 10 submersible pumps, and compare that to 10 similar installations of rod pumps. Frequent failure of the submersible pumps have required that the pumps be replaced to maintain production and to date have not allowed for a meaningful cost comparison between the two systems over the long term.

Meaningful cost comparisons can be made for several cost items, including power, initial costs, daily maintenance costs, and production increases. What cannot be calculated, because of short run times, are the amortized costs of ownership, which would include pull and run, pump rebuild and cable costs, but these will be estimated making some assumptions on run times. These cost figures are included in this report.

Executive Summary

As of the date of this report, 20 diaphragm pumps have been installed into 6 different wells, in Oklahoma, New Mexico and Wyoming. Results from some of the 20 installations are included as part of the test data, but were not paid for as part of this project. When the project started in 2001, the diaphragm pumps being offered by PSI were very experimental, and as such, many problems were encountered. Along the way (and as a direct result of this project) PSI was able to improve the design and gained valuable data from these field tests. With out the assistance of the DOE, it is doubtful that Beard Oil would have installed more than a couple of the early, short lived units.

The primary field where the test was conducted was the Weber field, which is one of the oldest oil fields in Oklahoma. It is a nearly depleted waterflood, producing on average 1 BOPD, with 90 BWPD. The waters are extremely corrosive due to the high oxygen content, and the presence of H_2S and CO_2. Wells in this area are notorious for their corrosive properties. The harsh conditions may well have accelerated testing of the pump, and probably led to shorter runs than would be experienced in other areas. The wells tested were 1300' and produced from a shot perforated 4.5" API casing. Other tests were conducted in the Red Mountain field in Western New Mexico, the San Juan Basin in New Mexico, and Teapot Dome in Wyoming. The San Juan Basin wells were coal bed methane wells, the rest were conventional Oil Wells.

As an operator, the system as tested was not ready for prime time, but the product was steadily improved over the length of the project. The latest design appears to be much better, but more test data is needed to show short run life is not a problem. This product should continue to be developed; the testing did not uncover any fundamental problems that would preclude it's widespread use. On the positive side, the pump was easy to run, was more power efficient then a rod pump, and is the only submersible that could handle the large quantities of solids typical of CBM production. The product shows much promise for the future, and with continued design and testing, this type of submersible pump has the potential to become the standard of the industry.

Experimental and Operating Data

The primary field where the test was conducted was the Weber field, which is one of the oldest oil fields in Oklahoma. It is a nearly depleted waterflood, producing on average 1 BOPD, with 90 BWPD. The waters are extremely corrosive due to the high oxygen content, and the presence of H_2S and CO_2. Wells in this area are notorious for their corrosive properties. The harsh conditions may well have accelerated testing of the pump, and probably led to shorter runs than would be experienced in other areas. The wells tested were 1300' and produced from a shot perforated 4.5" API casing. Other tests were conducted in the Red Mountain field in Western New Mexico, the San Juan Basin in New Mexico, and Teapot Dome in Wyoming. The San Juan Basin wells were coal bed methane wells, the rest were conventional Oil Wells.

The table below is in chronological order, depicting the installation, the run time, the cause of failure, and the corrective action. The discussion following will show how the pump has improved over the life of the grant and how the testing uncovered design weaknesses that PSI needed to correct, and how those were ultimately corrected.

Installation Location	Date	Run Time (days)	Cause of failure	Solution
Tiger #2, San Juan	10/9/01	1	Mechanical cable damage	Reinstall with new cable
RMOTC	11/6/01	95	Frozen Output due to low surface temp	Operator Procedure
Weber #1	11/29/01	8	Electrical- due to splice failure	Reinstall with new splice
Weber #1 reinstall	12/12/01	45	Leak in hydraulic system	Crimp procedure and design
Red Mountain #12	12/15/01	710 days- still good	None- but not on continuous run	
Red Mountain #14	1/9/02	679 days- still good	None- but not on continuous run	
Tiger #2 Reinstall	1/14/02	1	Cable pinched on install	More robust cable
Weber #1	2/6/02	14	Leak in sensor diaphragm	Better QA proceedure
Weber #1	2/28/02	1	Foreign material in hydraulic system	Better filtration and QA
Golden Bear #4 San Juan	3/14/02	90	Electrical due to surface switchbox	Operator Problem
Tiger #2 Reinstall	3/22/02	14	Electrical Overload	Larger Generator
Weber #1	4/5/02	21	Cow ate cable	Surface fence added
Weber #1	5/1/02	60	Outcheck backed out	Locking mechanism added
Tiger #2 Reinstall	5/23/02	4	Operator shut in	Operator

			pump	procedure
Weber #1	7/15/02	4	Cable damage at clamp	Change clamping procedure
Weber #1	9/25/02	0	Check valve not installed	QA procedures change
Weber #1	10/2/02	45	Corrosion	New PD Pump design
Weber #1	11/11/02	21	Diaphragm leak	New Diaphragms
RMOTC	5/15/03	61	Diaphragm lead	New Diaphragms
RMOTC	5/10/03	127	Not known	

Data Reduction

Statistics
Raw data average run time- 105 days
Removing data points less than 4 days- 162 days

Results and Discussion

The average run time for a rod pump in the same field over the same period of time was 270 days- significantly longer than the diaphragm pump. Many of the failures are explainable and not due to pump design, but on average, the pump did not achieve sufficient run time to be considered a replacement for the rod pump in this situation. In the CBM wells and in oil wells, the pump did achieve a small but significant increase in gas production, about 20%, but it did not last long enough to determine if the increase is sustainable. It is interesting to note that the replacement pumps in both the Tiger #2 and the Golden Bear had much worse performance than the diaphragm pump, indicating that high solids content found in these wells make short run times the norm.

