WELLSITE MONITORING AND CONTROL OF ROD PUMPED WELLS

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INTRODUCTION

Out of the 497,000 producing wells in the United States today, over 461,000 (92.8 percent) require some type of artificial lift in order to get oil from the formation to the stock tank. At present, 78.9 percent of all the producing oil wells in the U. S. are being lifted by the familiar sucker-rod pumping method.[1]

There will be an estimated 562,000 failures in downhole equipment this year, of which more than 376,000 (67 percent) will be failures in subsurface rod pumps and sucker-rod strings. The producing companies will spend a little over \$1/2 billion repairing subsurface equipment this year, and nearly half of this amount (\$244,000,000) will be spent in material and labor to repair and replace rod pumps and sucker rods. The cost to the industry to maintain rod pumping systems is a very significant factor in the overall economics of the industry. These estimated costs do not even include the cost of tubing and casing failures, surface equipment repairs, or the production which will be lost while detecting, responding to, and repairing these 3/8 million pump and rod failures.

Despite, the high cost of maintenance and repair, the sucker-rod method is used for producing 85 per cent of the artificially lifted wells. One advantage of the sucker-rod method of production is the simple appearance and high visibility of the system. That is, a lease operator can look out across his lease and see if the beam on the surface unit is going up and down. Unfortunately, the assumption is often made that if the beam is moving production is being maintained. Also the sucker-rod system is an old tried-and-true system which is fairly easily understood by both technical and non-technical personnel. Archeologists tell us that the Egyptians understood and used the walking beam principle for drawing water in 476 A.D., and in the early days of the Roman Empire, the Romans were using wooden sucker rods when drawing their household water.[2] The sucker rod pump system is also readily adaptable to small leases or to widely separated wells, and it is a relatively safe system because there are no high pressure gases or liquids to contain at the wellsite.

However, the single greatest advantage of the sucker rod pump is that with this system the producing bottom hole pressure can rather easily be reduced to a near zero condition, if there are no other problems.[3] The lowering of the producing pressure relieves most of the wellbore pressure on the producing horizon allowing a freer flow of fluids from the formation into the well. For most of the 367,872 stripper wells, this ability of the rod-pump system to draw down the bottom hole pressure, along with the comparatively low equipment cost, allows production of these very low-pressure wells. Unfortunately, this greatest advantage also leads to what is perhaps the greatest single factor in causing sucker-rod system failures, that is, the pumped-off, fluid-pounding well. There is no doubt that the high stress created in the rod string of a pounding well is the major factor causing many, if not most, of the 173,000 sucker-rod failures which will be encountered this year.

The following is a brief review of the basic operation of the sucker-rod pump, of what fluid pound is, and of how fluid pound develops. Methods used with some of the commercially available wellsite-control systems to monitor and control and the pumped-off well and the more prolific producers are also examined.

ROD PUMPING FUNDAMENTALS

The subsurface sucker rod pump is a positive displacement, reciprocating type pump consisting of 4 basic components: (1) a pump barrel, (2) a pump plunger which provides a dynamic fluid seal when assembled inside the barrel, (3) a traveling valve which closes to lift production from the well, and (4) a standing valve which opens to allow fluids to enter the pump. Figure 1 illustrates the four basic components as they are arranged in a traveling plunger pump.

In the pumping cycle illustrated in Figure 1, a rod string activating the pump plunger in accordance with the movement of the surface pumping unit is used. At the instant before the plunger begins to move upward, the pressures above and below the traveling valve are equal and the traveling valve closes because of the weight of the ball. When the plunger then begins to travel upward, as in Figure 1a, all the fluid above the traveling valve is lifted with the plunger because the traveling valve is closed and the plunger and barrel form a fluid seal. As the plunger during its upward travel evacuates the space below the traveling valve, the pressure between the valves becomes lower than the pressure in the

