Overview of Beam Pump Operations

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Abstract
Beam pumping systems are the most commonly applied worldwide artificial lift method with 59% of all Artificial Lift in North America and 71% of 832000 wells for the rest of the world (World Oil 2000). This paper reviews many of the concerns that operators face when using the sucker rod pumping system. The beam pump concerns are introduced with a review of the advantages/disadvantages of the system. Next automation and POC are discussed. The most commonly automated operating parameters are examined and the technique of configuring POC set points is illustrated. To maintain efficient operation requires that pumping should be done only when the pump has a high degree of fillage. Methodology for designing to efficiently produce the well by selecting pumping speeds, stroke lengths and plunger diameters are reviewed.

Incomplete pump fillage, tagging on the downstroke, and other downhole conditions contribute to rod buckling and subsequent accelerated rod/tubing wear. Commonly applied solutions such are weight bars and rod guides are stated. Dynamometer cards, particularly calculated downhole pump cards are used for diagnostics of problems that exist in a well.

Finally simple best practices are reviewed covering POC's, use of predictive design programs, guidelines for sucker rod applications, downhole pump best practices, surface unit best practices, tubing, gas separation, use of fluid level detectors (fluid shots), effects of casing pressure, and finally some mention of corrosion solutions. The paper reviews older practice and mentions new concerns that the operator may face. In general, sucker-rod pumping is the premier method of artificial lift. Many operators believe in using only the beam pump system for artificial lift and will only use some other lift method after justifying why not to use beam lift.

Introduction
Beam systems, **Fig. 1** are the oldest and most widely used type of artificial for oil wells. There are about 2 million oil wells in the world and about 1 million wells utilize artificial lift. Over 750,000 of the lifted wells use sucker rod pumps. In the U.S. beam lift systems lift about 350,000 wells. About 80 percent of U.S. oil wells are stripper wells, making less than 10 bpd and these are primarily beam lifted.

Beam Pump System Considerations and Advantages/Disadvantages:
- Beam systems should be considered for lower volume stripper wells. They have proven to be cost effective. Operating personnel are usually familiar with these mechanically simple systems. Less experienced personnel also can often operate rod pumps more effectively than other types of Artificial Lift (AL). Beam systems can operate efficiently over a wide range of production rates and depths. Systems have a high salvage value. Surface units and gearboxes can last in excess of 30 years if not loaded in excess of 100%.

- Beam systems should be considered for lifting moderate volumes from shallow depths and small volumes from intermediate depths. It is possible to lift up to 1,000 BPD from about 7,000 feet and 200 barrels from approximately 14,000 feet (special rods may be required and resultant rates depend on conditions present). More commonly lower rates are lifted from 7,000 feet and few wells are lifted by Beam below 10,000 ft.

- Many parts of the Beam system are manufactured to meet existing standards, which have been established by the American Petroleum Institute (API). Numerous manufacturers can supply compatible interconnecting parts. Also there are many components available that are not API certified, such as larger/smaller diameter downhole pumps (SRP's) extending beyond API sizes.

- The sucker rod string from the surface to the downhole pump is continuously subjected to cyclic fatigue loads. Rods must be protected against corrosion and from damage from running/pulling more than any other AL system, since corrosion introduces stress concentrations and lead to early failures. Special high strength (HS) and fiberglass (FG) rods are available.

- Beam systems are often incompatible with deviated (doglegged) wells, even with rod protectors, and rod and/or tubing rotators. Deviated wells with smooth profiles and low dogleg severity may allow satisfactory performance, even if the angle at the bottom of the well is large (~30-40° and some up to 80°). Some high angle hole systems employ rod protectors and "roller-rod protectors" while other installations with high oil cuts, smooth profiles, and lower angles of deviation use only a few of these devices. High glass content in the protector increases abrasiveness and high glass rod protectors will rod cut tubing. Plastic lined tubing is effective in reducing rod/tubing wear.

- The ability of beam systems to produce sand laden fluids is limited, although there are special filters and sand exclusion devices. Some pumps are designed to either exclude the sand or operate as the sand travels through the barrel-plunger clearance. Special metallurgies are employed for fine sand wear.

- Paraffin and scale can interfere with the operation of Beam systems. Special wiper systems on the rods, and hot water/oil treatments are used to combat paraffin. Hard scales can cause early failures.

- Free gas entering the downhole pump reduces production and causes other problems. Use proper down hole gas separation techniques to restrict free gas from entering the sucker rod pump and efficiently operate with the pump by filling the pump with liquid to eliminate gas interference[1]. The most effective method of down hole gas separation is to set the pump intake below all gas and fluid entry zones. The pump being incompletely filled with liquid is the most common reason for low producing efficiencies and is usually the largest source of energy waste.

- One of the disadvantages of a beam pumping system is that the Polished Rod (PR) stuffing box (which is where the PR enter the well at the surface through a rubber packing element)

can leak. Special pollution free stuffing boxes that collect any leakage are available. Good practice such as "don't over tighten", and "insure unit alignment", are also important.

- A well that attempts to produce more liquid than the maximum liquid that the reservoir will produce leads to incomplete pump fillage, "fluid pound", mechanical damage and low energy efficiency.   Some simple changes in pumping speed and stroke length can be made to match the pump capacity to the production potential of the well. For POC (pump-off controller) systems pump displacements are designed to produce 20-50% more than the reservoir will produce. When the well is pumped-down, a POC will detect incomplete pump fillage and stop pumping to allow fluid entry into the casing-tubing annulus before automatically restarting. Controlling the pump run time with a percentage timer is a low cost method to adjust the number of strokes so that the pump displacement will equal the volume of liquid that flows into well bore. Operating the pumping system with each pump barrel stroke full of liquid is the primary requirement for trouble free efficient operations of the Beam Pump system.

In general, sucker-rod pumping is a premier lift method that should be used if the system can be designed without overloading the prime mover, gearbox (GB), unit structure, and the calculated fatigue loading limits of the rods.

