A Graphical Study of Pumping Wells

By BENNIE L. FRANKS
Sun Oil Company

ABSTRACT

Better design, study of operations and planned maintenance of subsurface equipment can often result in reduced lifting cost per barrel of oil. A suggested graphical history of pumping operations will be presented which acts as a guide to determine lifting cost per month or year. Simple graphical records help to readily illustrate problem wells and are also good guides for determining remedial action when necessary. Field cases using the graphical form and results of remedial work will be presented.

Normal pulling cost and pump maintenance at various depths will be discussed to emphasize the large sums of money that are being spent and the need of monthly systematic well records to determine if operational problems exist.

INTRODUCTION

Pumping cost per barrel of oil has accelerated rapidly with the reduction in income caused by lower producing day schedules and the costs of higher pulling, pump repairs and steel products. Therefore, oil companies, major as well as independents, have been forced to re-evaluate costs in all phases of their operations; one such main area is subsurface pumping equipment. This area often has been neglected due to the development of new wells demanding the bulk of time of the field personnel. In many cases, lifting cost increases are due to declines in production and should be periodically checked. As deeper wells are placed on pump and larger volumes of fluids are lifted, many problems develop which previously did not exist.

Better design, study of operations and planned maintenance of subsurface equipment can often result in reduced lifting cost per barrel of oil. A suggested graphical history of pumping operations will be presented which acts as a guide to determine lifting cost per month or year. Simple graphical records help to readily illustrate problem wells and are also good guides for determining remedial action when necessary. Field cases using the graphical form and results of remedial work will be presented.

Normal pulling costs and pump maintenance at various depths will be discussed to emphasize the large sums of money that are being spent and the need of monthly systematic well records to determine if operational problems exist.

The graphical analysis is a complete record of pumping history, with costs, and can be redesigned to suit the needs of your company. They can be kept by either pumpers or other field personnel. It can become a quick and easy reference to justify pulling jobs or other remedial work.

GRAPHIC STUDY

A graphic study begins with plotting failures on a month versus depth basis. The graph considered is for a 12 month period from which annual costs can be derived. Various symbols are used to classify subsurface failures, such as a circle for sucker rod failure, triangle for tubing failures, and an inscribed circle in a square for pump failures. To further explain causes for these failures, each job is classified as the result of corrosion, paraffin, scale, mechanical defects or wearing.

Sucker rod failures are broken down into four classifications:

1. body breaks,
2. pin breaks,
3. coupling breaks, and
4. unscrewed rods.

Body Breaks

If, during a year's operation one body break occurs it would be hard to condemn a string of rods. However, if two or more rod parts develop, then some research should be done. When a string which has given normal performance has several rod breaks, it becomes economically feasible to make a change in your present operating practice. Factors which cause rod breaks are fluid environment, rod load, range load and rod fatigue.

Fluid environment often influences the service life of pumping equipment in relation to the quantity of salt, hydrogen sulfide or carbon dioxide water handled. Chemical inhibition has been satisfactory in alleviating these corrosion failures. If corrosion is only slight or mild, then consideration should be given to using regular equipment with chemical treatment, or to using more corrosion resistant rod strings without treatment. In the more corrosive areas, not only must chemical inhibition be incorporated but higher alloy rods should be placed into service if economically feasible.

Rod loads which include rod weight and pump load can definitely be a factor causing rod body breaks. Many times a well has been equipped with an efficient designed rod string; later, fluid capacity is increased by water encroachment or well stimulation without rod string stresses being rechecked. As a general rule, rod manufacturers set 30,000 psi dynamic load as the maximum stress of sucker rods. Wells have been pumped with higher rod stresses without failures; conversely, other rod strings have parted at 13,000 psi, indicating they have lost some of the metallurgical properties during service.

As a rule of thumb, 26,000 psi dynamic load, where practical, is a safe design factor for rod strings. Many times a 1-1/4 inch pump is pulled and replaced with a 1-1/2 inch pump without much consideration for the added rod stress. In this change of pump sizes, the static fluid load has been increased 67 per cent.

Range loads have caused many rod breaks without the operators realizing this fact.

Range load is described as the difference between maximum dynamic load and minimum dynamic load. It is usually expressed in per cent range load which is range load divided by minimum load. Rod manufacturers recommend that range loads should not exceed 60 per cent of minimum load. Factors causing high range loads are fluid pounds, pump friction, scale, sand, paraffin, buckling of tubing, crooked hole and synchronous pumping speeds.