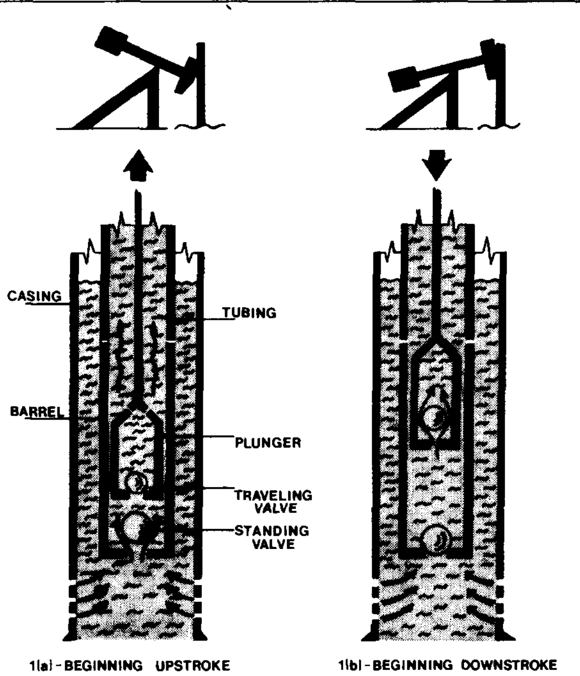


FIG. 1—NORMAL PUMPING SEQUENCE

tubing-casing annulus and the standing valve opens allowing well fluids to flow into the pump. Thus, the void created by the plunger movement is filled. How fast and how well the annular fluids follow the plunger is determined mostly by the height of the fluid column in the annulus (i.e. pump submergence). On the upstroke, the weight of the entire colmn of fluid within the tubing, plus some frictional load is carried by the rod string in addition to the weight of the rods in the fluid. When the plunger reaches the top of the upstroke and pauses before beginning the downstroke, the pressures above and below the standing valve equalize and the standing valve closes.

With the standing valve closed and the plunger beginning to travel down, the traveling valve opens when the pressure between the pump valves becomes greater than the pressure exerted by the column of fluid in the tubing. Then, as is illustrated in Figure 1b, the plunger travels down through the production fluid which has just been allowed to enter the pump during the upstroke. When the traveling valve opened at the top of the downstroke, the weight of the fluid in the tubing has been transferred from the rod string to the tubing. On the downstroke, the load carried by the rods is the weight of the rods less some frictional forces. The change in polished-rod load between the upstroke and the downstroke is essentially the weight of the total column of fluid in the tubing. This load change occurs almost instantaneously as the plunger starts down when the pump is full of liquid, but it is a smooth, gentle transition because the plunger is traveling downward at a very low velocity.

FLUID POUND

What happens when the annular fluid level gets so low that the pump is not filled completely during the upstroke is an entirely different matter. If the pump chamber does not fill completely, a gas pocket is left under the traveling valve during the upstroke as is indicated in Figure 2. After the standing valve closes and the plunger starts moving down, the traveling valve will not open until the gas is compressed to the hydrostatic pressure of the tubing fluid, or (more likely) when the plunger contacts the liquid level in the pump. At the instant the traveling valve opens, as in Figure 2c, the weight of the tubing fluid is transferred from the rod string to the tubing. When this instantaneous load transfer occurs, the plunger is already traveling at a substantial velocity and the rod string will actually compress and bend due to the sudden and drastic load reduction. This bending causes the outer fibers of the sucker rods to to separate, forming small traverse cracks. Repeated bending has the same effect as bending a paper clip back and forth: it breaks after a few bends. This instantaneous load transfer when the plunger contacts fluid is called "fluid pound" because the shock which is transmitted to the surface sounds like someone pounding on the pump at the bottom of the hole. Not only does fluid pound destroy the sucker rods, but the tubing also undergoes a sudden elongation or expansion, causing joints to loosen and leaks to develop. The pound also puts a negative torque or backlash on the wrist pins, bearings, and gears in the surface pumping unit leading to premature failure of the unit.

FLUID POUND CONTROL

The problem of fluid pound can, of course, be corrected by several methods. The most straightforward approach is to reduce the pump displacement by slowing the pumping speed, shortening the stroke length, or running a smaller bottom hole pump. But this is not always a practical solution because of the limitations of the relatively few fixed sizes and adjustments available on a particular installation. Since the adjustments and sizes at our disposal are not infinitely variable, it may not be possible to exactly match the inflow rate of the well to the bottom-hole pump displacement. If the maximum inflow rate is greater than the adjusted pump displacement, production is lost and income is reduced. On the other hand, if the producing capacity of the well is less than the adjusted pump displacement, fluid pound and the resulting equipment overstressing is not eliminated. Also, there are almost continuous changes in the reservoir, well, and producing equipment which will require frequent readjustments to be made in the pump displacement. These changes require continuous monitoring in order to match the pump displacement to the producing capacity of a well.