Surveillance and Automation:
Typically beam pump surveillance consists of a pump off controller (POC) monitoring one or more parameters of the Beam system and shutting down the pumping unit when one of the parameters exceeds a limit set by the operator. Common parameters monitored to detect pump off can include PR load and position, electrical current, pumping unit change in RPM and flow line pressures. PR loads are used to evaluate loads on the unit, grearbox, motor, and rods. SPM and stroke length (with pump diameter) relate to production capacity. One common use of pump off controllers is to detect incomplete pump fillage and then turn the pumping system off for a set downtime. The pump off controller restarts the unit after a set downtime and pumps with a pump that is mostly filled with liquid. This on/off cycle is repeated throughout the day and reduces both operating time and operating expense without loss of oil production.

The controller (A) in **Fig. 2** collects and transmits the data, checks parameters to be with-in preset limits and controls on/off cycles of the system. The load cell (B) mounted between the carrier bar and the PR clamp at the top of the polished rod measures load. The position indicator shown as (D) continuously measures position through out the stroke. Position can also be checked by a one-point pickup as the cranks pass a sensor during the pumping cycle. A beam mounted strain gage (E) is less accurate than load cell at (B).

One technique for controlling the unit is to monitor the load/position (plot of surface dynamometer) shown in **Fig. 3**. As the downhole pump becomes less filled (pumped off) and when an input set point is passed on the surface dynamometer card plot, then the controller stops the unit to allow fluid to rise in the annulus before pumping begins again. Some controllers operate using the calculated downhole conditions and the set point can be placed on the downhole pump dynamometer plot.

Fig. 4 sequences from left to right the dynamometer cards as the pump is full, at about 20% incomplete fillage and finally at about 50% incomplete fillage after one minute, as the pump lowers the fluid level to the pump intake and low pressure gas enters the pump with liquids. A typical POC system might stop the unit from pumping, at about 15- 25% incomplete fillage and allow the unit to wait an hour or so until fluids build over the pump before starting again.

The production of sand, extremely cold temperatures or lack of electric power usually means the Beam system must operate 100% of the time. In these cases the designed pump displacement should be near the maximum expected liquid flow rate from the formation, but more attention may be required without POC.

Pumping Speed and Stroke Length Considerations:
For a particular production rate and set of well conditions there are many combinations of stroke lengths, strokes per minute, plunger diameter, pump setting depth and rod string designs. The designer can select different combinations of these parameters that result in the exact same pump displacement without overloading any of the Beam pump system components. The expected liquid inflow at low producing bottom hole pressure is used to determine the pump displacement. Common practice is to size equipment to produce within a range of 90% to 150% of the maximum rate possible from the well. With these many possible combinations the sucker rod system designer often defines a best design practice for his field. His design results in the lowest operating cost / highest operating profit for his particular set of field conditions. But the practice for one field may not be optimum in another field.

Different operators design very different sucker rod configurations for the exact same downhole pump displacement. High pumping efficiency is maintained when the pump is filled with fluid on each pump stroke. Use of a POC requires that the designed pump displacement exceed inflow from the well and that the well not operate 100% of the time for each day. In the initial design for the POC systems larger plunger diameters are frequently used to increase pump displacement in order to pump the well off and utilize the POC's features. But if personal preference or well conditions prevent the on and off pumping cycle, then designing the pump displacement for 150% of the maximum well inflow and using a large diameter pump would be a bad practice. Pumping with a pump filled with fluid is still important when the decision is made to operate 100% of the time. When operating 100% of the time slow pumping speeds, longer stroke lengths and smaller plunger diameters are specified to efficiently produce the well.

The proper design should result in a run life of the rods, pump and tubing downhole system to exceed 3 years between failures. When rod/tubing wear and rod parts are a problem, then a longer stroke and slower pumping speed with a smaller plunger size may reduce rod overloading and rod buckling problems and increase run life[2]. When surface equipment overloading is a problem, then shorter stroke lengths and larger plunger sizes with increased pumping speed will reduce GB failures and torque overloads. Frequently sucker rod failures are caused by factors other than the selection of design parameters and these factors must be corrected before making changes to the design. When the pump is not filled with fluid due to gas interference then actions should be initiated to prevent gas from entering the pump. Increasing the stroke length and the resulting higher compression ratio are often not enough to prevent downhole failures. Downhole equipment failures due to corrosion or foreign material sticking the pump requires

proper chemical treatment to prevent these type of failures, and just changing the operational design parameters will do little to reduce these type of failures.

Rod Buckling Considerations:
Rod buckling can be aggravated by dynamic effects in the rod string, friction between the plunger and the barrel on the down stroke, fluid flow through the TV on the downstroke, tight spots in the tubing, and excessive fluid compression required to open the TV when gas interference and/or fluid pound conditions exists in the pump. Rod buckling is not affected by the increasing hydrostatic pressures versus depth or not affected by buoyancy force of being submerged in fluid, but rod buckling is affected by forces applied to the rods by the pump or the other external forces acting on the rods.

Fig. 5 shows the force to buckle rods for most commonly used rod sizes is less than 100 lbfs. On the downstroke the force needed to buckle the rods to contact the tubing is small and once buckled even more wear occurs.   A force in excess of the buckling force will accelerate rod/tubing wear.

Common practice is to put 200-300 ft of large 1.5 inch diameter sinker bars above the pump where plunger/barrel resistance and fluid pound can occur causing rod/tubing wear. For less severe wear, rod guides may be used in place of sinker bars.

