PLUNGER LIFT BY SIDE STRING INJECTION

A METHOD OF PRODUCING WELLS BY PLUNGER LIFT IN WELLS WITH LOW BOTTOM HOLE PRESSURE BY INCORPORATING SUPPLEMENTAL SURFACE INJECTION VIA SIDE STRING

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ABSTRACT

A project was undertaken to utilize plunger lift in wells with abnormally low bottom hole pressures. This was accomplished through the use of coiled tubing for side-string injection (see schematic). This application has a wide range of applicability for high water cut low-pressure reservoirs.

INTRODUCTION

"Problem" wells exist in many different circumstances throughout the oil field. The "problems" in this particular instance consist of the following:

1. Low bottom hole pressure
2. Deviated hole
3. Corrosion
4. Abnormal maintenance cost associated with these problems
5. Rod pump gas locking associated with an over-abundance of gas in relation to the amount of fluids being produced
6. Paraffin build-up
7. Iron Sulfide

Wells that exhibit these characteristics normally exhibit high lifting costs due to a high frequency of rod failures. Along with failures, preventive measures such as hot oiling or chemical treatments also contribute to higher lifting costs. Plunger lift or gas lifting is a logical solution for decreasing lifting costs. However, conventional gas lift is not practical because increased back-pressure on the formation will prevent adequate inflow to make the wells economical. Conventional plunger lift is not a feasible alternative because the BHP is too low to provide necessary lift. Side string injection seemed to be a viable solution for solving this artificial lift problem.

TEST WELL

In order to test the proposed artificial lift system, a well was chosen from the Indian Basin field in Eddy County, New Mexico. The following is a list of generalized data that is representative of the test well, and other wells in the area similar to it:

SBHP:	300 PSI
TD:	8200 ft
PBTD	8100 ft
Gas Production:	500 MCFD
Oil Production:	3 BOPD
Water Production:	85 BPD
Tubing Size:	2 7/8 inches
Casing Size:	7 inch 23 lb/ft
Perforation Interval:	300 ft

METHODOLOGY

In order to properly test and apply this technology, a background of fluid level and well test data was gathered. Using this data, it was determined how far below the perforations the standing valve would have to be, in order to produce adequate fluid volumes per trip. The limiting factor in this system is the fact the fluid level in the well bore will be equal *to* the fluid level in the tubing between cycles. Thus, and therefore, the higher the fluid level, the more fluid produced on each trip that the plunger makes. Consequentially, the lower the fluid level, the less fluid produced on each plunger trip. After the standing valve setting depth was determined, it was possible to utilize the known fluid level data along with the known surface pressure of injection gas, and calculate the volume of water that could be produced in a given time interval.

RESULTS

Well tests indicate that the well is producing the same amount of fluid on gas assisted plunger lift as it was on rod pump. The economic benefits are realized in reduced operating costs due to rod pump failures and treating costs, as well as the salvage values of the rod pumping equipment. Electrical costs are also virtually eliminated, and only a recompression fee is assessed to the well. The higher rod pumping equipment can be utilized in other areas of the field thus creating a greater return on the original capital investment.