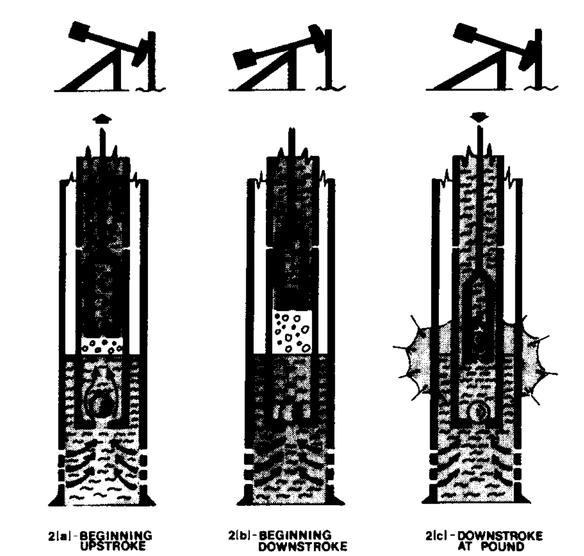


FIG. 2—FLUID POUND SEQUENCE

Probably the most economical and practical way to maintain the pump submergence high enough to fill the pump barrel on each stroke is to pump the well until the fluid level is low and then stop pumping for a short time to allow more fluid to seep into the wellbore. This way the lifting equipment can be sized to handle the maximum production that is expected and compensate for normal efficiency losses due to wear. The well is pumped as long as there is fluid available to be lifted, the bottom hole pressure is maintained at a relatively low level, and the fluid pound is minimized or even eliminated. This method of pumping a well allows response to production and equipment changes by merely pumping for a longer or shorter time as is required. However, knowledge of how long to pump the well and exactly when to stop is the key to operating in this manner.

WELLSITE CONTROL SYSTEMS

Over the years, many schemes for detecting and controlling the pumped-off condition have been devised. By far the most widely used method of automatically controlling pumping wells is the time clock by which pumping and shutdown times are set in fixed increments. The time clock is a simple, inexpensive way to keep a well from pounding excessively, but once the time clock is set it will not change until someone resets it. The time clock does not adapt automatically to changing conditions. Even arriving at a proper time clock setting, if analyzing instruments are not available, is rather inefficient. Often to find an adequate time cycle, the well operator must try a setting, check the well's production that day, feel the polished rod for overheating and pounding, and then try a different setting the next day if a problem is found. Perhaps by the time an optimum time cycle is found, the well's producing capacity has changed or an equipment failure occurs and the whole process must be started over again.

There is, and always has been, a real need to automatically determine exactly how long to pump a well and to detect when a well should be shut down. Today there are systems available which will monitor a well for pump-off and other irregularities and then shut down the electric motor on the pumping unit when an abnormal condition occurs. These are the electronic wellsite-monitoring and -control systems which are being marketed by several manufacturers. Basically, all the monitoring and control system consist of a device which monitors the well's condition and sends an electrical signal to an electronic-logic and -control panel. The electronic panel logic interprets the condition of the well based on the signal it receives and then decides whether the well is producing normally or whether there is an abnormal condition. If an abnormal condition is detected, the electric motor on the unit is stopped automatically.

Each manufacturer monitors the well performance in a somewhat different manner according to the mechanism used to monitor the well. In general, there are three catagories of monitoring mechanisms which are illustrated in Figure 3. These three classifications are as follows.

1. Mechanical-load variation devices which detect abnormal changes in the loading of various components of the surface equipment. These devices include vibration sensors which detect the shock load imposed on the surface unit when fluid pound develops and beam-stress and polished-rod load sensors which detect unusual forces in relation to the position of the sucker-rod stroke.
2. Electrical-power demand-variation devices which respond to abnormal loading of the electric motor during the pumping cycle to detect an unusual condition. These are closely related to the mechanical load devices since the electric load demand is directly proportional to the rod load.
3. Production-monitoring devices which respond to a change in production from the well to detect abnormal conditions.