Range loads can be reduced either by cycling wells to reduce fluid pounds or positioning fluid pounds in the top one-quarter of the down stroke. Increasing tolerances of pump fits is helpful. Running stroke through pumps where scale has become a problem is recommended. Paraffin can often be reduced by chemical treatment, heat, scraping or installation of plastic coated tubing. Original design as to non-synchronous pumping speeds should be considered and followed. This is especailly true in any well below 3500 feet deep at 15 SPM or greater. At deeper depths, the synchronous points at even lower SPM's should be calculated since the four order card develops at 8 SPM for an 8000 foot well.

Tapered rod strings are another method of reducing the rod load and range load. Also tapered strings reduce the peak polish rod horsepower, thereby saving on energy consumption.

Rod string wear can be reduced with the aid of tubing anchors and also by increasing rod sizes for given tubing sizes. Rod guides have an application if the wear is the results of crooked hole.

Pin Breaks

Pin breaks are generally the result of improper make up. If, after snapping-up rod strings, any foreign material is between the face of coupling and rod, the pin is susceptible to failure. Such breaks are common in wells below 6000 feet which are normally subjected to the higher stresses. Also, the men that install such strings usually become tired and less efficient and fail to snap-up strings sufficiently.

Pin breaks in newly installed strings are usually the result of a failure to clean the boxes and pins after storage in warehouse yards. To properly clean rods on a 6000 foot job adds approximately $30 and will result in a large saving if a pin break can be prevented. There is little that can be done for damaged pins or pins that have been corroded other than using a chemical inhibitor in the coupling to retard further deterioration.

Rod Coupling Failures

These failures, in our experience, have been limited normally to 3/4 inch and 7/8 inch slim hole couplings. Normally, the major cause of coupling failures is the use of hammers. Coupling failures have been laboratory analyzed and it has been found that many initial breaks radiate from hammer marks.

Another common cause of coupling failure is internal corrosion of the coupling resulting in failures at the point of the first thread of the bottom pin. This can be eliminated by changing couplings in the area of trouble. Many operators have minimized this condition by applying a chemical inhibitor in the couplings when a pulling job is in process. In other cases of deep pumping wells, some operators have changed from slim hole couplings to standard couplings and installed 2-1/2 inch in the area of 7/8 inch rods so that fishing operations can be performed.

Unscrewed Rods

Normally this is a result of improper make-up and can be eliminated with closer supervision. Unclean boxes and pins can give the impression of satisfactory make-up and then back out as pumping is commenced, due to tubing buckling during a pumping cycle.

A rod string is the connection from the power source to the pump. It requires common sense and a degree of workmanship while handling it. Rod strings properly sized, used, and cared for can result in savings to your company. If improperly placed in operation, the rods can cause problems and increase lifting cost in a short period of time.

TUBING FAILURES

Tubing failures are classified into four categories:

1. body leak,
2. coupling leak,
3. parted, and
4. pulled for pump

Tubing Body Leaks

This is the most common problem in tubing leaks. Body leaks result from corrosion or worn portions of the body of a joint and can possibly be caused by plugging of the tubing or flowing with paraffin.

The most common cause is rod wear on the internal portion of the tubing. The first approach is a tubing anchor if the wear is on the bottom of the string. Rod guides plus rotation of tubing tend to minimize local wear. Respacing of couplings periodically along with pumping at the desired speeds to reduce harmonics in the pumping string are helpful. Using larger size rods in a given size tubing also tends to reduce internal wear. If the rod wear is localized in the immediate area above the pump, either larger sucker rods, or in some cases polish rods, should be used at the part of the string.

Corrosion in the tubing often can be retarded economically with chemical inhibition, though in some cases plastic coated tubing is desirable.

Tubing Coupling Leaks

Tubing coupling leaks can result from improper make-up but normally are the result of continual tubing travel over a long period of time. A tubing anchor can eliminate tubing travel and can help eliminate tubing leaks if the threads are not already fluid cut to the point of a washout condition. Using the smallest bore pump will reduce tubing travel and help relieve thread wear. Pumping at synchronous speeds and pounding fluid will accelerate tubing leaks.

Parted Tubing

Normally this is the result of corrosion or continual pounding of fluid. This is an uncommon occurrence and normally does not present a major problem. Treatments for corrosion are often successful in stopping tubing parts. Tubing anchors help eliminate parts and are always beneficial in deep well pumping. Using the smallest possible pump, the longest stroke and non-synchronous speeds often will reduce tubing parts.

Pulled for Pump

It is necessary to pull tubing when the pump or rod string parts and cannot be fished. This is common where paraffin or scale accumulation occurs and prevents normal fishing jobs. Most of the main problems of tubing failures can be eliminated with tubing anchors. Calipering and pressure testing can eliminate many potential tubing problems. Tubing testing is definitely useful on old strings which have been in service and show signs of rod wear or hydrogen sulfide embrittlement.

