SUCKER ROD LIFTING HORIZONTAL AND HIGHLY DEVIATED WELLS

Norman W. Hein, Jr., Oil & Gas Optimization Specialists, Ltd.
Jeffrey DaCunha, Lufkin Automation
Scott Long, Flexbar
Mark Mahoney, Harbison-Fischer (now with Lufkin)
Russell Stevens, Norris

ABSTRACT

Horizontal and highly deviated wells have been used around the world to extend reach, increase reservoir contact and ultimately, increase production. As with most well considerations, drilling, completing and operating these wells should be based on the entire field support team input and decisions should not made just based on only one technical concern. This paper will provide a review of published information where sucker rod lift has been used to produce highly deviated and horizontal wells. Additionally, some useful recommended practices from equipment suppliers will be included on design, selection, and changes to consider for rod lift equipment when used to produce horizontal versus vertical wells.

BACKGROUND

A recent review of the history, cost and benefits for horizontal wells was written by Mr. S. D. Yoshi in 2003.[1] He provided that while horizontal wells were reported in 1927, the major effort for drilling these wells was in the 1980s. Initial wells were short radius and only about 250 feet long. In 1985, the first medium radius well was drilled with a downhole mud motor. This type of well is now most commonly drilled. It has been reported through 2002 that approximately 17,300 horizontal wells have been drilled in the USA. The majority of these wells (~43%) were drilled in the Austin Chalk. The Red River formation in North Dakota had the next highest amount of these wells.

The majority of horizontal wells in carbonate formations have been in California and Alaska. The most common clastic reservoirs (consolidated or unconsolidated sand) were offshore and international locations. Currently, these wells have been successful approximately 65% of the time with drilling costs approximately 1.5 to 2.5 times the costs of similar vertical wells. However, finding costs for horizontal well drilling have been reported to be 25 to 50% less than buying reserves. Additionally, operating costs ($/bbl) are typically 50% less than similar vertical wells due to the higher productivity.

It is easy to see why there is great interest in horizontal wells, but, these wells have the same operating phenomenon happen to them as with similar vertical wells. This includes reducing reservoir pressure with time and an associated decreased in production rate. Thus, artificial lift should still be required to maximize recovery over the total well life.

The major attribute of sucker rod lift (SRL) is being able to obtain the highest drawdown and, thus, the maximum production from a well during any reservoir pressure condition. This makes the application of SRL to horizontal wells of great interest, provided that operational concerns can be overcome. These concerns are typically related to downhole gas separation or handling gas in the pump as well as the potential for increased downhole wear of rods, couplings and/or tubing, especially if the SRL pump is placed in or below the well bend radius.

The prior publications using SRL in horizontal and highly deviated wells follows. This provides a starting point for considering future installation. Additionally, best recommended practices or key learnings for well design, downhole pumps, use of sinker bars and sucker rods for these wells will then be provided.

SRL in HORIZONTAL WELL PUBLICATIONS

The use of SRL in horizontal wells in Venezuela was for directional, heavy oil wells in the Orinoco Belt[2]. The prior problems with these steamed wells, where bottomhole temperatures were approximately 400^{o}F, included rod/ coupling and associated tubing wear. Top hold-down tubing pumps, with typically 2 ¾-inch diameter plungers, were pumped with 144-inch stroke at 8.5 strokes per minute (SPM). The design of the downhole steel centralizer bar that had a helical array of steel rollers that were tried as replacement for elastomeric rod centralizer (or guides) is shown in Figures 1 and 2. This product is similar to the Wheeled Rod Guide Coupling commercially available from Oilfield Improvements Inc., Tulsa, OK. The installation of the steel roller guide in 1990 provided over 249 days of operational time versus the normal elastomeric guide operational life of 90 days with no rod or tubing failures.

Probably the best operational paper summarizing sucker rod lifting horizontal wells was provided by Cortines & Hollabaugh in 1992[3]. This paper provides a history of problems encountered and solutions that Oryx and their equipment suppliers developed for the Austin Chalk reservoir wells in the Pearsall Field, Frio County, TX. Originally, the most horizontal wells flowed over 1000 bopd. When the wells declined to 100 to 200 bopd, they became candidates for SRL.

They found that if pumps were placed above the horizontal bend and lateral, volumetric efficiency and pump intake pressure declined mainly due to gas interference. Then of the 150 installations, over 80 pumps were placed in the curved or lateral portion to lower the pump intake, increase drawdown and increase production. They developed an equation for the maximum length (L) of downhole tool/equipment versus well dogleg severity that could be safely run. This equation is:

$$L=2*Ro*\{1-(Rx-Ro)^2\}^{0.5}$$

Where: R0 = R+ 0.5 * ID; Rx = R-0.5*ID + OD; R = 5730/A; A=dog leg angle in degress/100 ft.

Typically, wells were pumped using 86 rod string designs with Grade D sucker rods and operating at 6 to 9 SPM. Rod guides were installed on the portion of the rod string in the curve and horizontal section using 8guides/rod. Typical guided length was 1200 ft. in the horizontal and 300 ft. of string guided above the kick off point. A sucker rod string rotator also was installed. They found that a Kevlar® composite guide, available at that time, performed best followed by nylon composite and then a Ryton® material guide. A schematic of a typical installation is shown in Figure 3.