Design: Motor, Pumping Unit, and Rod String
Programs are used to select a pumping unit, design the rod string taper, and size the pump for new or existing wells.   One can easily evaluate which pumping speed and stroke will yield the desired production without overloading the rods, beam, and gearbox. Another use of predictive programs is to check an existing pumping system, to verify that the measured loads match predicted loads of a normal pumping ssystem. The calculated fluid load, Fo, applied to the rods by the pump and the weight of the rods in fluid, Wrf, should match very closely (within 1-3%) to the values measured at the well. If Fo and Wrf measured and calculated do not match closely, then any of the other predicted parameters are likely to be in error. Once these two values match, then other effects such as of motor slip, fluid inertia, and partial fillage can be important in getting a good match between the predicted and measured conditions. Production rate and pump intake pressure are related by the inflow relationship of the well and accurate modeling of rod loading depend on the fluid load which depend on the pump intake pressure determined from the production rate. Motor performance curves may be used to determine the actual speed of the system if the motor is heavily loaded and large speed variations occur during a stroke. The motor/pumping unit slows down as the torque increases and speeds up when the net gearbox torque decreases, thereby affecting rod load and positioning of the peak loading. Peak load, pump and PR horsepower and pump stroke should be predicted within 2-4% of measured data for a normal pumping system.   Predicted minimum rod load is usually higher than actual measured.   Predicted peak gearbox torque is usually higher than actual in-balance gearbox loading, and sizing of the pumping unit is usually large enough for the actual loading that is experienced. Most predictive programs are well suited for designing a sucker rod pumping system. QRod[4] is a very widely used program for the design and prediction of Sucker Rod Beam Pumping Installations and can be downloaded free of charge from the web. Predictions compare

favorably with field measurements. Alternative design programs include Rodstar, Theta Enterprises, Srod, Lufkin Automation and AccuPump, see PLTechLLC.com.

Analysis: Dynamometer Cards

Acquiring surface load and position data on sucker rod lifted wells using a dynamometer transducer has been performed in the oil field for more than 50 years. Measured surface dynamometer cards may not allow the operator to make complete diagnostics of the beam system. Experience in a particular field helps to associate surface dynamometer card shapes to certain downhole problems. Current dynamometer and computer technology result in very accurate measurement of load and position at the surface and prediction of loads along the rod string and down to the pump. During the 1960s the rod string was mathematically modeled (S. Gibbs[5]) using the wave equation, starting with measured surface loads and position to "wave down" the rod string and predict the downhole dynamometer pump card.

The surface dynamometer card is the plot of measured polished rod load versus positions throughout a stroke. Surface dynamometer cards are valuable for diagnosing rod loading, structural loading, and torque loads on the gearbox and prime mover. In very shallow wells, the shape of the card is usually effective in diagnosing pump performance. In deeper wells, the complex dynamics of the Beam system reduces the effectiveness of diagnosing downhole problems from only the surface dynamometer card. The pump dynamometer card is a plot of the predicted load at positions of pump stroke and shows the load that the traveling valve/pump plunger assembly applies to the bottom of the rod string. Identifying how the pump is performing and analyzing downhole problems are the primary uses of the calculated downhole dynamometer plot.

Fig. 6 is the calculated downhole pump dynamometer card shape for the pump filled with mostly liquid and a small amount of gas. The pump is functioning properly and the tubing appears to be anchored. The maximum plunger travel, MPT, is the horizontal distance from A-C. MPT is the maximum length of the plunger movement with respect to the pump barrel during one complete stroke. The fluid load is the height of the vertical line labeled Fo and (Fo from the Fluid Level) represents a force caused by the difference in tubing pressure minus intake pressure acting across the pump plunger seal at the traveling valve (TV). Fo Max represents the load on the plunger for the plunger to lift the liquid to the surface, assuming zero pump intake pressure. The fluid load acts across the traveling valve on the upstroke and the tubing discharge pressure is transferred to the standing valve (SV) on the down stroke. The magnitude of the fluid load is equal to the pump discharge pressure minus the pump intake pressure multiplied by the plunger area. From points B to C the rods carry the fluid load, when the TV is closed. From points D to A, the tubing carries the fluid load, when the SV is closed. The distance from A-D is the effective plunger travel (EPT), EPT is the length of the plunger travel when the full fluid load is acting on the SV.

Successive steps in the pump operation are:
At the start of the upstroke (point A), the traveling valve and standing valve are both closed. The fluid load is fully carried by the tubing prior to point A and is gradually picked up from point A to point B by the stretched rods at point B. The load transfers as the rods elastically

stretch to pick up the fluid load. The pressure in the pump decreases and any free gas in the clearance space between valves expand from the tubing discharge pressure to slightly less than the pump intake pressure. The standing valve begins to open at B, allowing fluid to enter the pump when the pressure in the pump drops below the intake pressure. From point B to C, the rods carry the fluid load as well fluids flow into the pump. At C, the standing valve closes as the plunger starts down, and the traveling valve remains closed until the pressure inside the pump is slightly greater than the pump discharge pressure at D. From C to D, gas in the pump (if present) is compressed as the plunger moves down to increase pressure on the fluid from the intake pressure to the discharge pressure in the tubing; but the plunger does not move if the pump barrel is full of incompressible fluid. As the fluid in the pump barrel is compressed, the fluid load is gradually transferred from the rods to the tubing. At D, the compressed pressure inside the pump barrel is greater than pump discharge pressure and the traveling valve opens. From D to A, the fluid in the pump is displaced through the traveling valve into the tubing on the down stroke and the closed standing valve holds the fluid in the tubing.

Problems may be analyzed through use of diagnostic pump card shapes[7]. These problems vary from incomplete pump fillage due to over pumping the well, **Fig. 7**, or incomplete pump fillage caused by gas being swept into the pump due to poor gas separation at the pump intake, **Fig. 8**. The loss in load from B-C caused by a leaking travel valve can be easily diagnosed by the upside down bowl shape of the pump card. The gain in load on the rods from D-A is caused by a leaking SV, **Fig. 9**. This diagnostic concave-up shape of the pump card from D-A is used to diagnose that the SV pump/plunger assembly is leaking, the closed SV should be applying load to the tubing but pump load is being applied to the rods as the TV closes to act a check valve holding fluid in the tubing in place of the leaky SV.