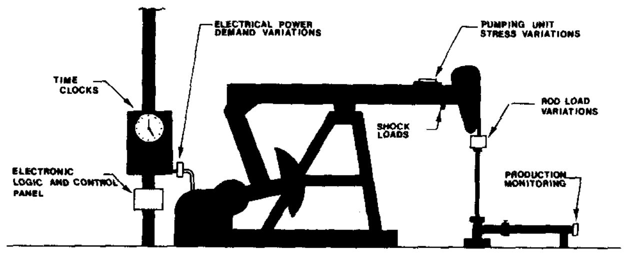


FIG. 3—TYPES OF ROD PUMP CONTROL MECHANISMS

MECHANICAL LOAD CONTROLLERS

Mechanical load variation devices respond to the changes in loading of various force-carrying members to detect the abnormal pumping condition. These devices include shock-load sensors, but these detect only pump-off after pounding has developed and are not really wellsite condition monitoring and control systems.

Mechanical-load variation controllers basically adapt the dynamometer from a periodic pumping-condition analyzer to a continuous-condition monitor. The normal dynamometer is an instrument which measures the total force acting on the polished rod. Usually the polished road load is recorded graphically as a function of stroke position, and is shown as a curve similar to that shown as a solid line in Figure 4. The upstroke begins at the lower left corner of the curve and the stroke continues clockwise. As the traveling valve closes, the plunger lifts the fluid in the tubing and the polished-rod load increases and maintains a high value until the upstroke ends. When the well is pumping normally, the rod load then falls off when the polished rod starts downward because the fluid load is transferred from the rods to the tubing. The

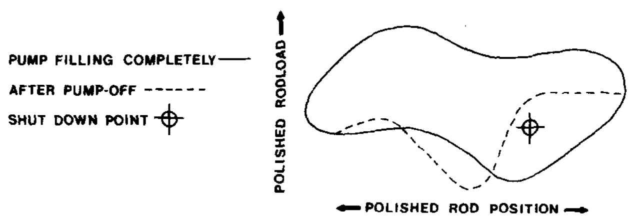


FIG. 4—DYNAMOMETER SHOWING CHANGE IN LOAD AT PUMP-OFF

downstroke begins at the upper right corner of the dynamometer. However, when a well pumps off, this decrease in rod load does not occur at the beginning of the downstroke but rather at a later time in the cycle when the traveling valve encounters liquids in the pump barrel. This condition is shown as a dashed curve in Figure 4.

Now to develop a pump controller, it is merely necessary to monitor the polished rod load in relation to the polished rod position with a rod-load sensor and a position indicator. Then, if the polished rod load has not decreased below an adjusted set value by the time the downstroke of the unit has progressed to a given position (shut down point, Figure 4), the well can be shut down to allow production infilling. Controllers based on this principle have been marketed.

An extension of the concept described above is also being marketed. Rather than monitoring polished rod force, the walking beam stress which is directly proportional to rod load is measured continuously by a strain gauge transducer, and an electronic signal sent to the logic panel is analyzed in a manner similar to dynamometer interpretation. Besides monitoring beam stresses, the logic analysis also differs in that pump-off is detected not by the magnitude of the stress level but rather by a response to rate of change of the decreasing load during the downstroke. As shown by Figure 5, when the high velocity load transfer occurs at pump-off, the slope of the decreasing load or stress becomes steeper. With this type logic, when the rate of change (slope) of the load exceeds a certain adjustable value, pump-off is detected and the pumping unit is halted to allow production feed in.