Downhole pumps and gas interference were the biggest challenges for SRL in these horizontal wells. Originally they tried normal “poor-boy” type downhole gas separators when the pumps were installed in the vertical section above the bend radius. But, when they lowered the pumps in the curves, they had to use packer type gas anchors. The comparison of these separators is shown in Figures 4 and 5.

When they first typed pumping in the curves, normal “vertical” pumps with a chrome barrel and spray metal plunger were used. However, they had short pump run times of less than one month. Runtimes improved to over one year by changing the pumps to a two-stage hollow valve rod to better accommodate gas through the pump. Carbonitrided barrels were used with a carbide insert valve rod guide. Carbide balls and seats were installed along with a -0.004” clearance spray metal box end plungers. Originally spring activated balls in special cages were tried but they had less than a month run life due to wear. The use of this special cage was abandoned when they found that a conventional ball and seat arrangement operated normally even in the horizontal section. After making all the appropriate changes, the total horizontal well failure frequency (FF) was 2.5 failures/well/year. This compares to the vertical well FF of only 1.3 failures/well/year. While the horizontal had increased failures, the increased production more than made up for the increased operating expense.

In 1993, Rondy and Cholet investigated pumping horizontal wells in heavy oil using electric submersible pumps[4]. While not specific to SRL, the problems encountered are still applicable. They found that heavy slugging in gassy horizontal wells dramatically decreased production and caused damage to the production equipment. Results of tests on downhole separators showed the need to calculate downhole gas production rates at the pump intake. Then a suitable separator to optimize production should be selected. Tests also showed that it is easier to separate gas-liquid mixtures with increasing viscosity when the fluid flow regime is slug flow. However, when dispersed bubble flow, viscosity was an unfavorable factor.

Shell’s Peace River, Alberta, Canada was producing 6 to 9^{o} bitumen from cyclic steam wells in approximately 80 ft. sand zone. The paper by Zatka in 1999 provided a summary of their experience comparing producing these wells using conventional pumping equipment versus a long-stroke pumping system (Rotoflex®) [6]. The bottomhole temperature of these wells was as high as 420^{o}F, which precluded all but SRL for lifting these wells.

Originally, D1824-305-240 conventional pumping units with 200 horsepower (Hp) Toshiba NEMA B motors and a 200 Hp Allen Bradley Model 1336 variable frequency drive were installed on these wells. After producing a few wells, it was found that only a D1280-305-240 unit and 100 Hp motor and drive would be required.

Tests were conducted on three wells that had Rotaflex model #900 R320-360-288 pumping unit with 75 Hp motor and drive. All wells were equipped with 3-3/4 –inch tubing pumps, 1-inch COROD® rod string, typically 4-1/2 –inch production tubing with the well approximately 1900 ft long that included an approximate 800 ft. lateral section. Pumping speeds were approximately 3.2 SPM vs. ~3.3 SPM for the Rotoflex vs. conventional unit, respectively.

It was found that they could successfully pump these multilateral – horizontal wells using either type of equipment. However, since the Rotoflex had a much longer stroke length (288 vs. 240 –inch) than the conventional unit, it was able to produce 41% more production and pump efficiency increased from 46.8 to 67.6%. Not explained was that this comparison did not try to have equalized production rate versus trying to standardize on the same slow pumping speed. The results also showed that a mechanical long stroke unit can offer a cost effective lift solution. Additionally, the "advantages" from the production uplift "outweighed" several operational, well servicing issues with the long stroke units.

In 1999, Evans and Muth provided a paper that discussed development of the "Muth Pumping System[7]." This system included a special "downhole conversion kit" that allowed installation of a dual string system (one for power; one for production). It was discussed that this system would mitigate pumping problems in horizontal wells, especially wells that had solids production problems.

The sucker rod string was installed in the power string with conventional insert, tubing, or progressing cavity pump. The tubing was then filled with a benign liquid such as fresh water, light oil, kerosene diluent, etc. The conversion kit downhole below the power string included a polished pull rod, a sealing unit, and a crossover flow head that allowed the producing string to be sized to have high velocity to carry sand/solids and an upper standing valve to prevent fluid flow-back. By separating the produced fluid from the power fluid, allowed acceptable production without the downhole equipment coming in contact with the solids problems in the produced fluid. A sketch of the system is shown in Figure 6.

It was stated that in 1999, over 400 horizontal wells were being produced in California mainly using cyclic steam injection. There was difficulty trying to gravel pack the horizontal section (~1000 ft. to 1500 ft. long) with slotted or perforated liners. There also were some production zones that produced a fine, "flour" sand with particle diameters of 1/10000-inch or less.

The Muth Pump System was tested in four wells that were producing 11^o to 13^o API heavy oil. The pumps were placed above the casing liner (approximately 1000 ft. deep) where the well radius was kicked-off for the horizontal lateral. Modified cages with spring loaded balls were needed for the downhole pumps. Early results showed sanding problems were eliminated or greatly reduced. Dynamometer data was to be acquired, but, subsequent testing was stopped when oil prices dropped.