The PSI diaphragm pump design has improved significantly over the life of this program, as a direct result of this testing. The following improvements/changes were made to address problems uncovered during the test program:

More robust cable.- The project started out using low cost water well type PVC cable, this did not perform in the mechanical environment, and had gas saturation problems in CBM wells. The project switched to a Polyethylene jacket cable that performed much better.

Better Splice- The project started out using a water well type splice that is a thermoshrink sleeve with a resin filler that is designed to melt and fuse with the insulation. This type of splice is not compatible with the oil well environment, and failed several times during the course of the project. A Teflon tape splice was used later on and did not fail in several subsequent installations.

QA procedures- Many of the later failures were due to QA problems that arose when the pumps went from being hand made in Albuquerque to a factory in Oklahoma. The transition uncovered several problems that were subsequently corrected.

Corrosion- This was the most serious problem uncovered and could not be solved simply. It required the manufacturer to come up with an all stainless steel pump cover to prevent the problem.

Non-Problems- The pump did not suffer any unexplained motor or hydraulic system failures, and diaphragms removed from the tests appeared to be as good as new. Sand clogging was not a problem in any test, the pump seemed to be tolerant of an amazing amount of sand. No wear was ever detected on any of the parts.

Diaphragms- Late in the test program, diaphragm problems emerged as a dominate failure mode. PSI has in process completely new diaphragm materials being evaluated for use at this time. Diaphragm life and design are the key factors for a long lived pump, and improvements should have a significant positive impact on run life.

Cost Data

Real cost data for any pumping system is very difficult to obtain, and can be biased up or down depending on the assumptions made. For example, determining the real cost of a rod pump installation can vary wildly depending on if new or used equipment is assumed. To better compare costs, they are broken down into three categories, initial equipment costs, operating costs and production costs. Initial equipment includes the pumping unit, downhole equipment, rod string, tubing string and surface equipment. Operating costs include pull and run, electricity, pumper labor, parts for surface repair and pump rebuild costs. Production costs include increase or decreases in production due to pump performance and lost production due to downtime. Service life is the critical factor in determining economics, and because service life has not been established for the PSI technology, assumptions have been made to generate meaningful cost comparisons. The equipment costs for these cases are based on experience and PSI estimated net costs.

Initial Equipment Costs Rod Pump

Cost Element	Unit Cost	Total Cost
Surface Unit	7500	7500
Rod String	.75/ft	1012
Tubing String	2.00/ft	2700
Surface Equipment	500	500
Downhole Pump	2500	2500
Installation	2000	2000
Total Cost		16212

Initial Equipment Costs for PSI Pump

Cost Element	Unit Cost	Total Cost
Pumping Unit	5000	5000
Tubing	2.00/ft	2700
Cable	1.00/ft	1350
Surface Equipment	500	500
Installation	1000	1000
Total		10100

Operating Cost for Rod Pump per year

Cost Element	Unit Cost	Total Cost
Pull & Run	1300	1300
Electric	216/mo	2592
Replacement Rods & tubing	2.75/ft	928
Rebuild Downhole	1200	1200
Pumper labor	30/mo	360
Routine Maintenance	75/mo	900
Total		7280

Assumptions:
0.06/kwh
5kw motor load
string replaced every 4 years
1 pull and run/year

Operating Costs for PSI Pump per year

Cost Element	Unit Cost	Total Cost
Pull and Run	1300	1300
Electric	86.40/mo	1037
Replacement Tubing	2.00/ft	338
Pump rebuild	1300	1300
Pumper Labor	30/mo	360
Routine Maintenance	25/mo	300
Total		4635

Assumptions:
0.06/kwh
2kw motor load
string replaced every 8 years
1 pull and run/year

Production Cost for Rod Pump per year

Cost Element	Unit Cost	Total Cost
Lost Production	30/day	300
Total		300

Assumptions:
Down 10 days/year

Production Cost for PSI Pump per year

Cost Element	Unit Cost	Total Cost
Lost Production	30/day	300
Production Enhancement	3/day	-365
Total		-65

Assumptions:
Down 10 days/year
Production increases 10% due to better drawdown

Assuming straight line depreciation with no interest for 10 years, the initial costs average $1621/year for the Rod pump and $1010/year for the submersible pump tested. The aggregate yearly operating costs are $ 7580 for the rod pump and $4570 for the submersible pump. The total yearly cost for each is $9201/year for the rod pump and $5580 for the submersible pump. This assumes that the submersible pump can last at least 1 year in the environment, which has yet to be proven. With 2 pull and runs/year the submersible pump has little economic advantage over the rod pump. With the risk of pump failure high for the unproven submersible pump, the manufacturer would need to give a guarantee of 1 year run time, with a rebate for proportional pull and run costs to get my business. Once run times are established, this would not be required, but is very important for this type of project because of the risk of pump failure.

The analysis is relatively insensitive to initial costs, but is very sensitive to frequency of failure and rebuild costs. This means that PSI must improve pump life, and maintain a low cost of pump rebuild to be competitive.

Conclusion

As an operator, the system as tested was not ready for prime time. The PSI group did improve the product and offered excellent service. The latest design appears to be much better, but more test data is needed to show short run life is not a problem. This product should continue to be developed; the testing did not uncover any fundamental problems that would preclude it’s widespread use. On the positive side, the pump was easy to run, was more power efficient then a rod pump, and is the only submersible that could handle the large quantities of solids typical of CBM production. The product shows much promise for the future, and with continued design and testing, this type of submersible pump has the potential to become the standard of the industry.