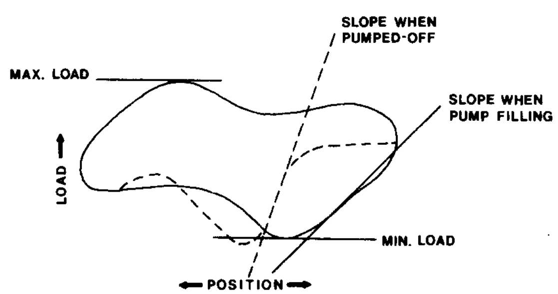


FIG. 5—DYNAMOMETER SHOWING CHANGE IN SLOPE AT PUMP-OFF

ELECTRICAL LOAD CONTROLLERS

The second category of wellsite monitoring and control systems is the electrical load variation or power demand sensing devices. One of the first attempts at detecting pump-off using the electrical load demand of the motor was to sense the heating effect of the current being drawn by the electric motor as the current passed through a resistor. In theory, as long as the down-hole pump is filled to capacity on each stroke, the motor draws current in a steady cyclic manner, keeping the enclosed resistor heated to a point above a certain minimum temperature. If the well pumps off, however, the current demand is less during the first part of the downstroke allowing the resistor to cool to a temperature below a thermostat setting and the well is shut down. This concept works well until cold weather sets in and cools off the thermostat.

On the market today are electronic wellsite monitor and control systems which operate on the principle that, if the pumping system is properly balanced and is lifting a full pump barrel of fluid on each stroke, the current drawn by the electric motor is the same on the upstroke and the downstroke. When the well pumps-off, and the fluid load is carried by the rods on part of the downstroke, the current drawn by the electric motor is decreased. As the pump barrel continues to fill less on each stroke, the time of low current demand by the motor during the beginning of the downstroke increases as is shown by the dashed lines in Figure 6. To sense pump-off there are two approaches now being used. The first approach is to monitor the current demand only during the downstroke. If the current drawn by the motor during the downstroke has not exceeded an adjusted ampere setting at a given polished rod position, the motor is shut off to allow bottom hole infilling. This shut-down point is indicated in Figure 6. The second approach to controlling pumping wells by monitoring the electric motor current demand is to electronically calculate the average current drawn during a full pump stroke. The average current for a pump stroke with the pump barrel filled completely is shown as a solid horizontal line in Figure 7. When the barrel does not fill on the upstroke and the current drawn during the downstroke remains low until the traveling valve opens, the average current will also be lower as

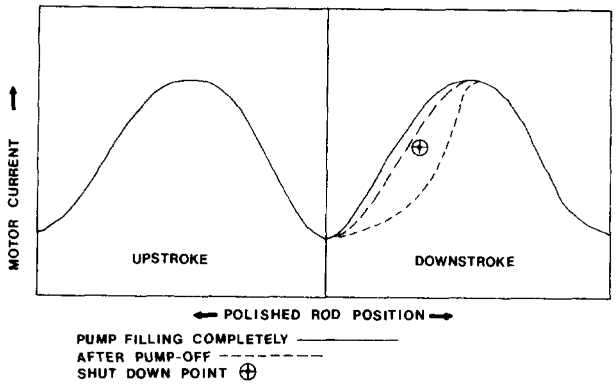


FIG. 6—MOTOR CURRENT VS POLISHED ROD POSITION

shown by the dashed lines in Figure 7. As the pump-off advances, the average current also decreases until it drops below an adjusted reference current (or voltage which is proportional to the current). Once the average electrical power demand is below the reference level, fluid pound is confirmed and the pumping unit motor is turned off.[4]

PRODUCTION MONITORING SYSTEMS

The third type of wellsite monitoring and control system is the production-monitoring type device which responds to a change in production from the well to detect an abnormal pumping condition. The principle upon which the production monitoring system is based is that a well will produce a certain total volume of fluid during a certain interval of time when the pump barrel is filled on each stroke. Whenever the volume of produced fluid per-time-interval changes, a changed producing condition has been created.[5] With this type system, a sensor is installed in the surface flowline at the wellsite to monitor the change in fluid flow.

The basis of the logic with this type of system is that during each full pump stroke there is a period of high flow and a period of lower or no flow of fluids from a well. If the length of time of the high-flow interval is measured when the well is pumping normally, this measured time can become a standard for comparing all future pump strokes. However, comparing each pump stroke with a standard stroke will lead to erroneous results due to normal variations in well and equipment performance. So the time of high flow is averaged or accumulated for several strokes or for a certain time such as 1 minute. The accumulated production time per minute can then be compared with the production time for other minutes of pump operation to detect abnormal conditions. Actually the high-flow accumulation is the summation of the total time that the production flow is above an adjustable detection level as shown in Figure 8.