A 2003 Petroleum Technology Transfer Council (PTTC) regional workshop for Michigan discussed the experiences drilling, completing and operating horizontal wells in the state[8]. A summary paragraph on SRL recommendations provided that downhole pumps could be placed in the straight section above the curve, in the curved section, and in the horizontal section itself. It was found that if placed above the curve, while one pump set in the vertical portion of the well could drain multiple laterals; high backpressure and gas separation were operating problems. Placing the pump in the curved section lowered backpressure but it placed the most stresses on the pump and the expected well life was only 30% of the represented vertical well life. If the pump was further lowered into the horizontal section, well run life may be increased to 60% of the vertical life. Furthermore, placing the pump in the horizontal section lowered the backpressure on the well and resulted in increased production. This required pumps to be run through the curve section. This was successfully done at build rates up to 30^o/100 ft. However, the most common build rate was 20^o to 24^o/100 ft. Molded-on rod guides were advisable to be installed on the rods through the curve. Downhole separation also was found to be critical for long run life.

OPERATING AND DESIGN PROBLEMS NOT ADDRESSED

While the above reference and paper summaries provide good information related to using SRL for pumping horizontal wells, not all major design and operational considerations were discussed. Listed below are a few design and operational practices that should be addressed to provide long well run life.

- Valve action in the pump requires the fluid velocity to go to zero. Then the pump ball falls on its seat due to gravity. But, how does gravity work when the pump is not placed in the vertical section? What can be done to help the pump balls go on the seat allowing proper fluid and load transfer?
- What other pump concerns or problems should be considered if the pump is placed in the horizontal lateral?
- Sinker bars normally help reduce the minimum polished rod load, keep the rod string in tension, help reduce rod buckling, etc. However, no publication mentioned sinker bar usage. So, should sinker bars be used for horizontal SRL wells? If so, where should they be placed and how many should be considered?
- Sucker rods normally like to be kept in tension (and this is required for fiberglass rods). How does one know if the rod string will buckle, go into compression and/or have high side loads?
- Is there a way to diminish rod coupling wear by using spray metal coatings, reducing well over pumping and well bore deviation problems?
- Normal guide lines for vertical well bore dog-leg severity provides that:
    - There should be no problem with 0 to 3 degree/100 ft deviation.
    - Deviations 3 to 5 degrees per hundred feet will have increased wear and friction.
    - However, if >5 degrees/100 ft., there will be operation and pumping problems. (This doesn't mean that one can't pump this type of well; it is just that precautions may be required or resulting operating expenses, failures, reduced production, reduced well value, etc. will have to be considered.).

WELL DESIGN/COMPUTATION RECOMMENDATIONS

One parameter that has a major affect the on SRL system is the design/completion of the well and the drilling profile. Of major interest for a sucker rod pump system is where the pump will be landed and operated. Determining the sucker rod string operating parameters, loads, side loads, effect of well-bore deviation, etc. are a very complicated design concern.[8,9] Figure 7 presents the typical Wave Equations that have been established for design of vertical wells and the SRL string design parameters. However, a much more complicated equation has to be considered for horizontal or highly deviated wells as shown in Figure 8.

The forces that act on each sucker rod in the rod string have to be computed for every element using the well bore deviation or drilling plan. Figure 9 shows the typical loads on a rod element while the resulting rod string design and effect of the well drilling plan or resulting wellbore after drilling on the SRL rod string is shown in Figure 10. This shows how the well is drilled and where planned kick-off or bend radius can make a big difference on the rod string operating parameters and resulting system design and equipment sizing. In summary, it is recommended that the "L" profile should be considered best with a pump landing as close to the 90^{o} as possible. The "S" profile or multi-profile well can be problematic but sometimes it is possible to pump.

It is critical that the production engineer and operations be involved in the well plan decision making before drilling commences. This will require that the effect of the well design on the rod string are computed before drilling the well and drilling program adjusted to optimize the effect of the wellbore on the rod string design parameters. Then after the well is drilled, appropriate wellbore deviation survey, with the deviation per 100 ft. interval (max) be recomputed to see if there should be any adjustments in the rod string design before running the downhole equipment in the well. The results of a well deviation model may assist with placing rod guides and determining the number of rod guides per rod to minimize side loads from the well bore deviation and prevent the anticipate rod, coupling and/or tubing wear.

DOWNHOLE PUMP RECOMMENDATIONS

The well deviation survey needs to be used to find an area with the least amount of deflection and the least rate of change (or unplanned deviation or dogleg) over an area of at least 1 ½ to 2 times the pump length. Thus, the type of pump (top or bottom hold-down) and the overall pump length (which are dependent on the surface/downhole stroke and plunger length) to position the seating nipple to be in the desired landing spot.

Experience has shown that rod pumps worked with build rates from 6 to 16 degrees per 100 ft. on most wells with a few in the 18 to 20 degrees per 100 ft. deviation. Some horizontal wells have been pumped in the curved section at 30 to 45 degrees into a 90 degree curve. Build rates were 7 to 16 degrees. This is different than a dogleg which is a local deviation from the planned build. Ideally, the dogleg severity should be less than five degrees per 100 ft. A schematic of the downhole horizontal well and the setup for a top hold-down pump that was successfully operated in the Pearsall field in Dilley, TX is shown in Figure 11. This stopped plugging off of the pump intake and allows some gas separation from the pump.