Fig. 10 is an example of over pumping the well and improper spacing of the pump. The pump intake is set below the fluid and gas entry zone and the well initially starts with the pump filled with fluid. After pumping at 10.4 SPM for a few minutes the well is pounding fluid and the pump is 47 % full. For efficient operation and reduced risk of failure the pumping speed should be reduced to 5 SPM or run time should be controlled using a percentage timer[3] or POC. The pump is being tagged hard at the bottom of the down stroke. Frequently this problem is due to spacing out the pump to have a high compression ratio and having a high fluid level. After the well is drawn down, the increased fluid load results in more rod stretch and the pump begins to tag. This pump needs to be re-spaced to remove the tag and to prevent damage to the artificial lift equipment. On this well on every stroke the severe tag is reducing the life of all downhole and surface equipment.

Some Simple Best Practices:
Analyze the Sucker Rod Lifted Well Involves The Following Steps[6]:
1. Analyze the well's inflow performance to determine if additional production is available.
2. Determine the overall efficiency to identify wells that are candidates for improvement.
3. Analyze the performance of the pump.
4. Analyze the performance of the downhole gas separator.
5. Analyze mechanical loading of rods and beam pumping unit.
6. Analyze performance of prime mover.
7. Design modifications to existing system.

8. Implement changes and verify improvement

Improving The Overall System Efficiency:
1) Maintain high volumetric efficiency:
     a)   Match pumping requirements with wellbore inflow.
     b)   Eliminate Gas interference
     c)   Use Full Pump Capacity by controlling run time with a POC or Timer
2) When System Efficiency is low, find and fix problem.
3) Verify power meter calibration.
4) Mechanically / electrically balance pumping unit.
5) Properly size pumping unit to match well loads.
6) On severely over sized motors where average surface efficiency falls below 50% change out motor.

Perform Complete Acoustic, Dynamometer And Motor Power Survey of Well
1) Analyze the Performance of the Well and the Equipment
2) Determine the well's productivity, the downhole pump performance, the down hole gas separator performance, the rod and beam unit loading and the motor performance.
3) Take steps to maximize the well's production rate
4) Make Recommendations to fix any problems discovered in the analysis of the collected data
5) When the recommended changes to the well are completed, new data should be collected in a few weeks once the well is operating under stabilized conditions.
6) Notice if the well performance has changes as planned.
7) Evaluation of the recommended changes is called the follow-up process.
8) Following-up on recommendations is how experience is gained and the analyst role changes from a data collector to a knowledgeable well analyst and problem solver.

Design Rate in order to use POC:

Design Rate = $\dfrac{\text{Desired Rate x 24 hr/day}}{.80 \text{ VE x 20 hr/day}}$ (Using POC)

Example: Well can make 300 bfpd

Design Rate = $\dfrac{300 \text{ bfpd x 24 hr/day}}{.80 \text{ VE x 20 hr/day}}$ = 450 bfpd

If you design for POC, design for about 1.5 times what the well makes. If no POC, design for what well will make or slightly less if gassy. These recommendations for POC design may be altered or under some conditions POC may not be used. When appropriate the use of POC's has been shown to give approximately 20% reduction in energy costs, 25% reduction in operating cost, and 1-10 % increase in production.

Guidelines for Design Using Predictive Program:

1. Design with no additional load on pump

2. Use default dampening factors

3. A low pumped off level of about 50' should be used for a conservative maximum load on the pump.

4. 100 % pump load should be input.

5. Use motor option for speed variation and use defaults for inertial values.

6. Before accepting a High Strength Rod design, evaluate design of D Rod using a Service Factor of 1.

Rod String Guidelines:

1. Use Grade D rods with T couplings or Spray Metal couplings if wear and economics dictate.

2. HS rods should only be used when absolutely necessary. EL HS rods do not have HS pins. Use HS couplings with HS rods. Be cautious of slim hole couplings with HS rods. Be cautious of HS rods when H2S is present.

3. All rods should be designed with loadings using your field established service factor. If field established Service Factor is not available, then use 1.0 for service factor. Do run HS rods until rod loading on D rods exceed 100% when using a 1.0 service factor.

4. Molded rod guides should be placed on any rods below the anchor. Note: DO NOT RUN ROD GUIDES ON WEIGHT BARS!!

5. Use steel as opposed to FG unless economical to do otherwise.

6. Use lighter % loading with FG (~ 80%) using lowest temperature rating, usually shown in predictive program input/output. FG is used for deep wells when rod loading is a problem. Use FG rods for perhaps 50-70% of the top of the string and steel rods for the bottom of the string to keep the FG out of compression.

7. With FG, a shear tools should be run on all wells that have shown any tendency to stick pumps.

8. Inspect both new and used rods for manufacturing damage, to meet specification, or handling damage.

9. When running rods in well proper handling and make-up with displacement card will reduce early failures and increase run life.

Best Practice for Pumps:

1. Use of larger pumps without overloading the unit and rods.

2. Use a simple design. More complicated pumps fail more and cost more.

3. Use heavy wall pumps. Thin wall pumps have less corrosion and pressure resistance.

4. All pumps should be designed and built where the TV is within 1" of the SV when pump bottoms out on the clutch at the top.

5. Pump leakage should about 2-5% of production. High water cut wells should have more pump leakage. Deep wells can have pumps with smaller clearances. Use new leakage equation with calculated downhole clearances.

Beam Pump Unit Best Practices:

1. The GB and the unit structure load should be below 100%.

2. Perform Yearly Maintenance on Surface Equipment.

3. Use a predictive program to help size the motor. If program says a 32 HP is needed and the next bigger available size is 50 HP, then use it. In general you loose significant energy only when the motor size exceeds about 2X the correct motor size. Use only NEMA D motors.

4. Polish Rods: Spray metal polish rods without liners should be used in all CO2 flood beam lifted wells and corrosive wells. Water flood and primary wells can use either a liner on the polish rod or a spray metal polish rod.

Tubing Best Practice:

1. Use J55 tubing on producing wells with depths no greater than 8500'. For deeper wells, calculations must be made. Use couplings of same grade as the tubing.

2. Run the seating nipple as deep as possible.

3. Minimize the distance between the tubing anchor and the seating nipple. In open hole, the tubing anchor should be as close to the casing shoe as possible. In cased hole, the tubing anchor should be out of the perforated zones. Use caution when setting the anchor below any perforations, because fill may stick the anchor.