PUMP FAILURES

Pump failures are classified as follows:

1. pulled and replaced,
2. pulled and repaired,
3. stuck, and
4. pulled only

Pulled and Replaced

This class represents pumps replaced that are not repairable or replaced when an available pump was on hand for exchange. A description of the pump pulled will be made to determine whether the failure was due to corrosion, scale, wear or a mechanical defect.

Pulled and Repaired

Such a pump classification is one which has been pulled and repaired and placed back on production. Identification as to the cause of pump failure will be made as in the case of the preceding classification.

Stuck Pump

This represents wells with plunger stuck either with scale, sand, or in some cases paraffin. Classification as to the specific cause should be made.

Pulled Only

These are wells in which pulling or unseating of pumps is the only work performed. This is a common occurrence after placing a well on pump when scale or paraffin accumulations are present.

There are many different types and combinations of pumps available that could be discussed in this report. However, there are definite basic principals that are followed by most operators. Any type pump that has performed satisfactorily for six to twelve months is not a real problem. When a pump failure occurs in less than four months service, some other type of pump should be considered. One operator in a 2600 foot field had 12 pump service jobs on one well in seven months, totaling $1,625 for pulling unit, pump repairs, and fishing jobs. A change was made to a metal-to-metal insert pump and the well produced for five months without a pulling job.

Cup type pumps have given good service and are good when the total fluid handled is high. However, short life has been experienced when pounding fluid conditions exist. If cup type pumps are used, time cycling to prevent continual fluid pounds will usually increase the service life.

Stroke-through type pumps have been very effective in producing fluids that tend to gyp-up standard insert pumps. However, stroke-through pumps are limited as to the quantity of fluid handled since the maximum size in 2 inch tubing is 1-1/4 inch. If a high capacity is not necessary, such a selection should perform properly.

There are many good quality pumps that have done a fine job in handling corrosive fluids. However, such pumps should be used only where necessary, due to the higher pump cost.

To point out such an example, a standard metal-to-metal pump was in service 19 months in a 6700 foot well and when pulled was corroded to the point of replacement. During the service life of the pump, it had handled 37,000 barrels of fluid and after studying the records, it was not replaced with a corrosion resistant pump because the extra cost for that type pump would not be justified.

In new fields where little information is known as to the pumping characteristics, purchasing a standard pump is the practical way to approach the problem. Inspection when the pump is pulled can guide your decision on future pump selections.

The best possible way to extend subsurface pump life is by utilizing the longest length stroke and slowest non-synchronous pumping speed to obtain the necessary production. Extended service life of equipment has occurred by chemically slugging wells prior to shut down day, where treatments for corrosion or scale are being followed. In deep well pumping, insert pumps seem to perform longer with a rod guide above the pump. They should be equipped with a larger pull rod when high volumes of fluid are being handled.

All subsurface pumps, when broken down in the pump shop, should be inspected by field personnel. After determining cause of failure, make up a pump after evaluating all the facts. When considering normal expenditures of $350 for a 6500 foot well, correct replacement of pumps is imperative.

FURTHER EVALUATION OF SUBSURFACE FAILURES

To further evaluate subsurface failures, all jobs are classified as to the apparent cause, such as C-Corrosion, P-Paraffin, S-Scale, W-Worn and M-Mechanical.

C-Corrosion

If failures occur consistently in rods, tubing or pumps as a result of corrosion, either the chemical treatment is inadequate and should be changed, or treatment should be initiated. To further evaluate, consideration should be given to the length of service, quantity of fluid handled, etc. This might help to obtain justification for considering chemical treatment. Many times, however, fatigue is a major factor in equipment failure and has been misclassified as corrosion.

P-Paraffin

Often the high cost of paraffin removal will be shown if each operation is classified. Paraffin deposition can be handled satisfactorily in some cases with chemicals, mechanical scrapers, hot oiling, passing of scrapers, and plastic coated tubing. All these expenditures should be backed up with well history to evaluate the necessity of such cost and, later, to justify the expenditures. Paraffin often causes continual unbalanced pumping conditions, thereby consuming additional energy.

S-Scale

Scale deposition has been combatted by complex phosphates which keep these deposits from forming. Stroke-through pumps have helped eliminate premature failures of subsurface pumps. Both have their places but must be proved economically feasible to use. Many times, periodical acid dump jobs will do a satisfactory jot at a nominal cost.

W-Worn

This refers to equipment that has been fluid cut or has abraded areas. If such a condition should exist in subsurface pumps, better pump selection is necessary if short performance has occurred. Tubing and rod abrasion has been covered earlier in this paper.

Well equipment is classifed as:

1. tubing size, date installed and condition,
2. rod size or sizes, date installed and condition,
3. dump depth and bottom of the hole in feet.

With the above data and length stroke, strokes per minute, and pump size complete, pump capacities can be calculated. All volumetric calculations should include rod stretch, tubing travel and impulse factor. From this data, polish rod load, correct counterbalance, peak torque and prime mover sizes can be determined.