Carbide sleeves have been used in the pull tube guide to stop wear but the plunger and barrel still had accelerated wear when trying to pump in a curve. The pump life was typically less than one year and the plungers showed a distinctive tear drop shaped wear on each end of the plunger.

While in vertical wells, some may consider gravity plays a major part in seating the balls, it has been shown that the sucker rod pump valves open by pressure differential and close by fluid flow. This is especially useful for operating in horizontal wells and has been documented above; while gravity helps, it is not essential for proper valve action. However, if during operation a late valve closing is observed on a dynamometer card, then spring loaded cages, such as shown in Figure 12, may be helpful.

SINKER BAR RECOMMENDATIONS

Sinker bars are useful not only in vertical wells but have been found especially useful for horizontal wells. These bars have been helpful to try to keep the rod string (or string sections) in tension, prevent buckling, and provide a larger diameter rod to reduce higher local rod loads/stresses, especially when the rod string goes around the bend radius of the well.

It is recommended to use a computer predictive program (such as RODSTAR-D or SROD) to establish an “existing conditions” design for the horizontal/highly deviated well. Future designs can then be compared to this prior “existing design” to determine if changes are necessary or improvements can be made to decrease operational problems. When “new wells” are being designed, it is recommended that the rod string should first be designed without sinker bars. Then the results of the computer design will help determine where sinker bars may be beneficial. The rod string design should be modified, if possible, to segment the horizontal well into various “vertical” segments. Then consider adding sinker bars to the bottom of each ‘vertical’ section. When using RODSTAR D, the first computer run should be made with “Buoyancy Effects” turned <u>off</u> to check for buckling at the bottom of each vertical section. Then sinker bar footage should be adjusted so that all buckling is contained within the sinker bar segment. After making this adjustment, the computer design should be run but “Buoyancy Effects” should be turned <u>on</u> to check for all the other loadings and operating parameters.

A smaller sinker bar section may be considered on the top of each lower “vertical” segment. The bars are not normally required in the top segment. These bars may assist reducing loads on the string as it travels through the turns, doglegs and deviations in the horizontal well.

After each design change, it is recommended to run the program with “Buoyancy Effects” turned <u>OFF</u> and then <u>ON</u> to check for buckling tendencies and the rod string operational loads and design parameters. Changes to the design should be recorded along with the resulting effect on the SRL system. Then a comparison can be made to select the optimum or best design.

SUCKER ROD RECOMMENDATIONS

The rod string computer program will help assist in the appropriate size and grade of rod to allow the desired amount of fluid to be produced without unnecessarily overloading the rod string. In the past, spray metal (SM) couplings have been used when rod couplings have been excessively worn or corroded. Sometimes there is a benefit for these, especially when there is high velocity fluid and especially when there are solids in the fluid. However, the use of spray metal coupling to prevent coupling wear by trying to solve the symptom versus solving the problem. Over-pumping wells, whether they are vertical or horizontal can contribute to rod buckling and resulting coupling wear. Also, not keeping the rod string in tension by placing a tubing anchor catcher (TAC) as low as practical and then using an appropriate amount of sinker bars can contribute to the downhole wear problems. These problems should be appropriately solved by installing and properly setting a rod pump controller and installing and properly setting the TAC and sinker bars.

Mr. S. M. Bucaram, with Arco Oil & Gas, reported to the 1980 API Committee on Standardization of Production Equipment results of lab tests were conducted on the wear effect of spray metal versus normal API "T" class couplings. Tests were conducted using six different manufacturers' spray metal product and the percentage change in coupling wear recorded. Also the resulting tubing percentage wear and percentage wall thickness penetration were recorded. Applied side load or torque to the coupling and J55 (or in some cases H40) tubing of 100, 50 and 25 in-lbs were used. Additionally, water was originally used as a "lubricant" and then some selected manufacturers' couplings were retested using just the 100 in-lb torque but with oil as the lubricant.

The results of these tests are shown in Tables I & II. Table I shows the full test results for the 100 in-lb torque for the water case for the six different manufacturers. These results show that the use of SM on average reduce coupling wear 82% on average versus the T class coupling. However, tubing wear increased 399% on average while depth of tubing penetration increased 117% on average versus when T class couplings were used. When the tests were conducted with a 50 in-lb torque, the SM coupling had on average 73% less wear; but, increased average tubing wear and penetration approximately 288% and 130%, respectively. When a 25 in-lb torque was applied, the average SM coupling wear was reduced 74% while the tubing wear and penetration increased 380% and 67%, respectively. When oil was used instead of conducting the tests in water, with the 100 in-lb torque and only three of the manufacturers SM couplings, the results should on average a 99% decrease in coupling wear. However, the tubing wear was significantly increased to 1440% while the penetration was 361%. These results are shown in Table II.

These results show that the use of SM couplings may not be the best solution when coupling wear is the problem. However, it should be pointed out that the results of these tests caused manufacturers to change and standardized on the type of spray metal power along with changing the coupling end face/land. These changes have been accepted by the industry and standardized in API Spec 11B. Since these changes have been made, no one has repeated the Arco tests or, at least the new test results have not been published.