4. In wells deeper than 3000 feet justify why not to use a tubing anchor. Corroded casing or small diameter pumps are reasons not to use tubing anchor.

5. Use API modified no lead thread sealant spread over complete thread area.

6. Tubing below the anchor should be inspected for excessive wear on each pull and replaced if worn.

7. Use thread protectors until tubing in derrick.

8. No wrench marks are acceptable on tubing anchors. Use only ISO 9000 replacement parts.

9. A non API seating nipple should be used only on 2 7/8's tubing strings. The API nipple can cause the pump to stick.

Gas Separation Best Practice:

1. The pump intake should be below the gas entry point into the well. If this is not possible, consider the collar size gas separator[1] instead of the poor boy separator.

2. A typical poor boy separator can only be used for low rates (~75-150 bpd). For 2 7/8" perforated tubing sub, a 1 1/4" stinger and velocity between the gas and mud anchor of 1/2 ft/sec, the max fluid rate is 135 bfpd. See "Improved Downhole Gas Separators" paper[1] for other dip tub and tubing combinations for separator liquid capacities.

3. An improperly sized gas separator is worse than no separator as it can trap gas into the pump and the separator can becomes gas locked.

Beam Pumping Unit - General:

1. The unit should have the concrete base set on 5/8's river stock. Sand can wash out.

2. The unit and wellhead must be aligned correctly so the polish rod pulls out straight each time.

3. Each week the unit should be inspected for abnormal sounds, grease or oil leaks, or rust stains at metal joints.

4. On a six month interval, grease all bushings, inspect unit and GB oil for contamination, check tightness of all bolts, follow check list and keep records.

5. Check stuffing boxes daily. Don't over tighten causing wear on polish rod and increased output horsepower from motor.

Fluid Level Detection:

1. Shoot fluid levels regularly, including wells that are on POC.

2. Dynamometer cards can indicate if a well is pumped off or has other problems.

3. Shoot fluid levels when the well is being tested for production rate.

4. Consider a lift revision to increase the pumping capacity if additional potential is indicated.

Casing Pressure:

1. Lower casing pressure is better. High casing pressure restricts flow from the formation in the same manner as a high fluid level.

2. Check the casing side check valve to be sure it is operating properly.

Corrosion:

1. For corrosive wells producing, for instance, H2S, target might be treating with 25 ppm of oil soluble filming amine. The total chemical treatment volume is based on wells total production with the minimum treating volume of 1 gallon. Treating schedules are generally one week apart. For normal water flood wells, flush a volume of 3 bbls water with the treatment. For wells with a gas rate of 100-200 Mfcf/D, use 5 bbls and for greater than 200 Mfcf/D, use 8 bbls of water with the treatment. These recommendations for W. Texas area where H2S prevalent but may provide a starting point for other areas.

2. Check your chemical program or check with your chemical supplier.

3. Before running pump and rods, should be 15 gallons of oil soluble filming amine and 15 bbls of lease crude be pumped into the tubing after a workover. This should be done on wells that have been killed with heavy brine or on wells that have exhibited severe pitting on tubulars or rods. It is optional on less severe situations.

Conclusion

Beam pumping is the most widely used form of artificial lift. Beam pumped wells should be periodically monitored with dynamometer surveys and the diagnostic pump card shapes should be used to insure that the pump has no mechanical problems and efficient operations are maintained. Fluid level surveys should be used to confirm all the available liquid is produced from the well. Percentage timers and POC operate the Beam Pump system only when the downhole pump is filled with fluid else low efficiencies and equipment damage usually result

from gas interference and fluid pound. Applying the simple best practices to beam pumped systems will result in lower operating cost and longer equipment life, but some of the practices may not be best for all fields. Any time the operator makes changes to his normal practices, then follow-up analysis should made to confirm that the new best practice is working as desired.

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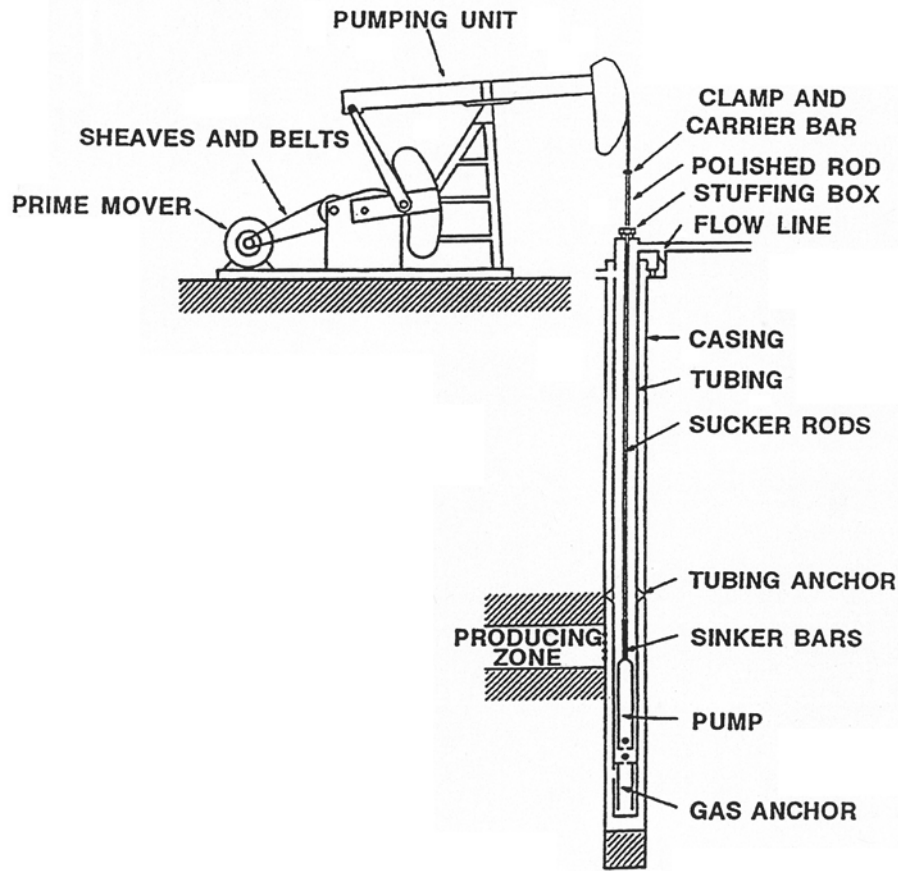
Fig. 1 – Simplistic Beam Pump System