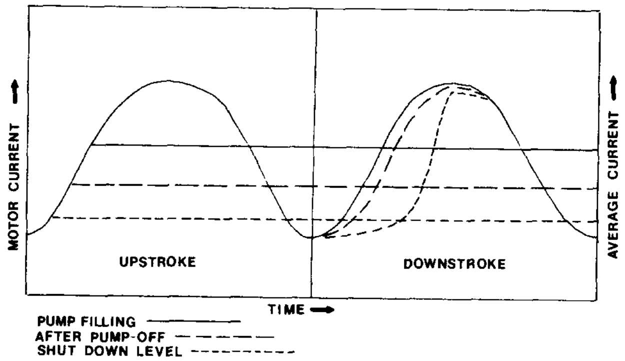
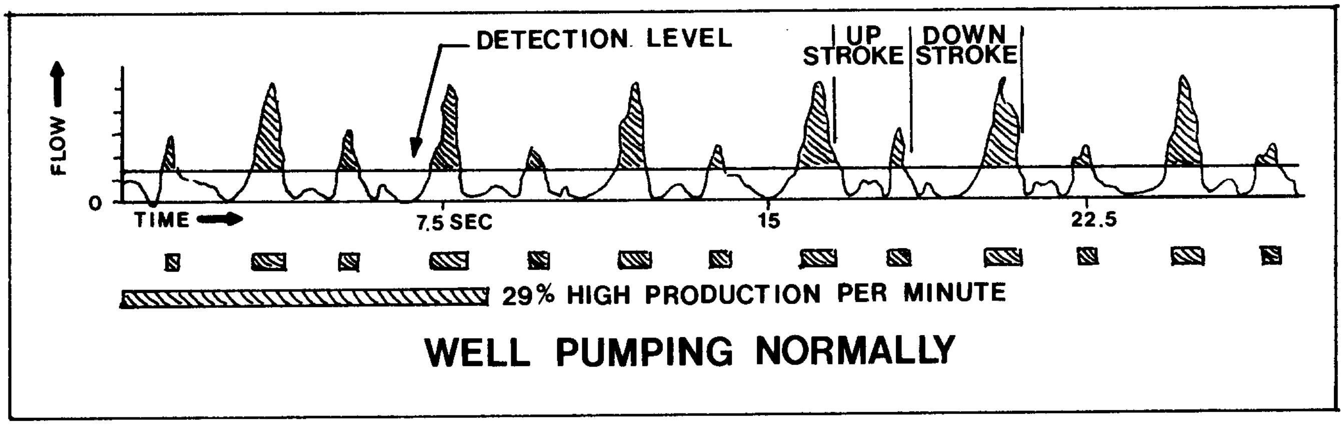


FIG. 7—AVERAGE CURRENT VS TIME

When this same well pumps-off, the total time per minute that the production flow exceeds the detection level is decreased by the time between the beginning of the downstroke and the traveling valve opening. This time change may be quite short for each stroke but the decrease will be markedly different when the production time is accumulated for a minute and will become even shorter as pump-off advances and less fluid is actually pumped (Figure 8b). Once the accumulated high-production time-per-minute falls below a value set for the particular well being monitored, pump-off is confirmed and the electric motor is shut off to allow fluid infilling at the subsurface pump.

BENEFITS OTHER THAN PUMP-OFF CONTROL

Besides responding to pump-off, sophisticated electronic wellsite controllers provide other benefits. One of the main benefits is the intrinsic ability of the wellsite monitors to detect many of the common failures in lifting equipment. For example, these electronic systems, either as a standard part of the system or as an optional equipment feature, detect and respond to rod parts, tubing parts, stuck pumps, and gas locks. Some of the control systems, especially the production-monitoring type, also respond to stuffing box blow-outs, tubing leaks, and faulty pump valves. When an equipment malfunction is detected, the controller shuts down the electric-motor drive permanently and activates a warning device to inform the lease operator that the