SUMMARY/CONCLUSIONS

1. There have not been many papers published on lifting horizontal wells using SRL or even other major lift techniques.
2. As the well life extends and bottom hole pressure decreases, artificially lifting horizontal wells will become more prevalent. Hopefully, operational and equipment supplier experience will be documented and published to allow others to learn from their experiences.
3. Preplanning the drilling and well design to develop optimum well bore design should be done as a team with appropriate computer simulations if/when SRL is considered.
4. The "L" type design for the well keeps the sucker rod string vertical the longest and results in less load and decreased design or equipment sizing considerations.
5. Once a well is drilled, an accurate wellbore deviation survey is very important. It should be conducted with maximum interval length being 100ft.
6. The effects of the actual wellbore deviation should be checked using an appropriate computer program against the original rod string design to see if appropriate equipment changes should be made.
7. Downhole gas separation is important; but, having a SRL pump that can handle the amount of gas going thru the pump is critical.
8. While gravity may help valve action, fluid flow is required to close sucker rod pump valves.
9. Spring assisted cages may be helpful for valve action control especially if viscous fluids are being produced from horizontal wells (but ball wear may be a concern).
10. Pump friction should be minimized by reducing or preventing solids in the pump and by proper metallurgy choices.
11. Sinker bars are very useful in horizontal wells to prevent or control buckling and reduce the dynamic effects on the downstroke.
12. Installing sinker bars in the transition region when the rod string change from vertical and at the bottom of each vertical segment in the curved and horizontal section.
13. Spray metal couplings probably should not be considered to prevent coupling wear; but, the new design and standard materials have not been tested to see if there are changes from the Arco results.
14. Rod guides/centralizers are important to include in the downhole equipment to reduce rod/coupling and/or tubing wear and buckling.
15. Roller rod guides have been used, especially for higher downhole temperatures, but solids may be a concern.

16. Composite rod centralizers, molded on the rods, with up to 8 guides per rod have been successful installed to mitigate downhole wear.

ACKNOWLEDGEMENT

The authors of this paper appreciate their management for allowing it to be presented and published.

REFERENCES

1. Yoshi, S.D., "Cost/Benefits of Horizontal Wells," SPE paper no. 83621, SPE Western Regional/AAPG Pacific Section Joint Meeting, 19-24 May 2003, Long Beach, CA.
2. Rivas, O., et al, "Sucker Rod Centralizers for Directional Wells," SPE paper no. 21131, SPE Latin American Petroleum Engineering Conference, 14-19 October, 1990, Rio De Janeiro.
3. Cortines, J.M. and Hollabaugh, G.S., "Sucker-Rod Lift in Horizontal Wells in Pearsall Field, Texas," SPE paper no. 24764, 67th Annual Technical Conference and Exhibition, SPE, 4-7 October, 1992, Washington, DC.
4. Rondy, P. and Cholet, H.J., "Optimization of Heavy Oil and Gas Pumping in Horizontal Wells," SPE paper no. 26555, 68th Annual Technical Conference and Exhibition, SPE, 3-6 October, 1993, Houston, TX.
5. Zatka, M.J., "Long-Stroke Pumping System at Shell Canada's Peace River Multilateral Thermal Wells," SPE paper no. 54115, 1999 SPE International Thermal Operations and Heavy Oil Symposium, 17-19 March, 1999, Bakersfield, CA.
6. Evans, B.L. and Muth, G.M., "Using New Technology to Overcome Pumping Problems in Horizontal Wells," SPE paper no. 54646, 1999 SPE Western Regional Meeting, 26-28 May, 1999, Anchorage, Alaska.
7. "Horizontal Drilling, Real Michigan Field Experience," PTTC Midwest Region Workshop, 20 March, 2003, Mount Pleasant, Michigan.
8. Xu, J, et al, "Diagnostic Analysis of Deviated Rod-Pumped Wells," SWPSC, p133-140, April 2001, Lubbock, TX.
9. Nolen, K.B, "Diagnosis and Design of Sucker Rod Pumping Systems," Lufkin Automation presentation.

Table I

Arco Oil & Gas results of wear tests from various manufacturers' spray metal coupling vs. weight loss and depth of penetration of J55 tubing with 100 in-lbs of side load with water lubricant.

	Weight Loss		Depth of Tubing
Manufacturer	Coupling	J55 Tubing	Penetration
A	-90	836	300
B	-96	959	389
C	-62	361	114
D	-82	224	48
E	-80	597	50
F	-75	808	252
AVERAGE	-82	399	117

Table II

Arco Oil & Gas results of wear tests from various manufacturers' spray metal couplings vs. weight loss and depth of penetration with 100 in-lbs of side load with oil lubricant.

	Weight Loss		Depth of Tubing
Manufacturer	Coupling	J55 Tubing	Penetration
D	-100	1930	489
E	-98	568	176
F	-99	1843	500
AVERAGE	-99	1440	361

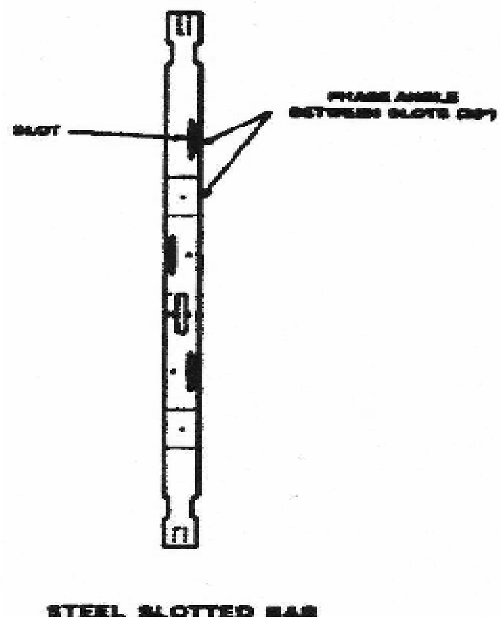

Figure 1 - Steel Slotted Bar drawing from Ref. 2.