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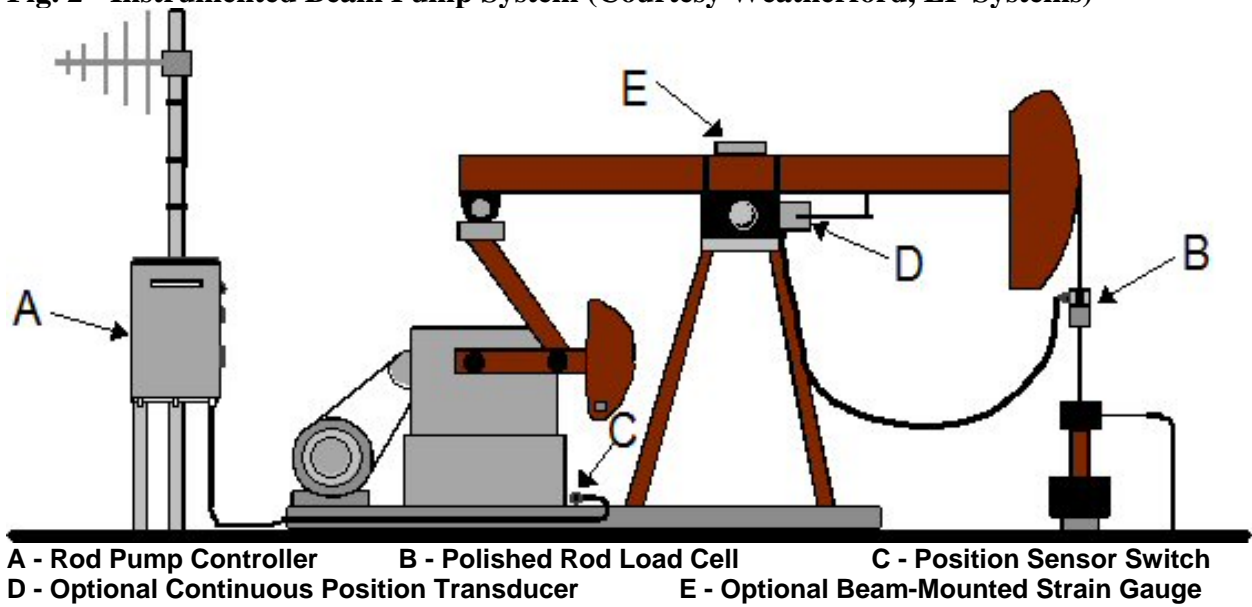**Fig. 2 - Instrumented Beam Pump System (Courtesy Weatherford, EP Systems)**

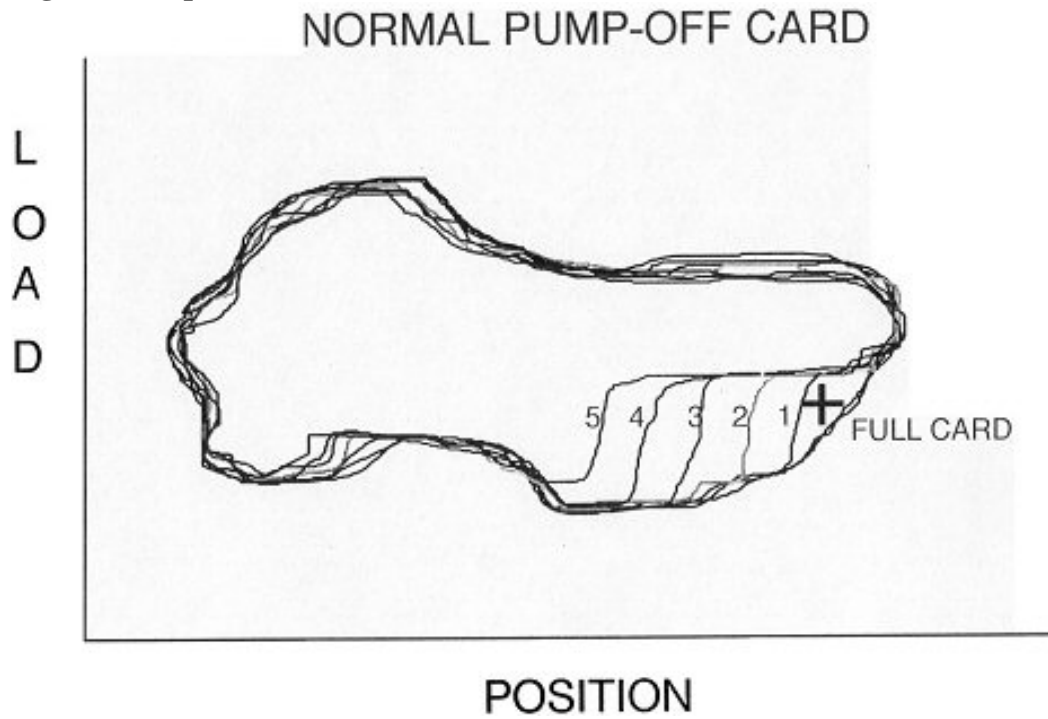Fig. 2 - Instrumented Beam Pump System (Courtesy Weatherford, EP Systems)

A - Rod Pump Controller   B - Polished Rod Load Cell   C - Position Sensor Switch
D - Optional Continuous Position Transducer   E - Optional Beam-Mounted Strain Gauge

Fig. 3 – Pump Off Controller Set Point "+"

NORMAL PUMP-OFF CARD

L
O
A
D

5 4 3 2 1 + FULL CARD

POSITION

Fig. 4 - Surface and Bottom Hole Dynamometer Cards
Progressing from Full, to about 80% pump fillage to about 50% pump fillage.