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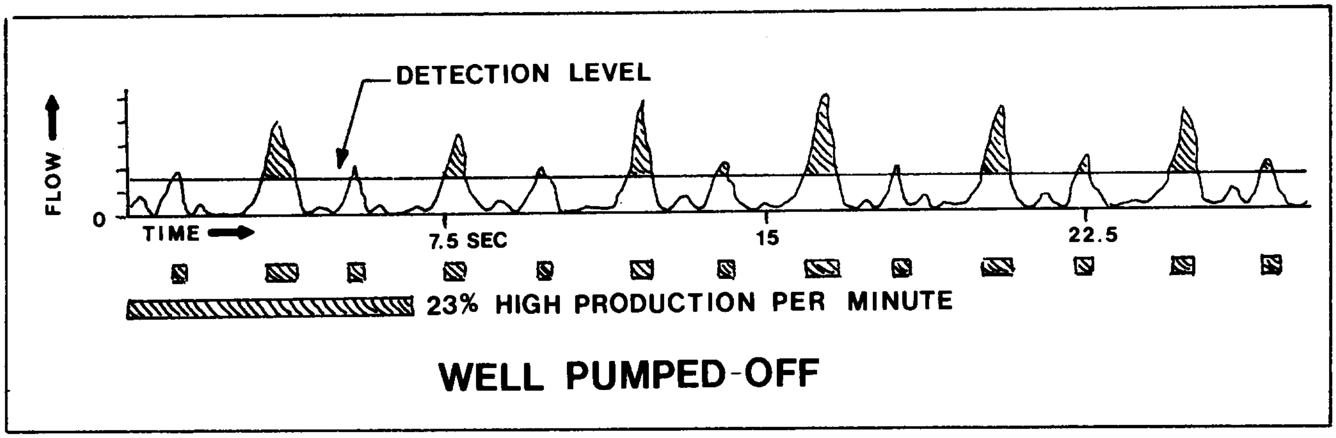

8(b)

FIG. 8—PRODUCTION VS TIME

well is off production. The early detection of equipment malfunctions alone can often justify the decision to purchase. One operator having 10 years experience with rod-pumping automation in West Texas reports that the malfunction alarm feature of the pump-off controller has led to an increase in current production of 2-to-3-percent by earilier detection of wells being down or off in production rate.[6]

However, the major benefit received from the installation of wellsite monitoring and control systems is optimization of production. The rod-pump controller allows the well to pump as long as production is available to be lifted or as long as the production equipment is capable of lifting the fluids. Even after power problems in the field, the well is not shut down until all the accumulated production is pumped out.

The wellsite systems also provide the operator with a continuous record of well performance. This is done by displaying, in some manner, the total pumping time of the well. With this information, the operator can easily tell if production is rising or decreasing by taking periodic readings of the accumulated pumping time. If production trends are not confirmed at the test battery and pumping time is changing, equipment deterioration can be recognized and remedial workovers planned before the well goes off production. See Figure 9.

SUMMARY

The operator of a rod-pumped oil well has available to him today a means to reduce, if not eliminate, rod parts and other equipment damage caused by fluid pounding. The means is the electronic wellsite-monitoring and -control systems

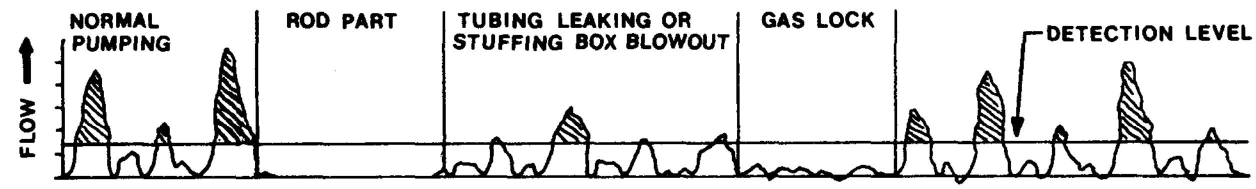

FIGURE 9

that are available commercially. Various devices are employed by different manufacturers of the control systems to recognize abnormal pumping conditions, but all have the same basic purpose. That is, they help the operator optimize the production from his well by monitoring the well so that the maximum amount of fluid which the well is capable of producing, or the maximum amount which the installed equipment is capable of handling is actually lifted.

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