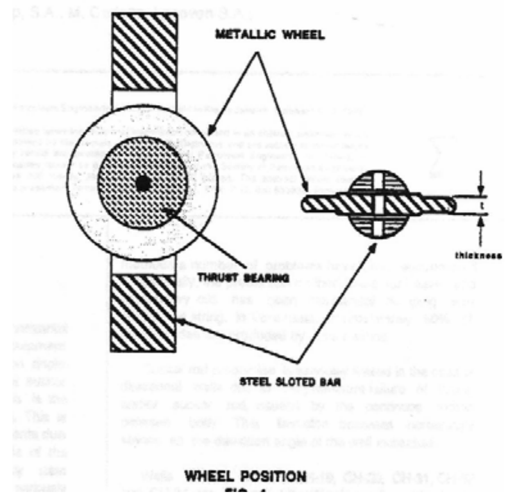

Figure 2 - Steel roller configuration from Ref. 2.

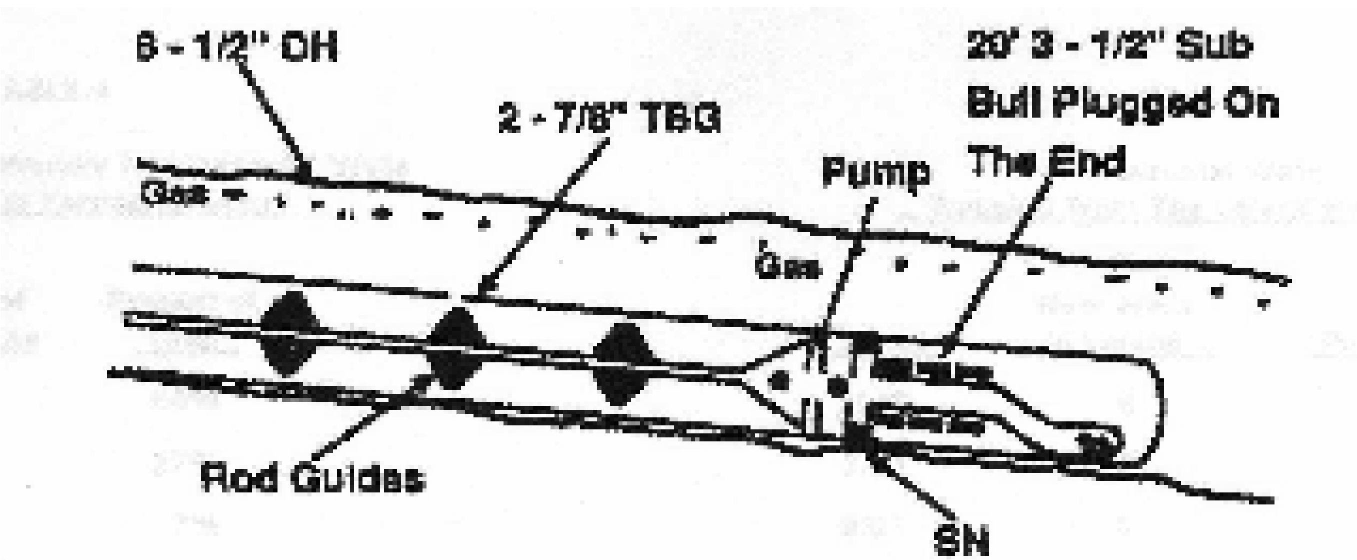

Figure 3 - Typical downhole equipment configuration for pumping horizontal well in deviated well portion. Ref. 3.

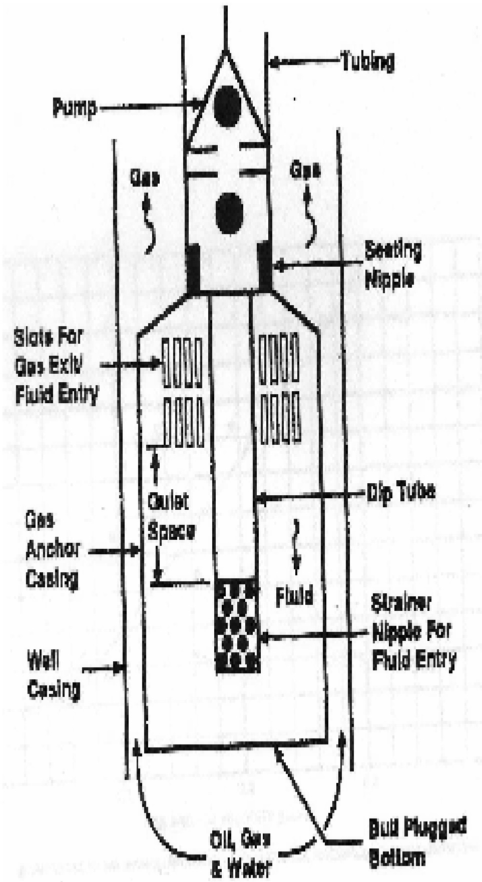

Figure 4 - Poor Boy separator from Ref. 3.