TIME ZERO   +30 SEC.   +60 SEC.
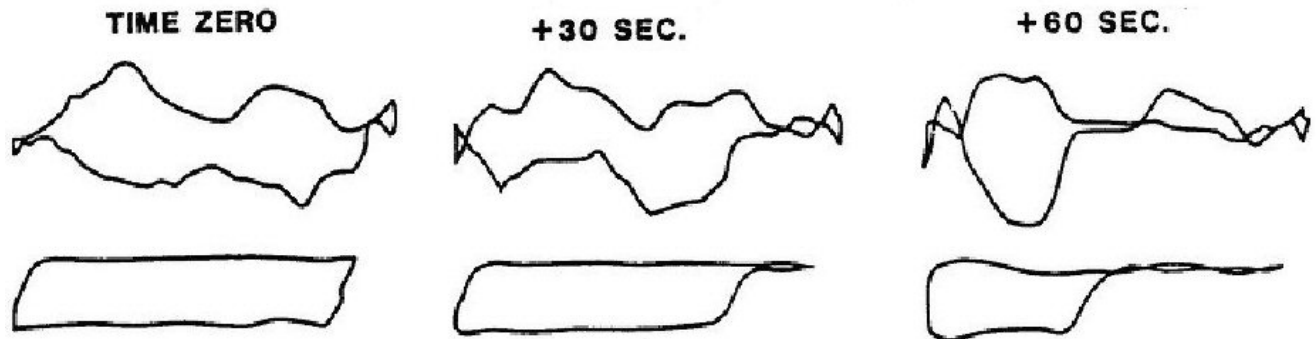
Fig. 5 - Critical Force Required to Buckle Sucker Rods of Various API Sizes