From the graphical history of pumping wells, we can get a good picture of the effectiveness of the equipment. To further evaluate the economics of the particular installation, additional information is necessary.

ADDITIONAL INFORMATION

Pulling Records

To correspond with the graphical identification, the pulling unit cost is shown for each job along with a cost for equipment replaced or repaired. This material cost may be an estimate in the case of rods and tubing wince this equipment is often in stock and has no set value assigned. Pump repair charges can usually be obtained exactly from pump shop tickets. The total, therefore, represents the cost of performing these pulling jobs.

Chemical Records

If chemical treatments are being used for paraffin, corrosion or scale, important data such as date started, type of chemical, and quantity per quarter or six months should be shown. Also a cost to maintain these treatments should be shown.

Special Services

This represents operations not included in other sections such as hot oiling charge, paraffin scraping with pulling units, caliper surveys, rod inspections and pressure testing of tubing. Also included is special equipment installed for better pumping operations. An accurate description of work performed and cost should be included.

All costs of maintaining subsurface equipment have been discussed and, if kept satisfactorily, will help determine if a problem exists and what the cost is for that problem.

Additional information can be kept on this report if it is felt that it is necessary, such as cost per month for energy, whether electrical or butane, and also monthly maintenance cost of electrical prime movers or internal combustion engines. In the case of gas engines, an approximate monthly figure can be arrived at by determining the cost of oil, water, anti-freeze, spark plug, filter replacements, magneto repairs, etc. Any motor or electrical repair charges may be obtained if a notation is made on the report.

To obtain a yearly cost, simply total each section: pulling record, chemical compound record, special services. These totals represent subsurface cost per year. To further study lifting cost, total the energy cost and prime mover cost — these two represent surface cost. Surface cost and subsurface cost represent yearly expenditures to keep this particular well in operation. By totaling barrels of oil and water produced during the year, a cost per barrel basis can be made. Many times field personnel will not be in a position to complete this form. However, they can furnish all pertinent data recorded in the proper sections. If a well is in question, then a cost study can readily be made without missing some of the previous remedial work.

To study these forms in operation, some field examples of this particular form are discussed in detail.

FIELD EXAMPLES

Example "A"

This 2700 foot well was placed on pump in October, 1956, using secondhand, noncorrosion resistant rods. It had its first 5/8 inch rod part at 1275 feet in March, 1958. The second rod part occurred in May, 1958, and the third in September, 1958, at which time the rods were replaced. Calculated rod stress was 13,400 psi which is 50 per cent of maximum. The pumping speed was 12 x 36 inch SPM which eliminates the possibility of failure due to harmonics. Laboratory tests indicated corrosion was the reason for failure and after the third failure, one-half of the rod string was replaced. The string has since been performing satisfactorily.

Example "B"

This is a well that was pumping at 6500 feet with 10 x 100 inch SPM. The well was placed on pump in August, 1956, and the first rod coupling break occurred in October, 1957 at 3400 feet in the 7/8 inch couplings. Second and third breaks occurred in December, 1957 at 2950 feet and 2485 feet in the couplings. The breaks were analyzed and found to be caused by corrosion in the couplings. The 7/8 inch rod with slim hole couplings were replaced with standard type couplings and have performed satisfactorily since.

Example "C"

This was a 6600 foot well which was placed on pump in July, 1957, with 2 inch x 1-1/2 inch x 16 foot standard insert pump. In October, 1958, the pull rod broke at the top of the plunger. The pump was serviced and the pull rod parted in November, 1958. The normal 11/16 inch pull rod was replaced with a 7/8 inch pull rod and has been operating satisfactorily.

Example "D"

This 2700 foot well was placed on pump in August, 1956, and was pulled in April, 1957, due to a scaled-up pump. A similar pump was installed, then pulled in June, 1957. A stroke-through pump was used to replace the standard pump and has been in service for 22 months.

CONCLUSION

These are only a few examples of utilizing some types of systematic approach to subsurface equipment in oil well pumping. If an operator would keep these forms and discuss them with the pump repair shops when wells do not perform satisfactorily, some of the problems could be eliminated. The purpose of this paper is to point out that each time a failure occurs there is a definite reason for its occurrence. If failures are frequent, it becomes necessary to eliminate the cause, if economically feasible. By doing this, the same quantitiy of oil can be lifted at a lower cost.

Each time a rod job is performed, the average cost of the pulling unit and pump repair is $235.90 for a 2500 foot well and $365.09 for a 6500-7000 foot well. These are yearly averages for 175 pumping wells, based on normal road time and lost time.

High expenditures for well pumping make it necessary to evaluate pumping problems, in order to try to reduce pumping costs.