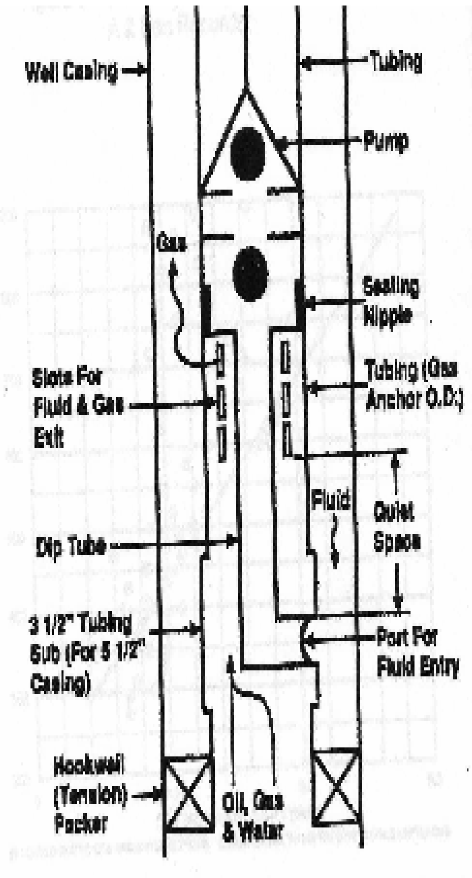

Figure 5 - Packer type separator from Ref. 3.

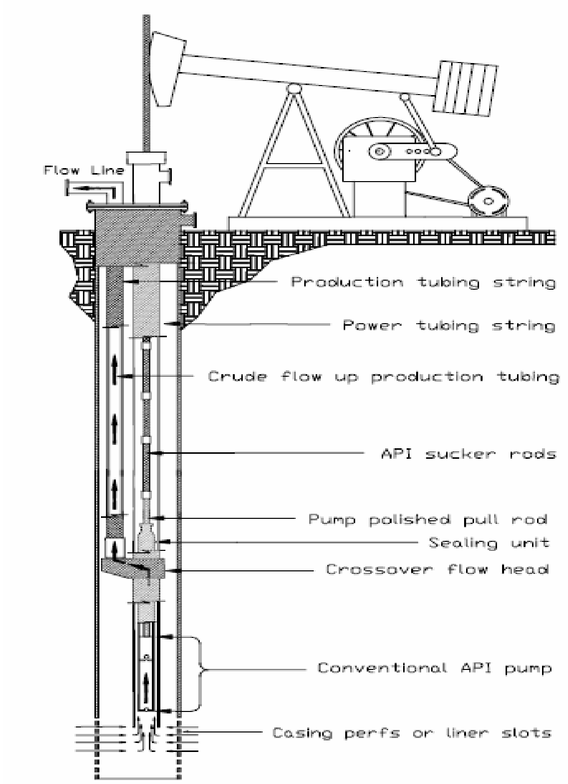

Figure 6 - Diagram of Muth pumping system. Ref. 6.

$$\frac{\partial^2 u(s,t)}{\partial t^2} = a^2 \frac{\partial^2 u(s,t)}{\partial s^2} - c \frac{\partial u(s,t)}{\partial t} + g$$

VERTICAL

Figure 7 - Vertical well Wave Equation. Ref. 8 & 9.

$$\frac{\partial^2 u(s,t)}{\partial t^2} = a^2 \frac{\partial^2 u(s,t)}{\partial s^2} - c \frac{\partial u(s,t)}{\partial t} - C(s) + g(s)$$

$$C(s) = \delta \mu(s) \left[N(s) + T(s) \frac{\partial u(s,t)}{\partial s} \right]$$

$$\delta = \frac{\frac{\partial u(s,t)}{\partial t}}{\left| \frac{\partial u(s,t)}{\partial t} \right|}$$

NON-VERTICAL

Figure 8 - Non-vertical well equations. Ref. 8 & 9.