Critical Force vs. Critical Length
Buckling Analysis Results

API Rod #5

Fc, Critical Force, Lbfs

Lc, Critical Length, ft

Fig. 6 - Calculated Downhole Pump Dynamometer Card

Fo Max

Fo From Fluid Level

B

C

Fo

A
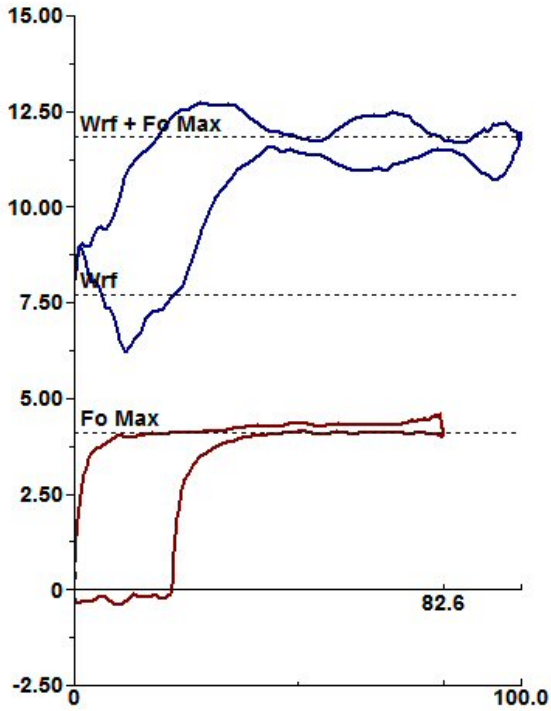
D

0
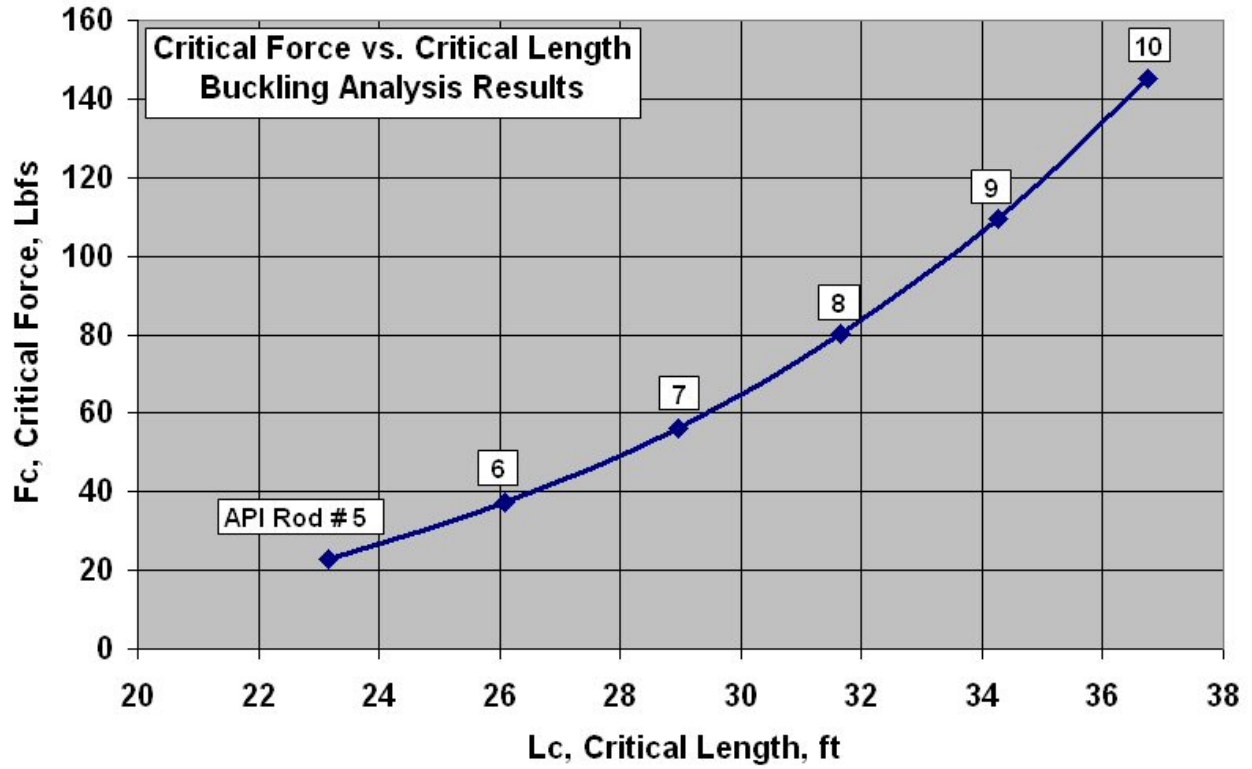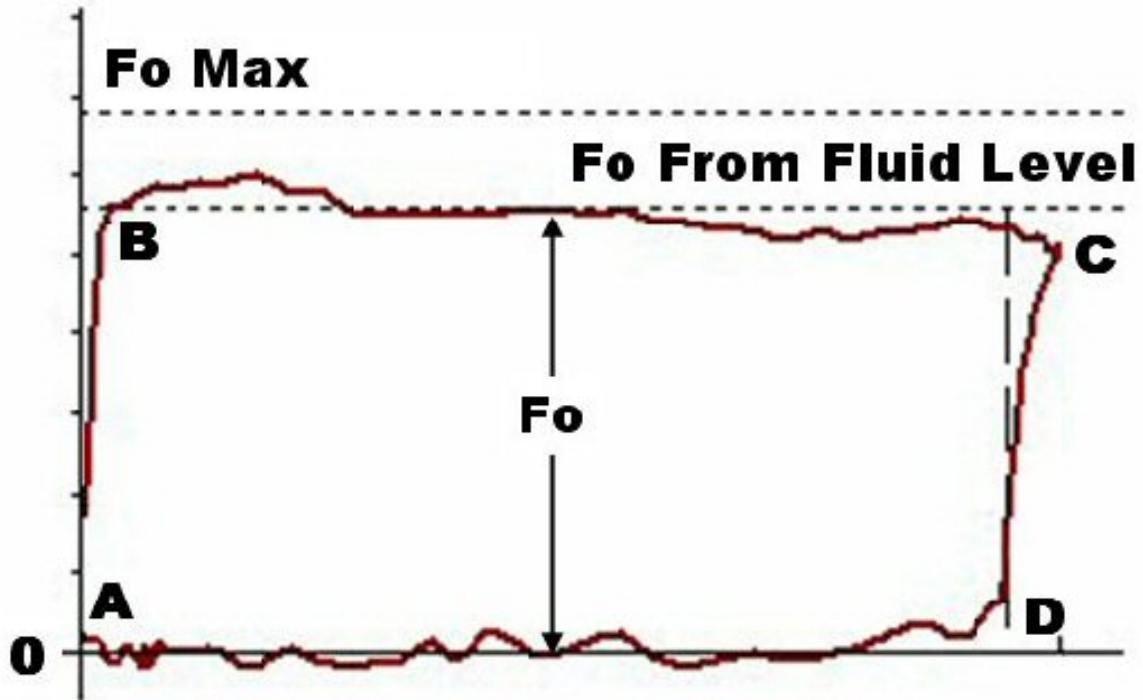
Fig. 7 – Pumped Off Fluid Pound DHC
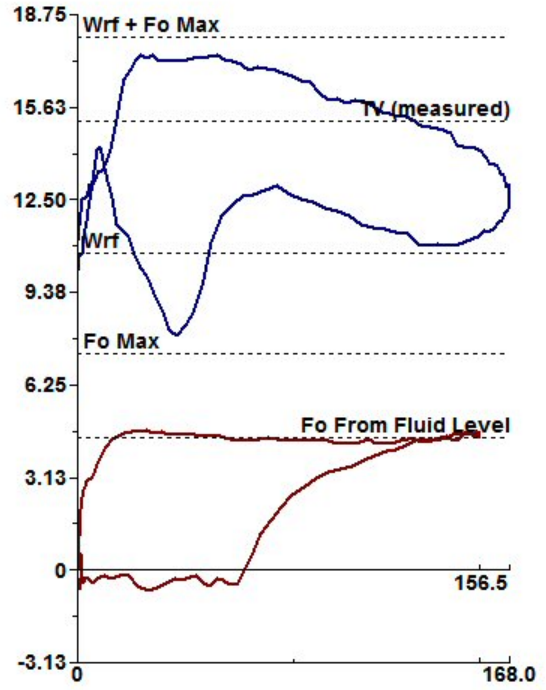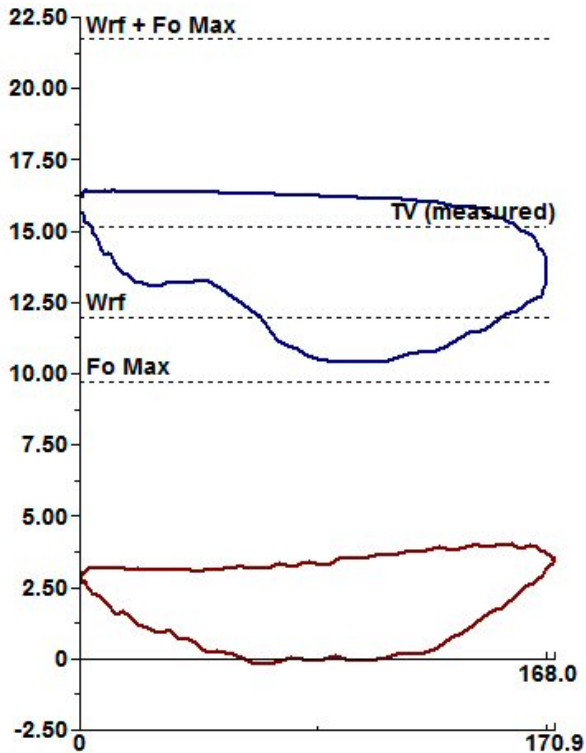

Fig. 8 – Gas Interference DHC

Fig. 9 – Leaky Standing Valve DHC

Fig. 10 – Pump OFF and Tagging DHC