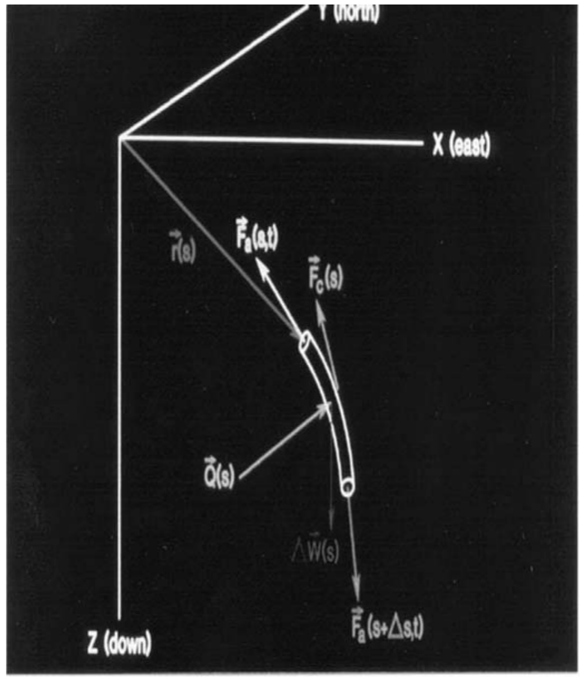

Figure 9 - Free body diagram for sucker rod forces. Ref. 9

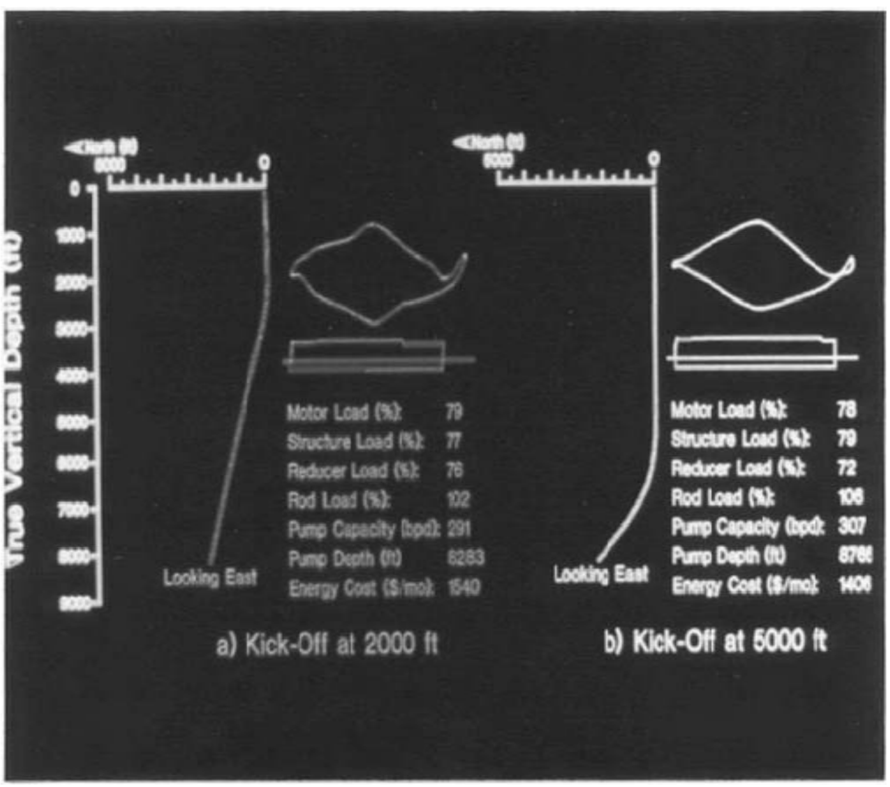

Figure 10 - Comparison of well design and rod string parameters. Ref. 9.

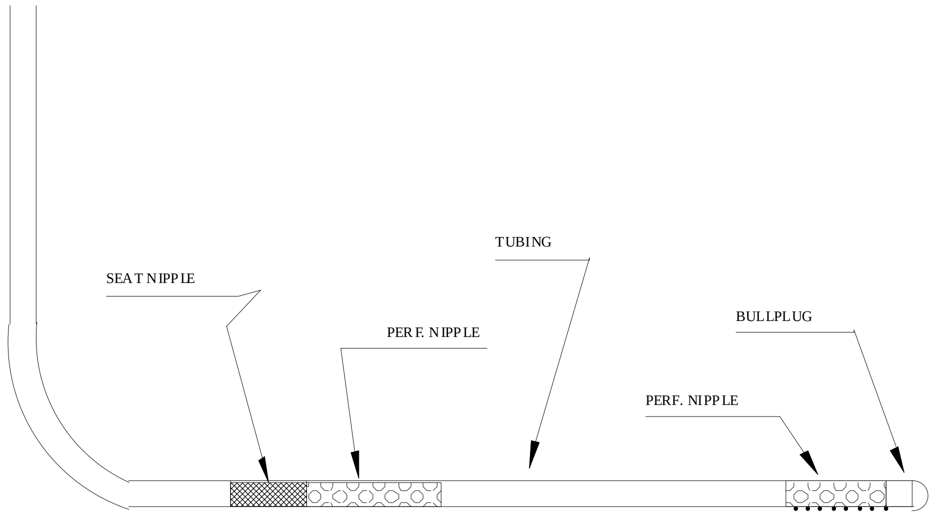

Figure 11 - Schematic of typical successful top hold-down pump for Pearsall – Dilley, TX horizontal wells.

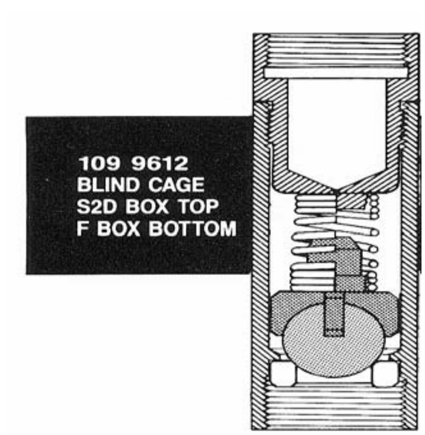

Figure 12 - Drawing of Baird Snubber Cage.